Section:	2	**Page No.:**	21 of 49
Topic:	Application Overview		
Subtopic:	Revenue Requirement		
Issue:	Projected Losses		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states that even with the proposed and indicative rate increases, Manitoba Hydro is projecting losses on electric operations in 2018/19 to 2023/24 totalling approximately $900 million as forecast domestic and export revenue will not be sufficient to cover the increased costs.

QUESTION:

Confirm that the Manitoba Hydro-Electric Board has approved the General Rate Application, including the projected $900 million loss.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro.

RESPONSE:

As noted in Section 2.1, page 2 of IFF14 (Appendix 3.3), the Manitoba Hydro-Electric Board ("MHEB") has approved the rate increases proposed for 2015/16 & 2016/17. The MHEB is aware that IFF14 projects $900 million of losses.

Section:	2	**Page No.:**	21 of 49
Topic:	Application Overview		
Subtopic:	Revenue Requirement		
Issue:	Projected Losses		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states that even with the proposed and indicative rate increases, Manitoba Hydro is projecting losses on electric operations in 2018/19 to 2023/24 totalling approximately $900 million as forecast domestic and export revenue will not be sufficient to cover the increased costs.

QUESTION:

Confirm that the Province of Manitoba Hydro has been consulted and/or briefed on Manitoba Hydro's financial situation, including Manitoba Hydro's IFF14 and the projection of a $900 million loss.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro.

RESPONSE:

IFF14 has been provided to the Minister Responsible for the Administration of The *Manitoba Hydro Act* as part of its regular reporting requirements to the Province of Manitoba.

Section:	2	Page No.:	21 of 49
Topic:	Application Overview		
Subtopic:	Revenue Requirement		
Issue:	Projected Losses		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states that even with the proposed and indicative rate increases, Manitoba Hydro is projecting losses on electric operations in 2018/19 to 2023/24 totalling approximately $900 million as forecast domestic and export revenue will not be sufficient to cover the increased costs.

QUESTION:

File all consultation, briefing and approval documents relating to (a) and (b). If necessary, file in confidence using Rule 13 of the Board's Rules of Practice and Procedure.

RATIONALE FOR QUESTION:

Manitoba Hydro's IFF shows a projected $900 million loss to Manitoba Hydro.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:	Tab 2 Figures 2.4, 2.15,2.16,2.17	**Page No.:**	14
Topic:	Capital Expenditures		
Subtopic:	Cash Flow		
Issue:	Major & Sustaining Capital Expenditures impact on Revenue Requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update figure 2.14 to include the 2008 to 2014 and 2024 to 2034 time periods, on a consistent basis with Appendix 11.37.

RATIONALE FOR QUESTION:

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

RESPONSE:

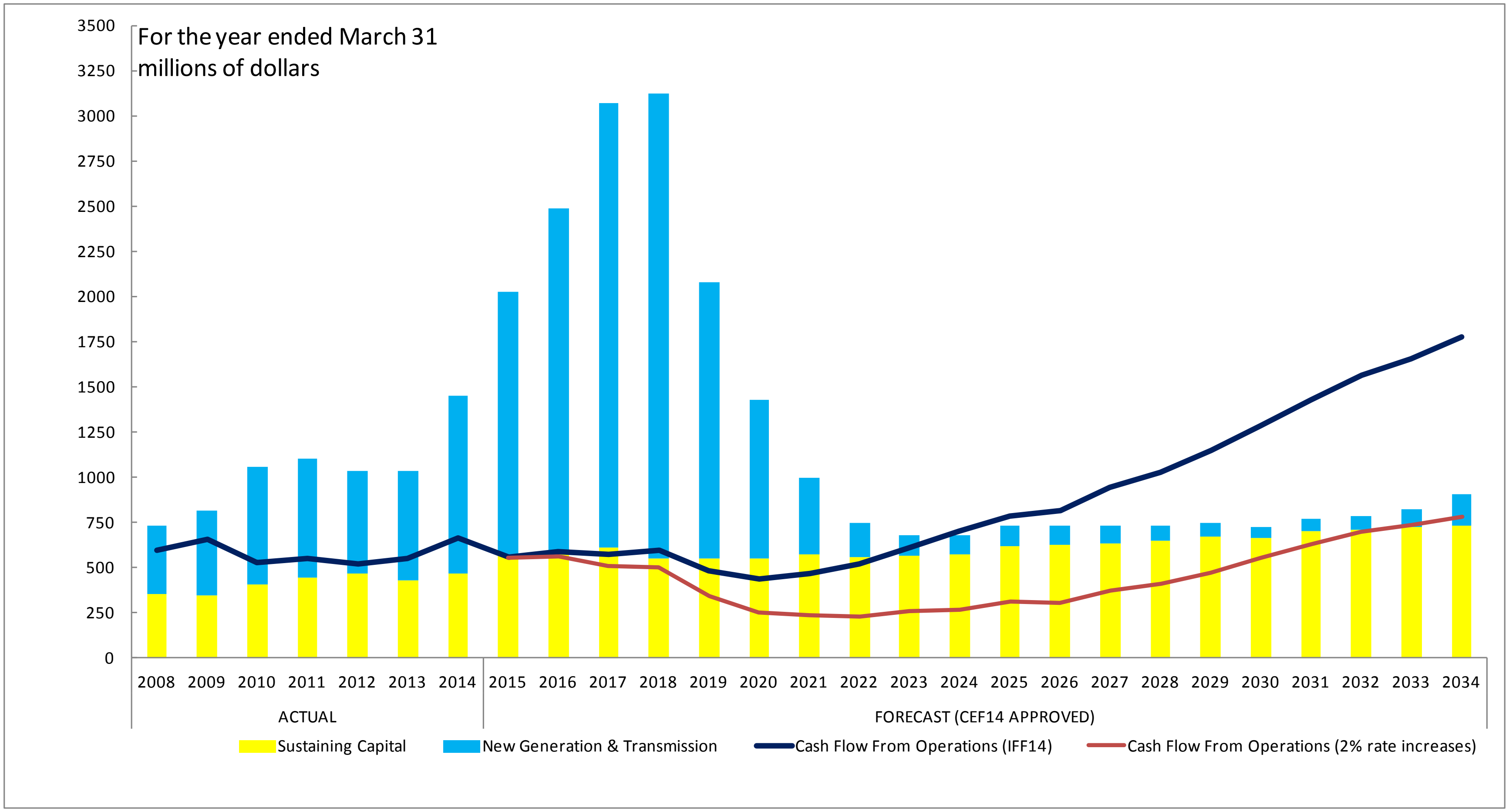
Please see the following chart which includes the capital expenditure and cash flow from operations information from 2008 through 2034.

As indicated for the actual years (2008-2014), Manitoba Hydro has had sufficient funds to cover its Sustaining capital expenditures with surplus funding to cover a portion of the New Major Generation and Transmission expenditures.

In the next 10 years there is significant financial risk and potential for rate volatility as Manitoba Hydro's financial position deteriorates due to the large investment requirements. The cash that is projected to be generated from operations is just sufficient in 4 of the 10 years to fund sustaining capital expenditures.

In the following 10 year period, the indicative 3.95% rate increases and export revenues generated from the Keeyask Generating Station are projected to accumulate to a sufficient level to cover the increased costs and Manitoba Hydro will begin to rebuild its financial reserves.

The cash flow from operations assuming 2% even annual rate increases is also provided in the figure for information purposes and indicates the negative impacts to the cash flow and MH's ability to fund future capital expenditures. This emphasizes the need for a minimum of 3.95% annual rate increases to cover the extensive investments that Manitoba Hydro has to make to continue to provide safe and reliable service to customers.


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)

Section:	Tab 2	Page No.:	
Topic:	Overview and Reasons for Application		
Subtopic:	Rate Increase		
Issue:	Present values of 2015/16 Rate Increase		

PREAMBLE TO IR (IF ANY):

A $60 million revenue increase in 2015/16 in consumer revenue will raise about $1.14 billion over the 20 year time period. This excludes the compounding effects of planned future increases on the (base) $60 million rate sought in 2015/16. MH indicates it needs steady rate increases to meet its planned capital expansion.

QUESTION:

Please provide the present value of the proposed $60 million in revenue increase requested for 2015/16 over the next twenty years of the planning horizon on the basis of i) excluding and ii) including the planned 3.95% increases forecast for each year. Please utilized MH's weighted average cost of capital.

RATIONALE FOR QUESTION:

To understand the full financial implications of the proposed 2015/16 rate increase over the 20 year forecast.

RESPONSE:

The attached schedule calculates the present value of the proposed $57 million additional General Consumers Revenue for 2015/16 over the 20 year forecast excluding the 3.95% increase to be $848 million (6.95% nominal WACC discount rate).

The present value of the proposed $57 million additional General Consumers Revenue for 2015/16 over the 20 year forecast including the 3.95% increase is $629 million assuming no further rate increases over the 20 year period to 2033/34.

In Millions of Dollars

				MH14				PUB/MH I-3(i)				MH14 vs PUB/MH I-3(i)	
	Nominal WACC	**Discount Factor**	**MH14 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	1,437	0.00%	0.00%	-	-	0.00%	0.00%	-	-	-	-
2016	6.95%	1.070	1,454	3.95%	3.95%	57	54	0.00%	0.00%	-	-	57	54
2017	6.95%	1.144	1,460	3.95%	8.06%	118	103	3.95%	3.95%	58	50	60	52
2018	6.95%	1.223	1,483	3.95%	12.32%	183	149	3.95%	8.06%	119	98	63	52
2019	6.95%	1.308	1,490	3.95%	16.76%	250	191	3.95%	12.32%	184	140	66	51
2020	6.95%	1.399	1,501	3.95%	21.37%	321	229	3.95%	16.76%	252	180	69	49
2021	6.95%	1.497	1,506	3.95%	26.17%	394	263	3.95%	21.37%	322	215	72	48
2022	6.95%	1.601	1,513	3.95%	31.15%	471	295	3.95%	26.17%	396	247	75	47
2023	6.95%	1.712	1,525	3.95%	36.33%	554	324	3.95%	31.15%	475	278	79	46
2024	6.95%	1.831	1,538	3.95%	41.72%	641	350	3.95%	36.33%	559	305	83	45
2025	6.95%	1.958	1,551	3.95%	47.31%	734	375	3.95%	41.72%	647	331	87	44
2026	6.95%	2.094	1,565	3.95%	53.13%	832	397	3.95%	47.31%	741	354	91	44
2027	6.95%	2.240	1,580	3.95%	59.18%	935	417	3.95%	53.13%	839	375	96	43
2028	6.95%	2.395	1,593	3.95%	65.47%	1,043	435	3.95%	59.18%	943	394	100	42
2029	6.95%	2.562	1,607	3.95%	72.01%	1,157	452	3.95%	65.47%	1,052	411	105	41
2030	6.95%	2.740	1,624	3.95%	78.80%	1,280	467	3.95%	72.01%	1,169	427	110	40
2031	6.95%	2.930	1,641	3.95%	85.86%	1,409	481	3.95%	78.80%	1,293	441	116	40
2032	6.95%	3.134	1,659	2.00%	89.58%	1,486	474	2.00%	82.38%	1,366	436	119	38
2033	6.95%	3.352	1,677	2.00%	93.37%	1,566	467	2.00%	86.02%	1,443	430	123	37
2034	6.95%	3.585	1,696	2.00%	97.24%	1,649	460	2.00%	89.74%	1,522	425	127	35
NPV							**6,384**				**5,536**		**848**

In Millions of Dollars

	PUB/MH I-3(ii) Assuming No Projected Future Rate Increases				PUB/MH I-3(ii) With Compounding due to Projected Future Rate Increases				
	Annual Rate Increases	**Cumulative Rate Increases**	**Additional GCR**	**Discounted Additional GCR**	**Annual Rate Increases per PUB/MH I-3(i)**	**Cumulative Rate Increases per PUB/MH I-3(i)**	**Additional GCR due to Compounding of Future Rate Increases**	**Discounted Additional GCRdue to Compounding of Future Rate Increases**	**Total Discounted Additional GCR**
2015	0.00%	0.00%	-	-	0.00%	0.00%	-		
2016	3.95%	3.95%	57	54	0.00%	0.00%	-	-	54
2017	0.00%	3.95%	58	50	3.95%	3.95%	2	2	52
2018	0.00%	3.95%	59	48	3.95%	8.06%	5	4	52
2019	0.00%	3.95%	59	45	3.95%	12.32%	7	6	51
2020	0.00%	3.95%	59	42	3.95%	16.76%	10	7	49
2021	0.00%	3.95%	59	40	3.95%	21.37%	13	8	48
2022	0.00%	3.95%	60	37	3.95%	26.17%	16	10	47
2023	0.00%	3.95%	60	35	3.95%	31.15%	19	11	46
2024	0.00%	3.95%	61	33	3.95%	36.33%	22	12	45
2025	0.00%	3.95%	61	31	3.95%	41.72%	26	13	44
2026	0.00%	3.95%	62	30	3.95%	47.31%	29	14	44
2027	0.00%	3.95%	62	28	3.95%	53.13%	33	15	43
2028	0.00%	3.95%	63	26	3.95%	59.18%	37	16	42
2029	0.00%	3.95%	63	25	3.95%	65.47%	42	16	41
2030	0.00%	3.95%	64	23	3.95%	72.01%	46	17	40
2031	0.00%	3.95%	65	22	3.95%	78.80%	51	17	40
2032	0.00%	3.95%	66	21	2.00%	82.38%	54	17	38
2033	0.00%	3.95%	66	20	2.00%	86.02%	57	17	37
2034	0.00%	3.95%	67	19	2.00%	89.74%	60	17	35
NPV				**629**				**219**	**848**

Section:	Tab 3: Appendix 3.4	Page No.:	
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Operating Results		
Issue:	2014/15 Rate Increase		

PREAMBLE TO IR (IF ANY):

This GRA includes the 2014/15 test year.

QUESTION:

Please refile a version of the IFF14 operating statement, balance sheet and cash flow statement to include the interim 2.75% rate increase approved May 1, 2014 as Additional General Consumers Revenue, updating the cumulative rate increase section accordingly.

RATIONALE FOR QUESTION:

The filed statements do not reflect the complete rate increase being sought in the application related to the 2014/15 test year.

RESPONSE:

Please see the attached projected Electric operations financial statements with the 2014/15 2.75% rate increase reclassified to Additional General Consumers Revenue.

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
Response to PUB-MH-I-4 - Interim 2.75% Rate Increase included in Additional GCR
(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	96	157	222	290	361	434	512	595	683
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	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1 194	1 326	1 334	1 349
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	144	145	151	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	1 956	2 044	2 317	2 471	2 920	3 150	3 239	3 304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	2.75%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	2.75%	6.81%	11.03%	15.41%	19.97%	24.71%	29.64%	34.76%	40.08%	45.61%
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	0.86	0.85	0.86	0.91
Capital Coverage	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
Response to PUB-MH-I-4 - Interim 2.75% Rate Increase included in Additional GCR
(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	874	977	1 086	1 200	1 323	1 453	1 530	1 611	1 694
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	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 351	1 348	1 338	1 337	1 321	1 301	1 263	1 197	1 161	1 116
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
	3 346	3 365	3 388	3 415	3 430	3 439	3 432	3 403	3 403	3 404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* 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	51.37%	57.34%	63.56%	70.02%	76.74%	83.72%	90.97%	94.79%	98.69%	102.66%
Financial Ratios										
Equity	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.71
Capital Coverage	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
Response to PUB-MH-I-4 - Interim 2.75% Rate Increase included in Additional GCR
(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	2 238	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	26 585	27 668	28 299	27 727	27 788	27 965
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	3 069	2 214	2 654	2 604	2 104	2 028	2 101
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	2 837	2 902	2 812	2 696	2 518	2 312	2 126	2 001
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	28 299	27 727	27 788	27 965

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
Response to PUB-MH-I-4 - Interim 2.75% Rate Increase included in Additional GCR
(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	2 801	3 049	3 421	3 773	3 629	4 288	4 963	5 703
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
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189
LIABILITIES AND EQUITY										
Long-Term Debt	23 395	24 198	24 401	24 343	24 476	23 749	23 739	23 743	23 737	23 381
Current and Other Liabilities	2 112	1 443	1 373	1 456	1 372	1 968	1 243	1 199	1 132	1 446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 948	1 924	2 007	2 161	2 427	2 826	3 361	4 008	4 732	5 557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
Response to PUB-MH-I-4 - Interim 2.75% Rate Increase included in Additional GCR
(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)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1 222)	(1 349)	(1 329)	(1 341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
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)	(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)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
Response to PUB-MH-I-4 - Interim 2.75% Rate Increase included in Additional GCR
(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	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 348)	(1 353)	(1 354)	(1 371)	(1 368)	(1 360)	(1 341)	(1 250)	(1 230)	(1 200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1 024	1 146	1 288	1 432	1 561	1 655	1 775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	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	403	161	(37)	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	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 045)	(1 051)	(1 056)	(1 062)	(1 091)	(1 087)	(1 134)	(1 125)	(1 182)	(1 275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1 390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1 390	1 844

Section:	Tab 3: Section 3.0 Tab 5: Schedule 5.1.2 p.10	**Page No.:**	2
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states the reason for the rate increases sought is to compensate for lower than forecast export revenue.

QUESTION:

Please update schedule 5.1.2 to include the years 2007/08 through 2011/12. In that updated schedule, please add a row that shows net export revenue for each year.

RATIONALE FOR QUESTION:

The information is required to examine changes to export revenue forecasts.

RESPONSE:

Please see the following Extraprovincial Revenue schedule updated to include 2007/08 through 2011/12 as well as net export revenue information.

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE

Schedule 5.1.2
(000's)
MH14

	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
Canadian Sales	38 497	45 173	41 185	35 890	34 350	33 353	20 392	28 748	16 104	43 626
Other Sales	28	216	(226)	(81)	51	122	(40)	(54)	-	-
Canadian	38 525	45 389	40 959	35 809	34 401	33 475	20 352	28 694	16 104	43 626
US Sales	490 477	462 345	338 492	315 940	291 658	284 819	355 306	343 003	380 033	379 506
Other Sales	8 660	7 410	2 258	1 618	682	4 973	8 722	6 468	5 688	572
Transmission Credits	15 772	19 927	17 710	16 402	17 559	18 307	18 021	17 443	22 140	23 841
Renewable Energy Certificates	-	1 601	1 076	1 116	2 032	1 942	3 494	3 045	2 299	2 193
US	514 909	491 283	359 536	335 076	311 931	310 042	385 543	369 959	410 160	406 112
Merchant (IESO & MISO)*	71 537	85 974	26 146	27 422	16 712	9 116	33 287	10 239	7 893	-
Total Extraprovincial Revenue	$ 624 971	$ 622 646	$ 426 641	$ 398 307	$ 363 044	$ 352 633	$ 439 182	$ 408 892	$ 434 157	$ 449 738
Water Rentals and Assessments	(134 887)	(176 383)	(103 973)	(106 169)	(145 632)	(133 292)	(125 517)	(124 469)	(122 847)	(112 167)
Fuel and Power Purchased	(123 767)	(123 000)	(121 033)	(120 163)	(119 301)	(117 864)	(177 113)	(134 189)	(130 432)	(190 933)
Net Extraprovincial Revenue	$ 366 316	$ 323 263	$ 201 635	$ 171 974	$ 98 111	$ 101 477	$ 136 552	$ 150 234	$ 180 878	$ 146 637

*IESO = Independent Electricity Systems Operator and MISO = Midcontinent Independent System Operator

Section:	Tab 3: Section 3.0 Tab 5: Schedule 5.1.2 p.10	**Page No.:**	2
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a comparison of (a) with the forecast provided in IFF11-2, indicating the changes to both actual numbers and forecast amounts.

RATIONALE FOR QUESTION:

The information is required to examine changes to export revenue forecasts.

RESPONSE:

Manitoba Hydro has received clarification from PUB advisors that the comparison requested in this information request is to IFF12. Please see the table below that compares 2012/13 and 2013/14 actuals vs. MH12 and 2014/15–2016/17 MH14 vs. MH12.

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE
Actuals vs MH 12 & MH14 vs MH12

	2012/13 Actual	2012/13 MH12	Difference	2013/14 Actual	2013/14 MH12	Difference	2014/15 MH14	2014/15 MH12	Difference	2015/16 MH14	2015/16 MH12	Difference	2016/17 MH14	2016/17 MH12	Difference
Canadian Sales	33 353	28 318	5 035	20 392	20 902	(510)	28 748	22 169	6 579	16 104	24 667	(8 564)	43 626	27 638	15 988
Other Sales	122	3 880	(3 758)	(40)	-	(40)	(54)	-	(54)	-	-	-	-	-	-
Canadian	33 475	32 198	1 277	20 352	20 902	(550)	28 694	22 169	6 525	16 104	24 667	(8 564)	43 626	27 638	15 988
US Sales	284 819	297 034	(12 215)	355 306	299 411	55 895	343 003	300 205	42 797	380 033	334 016	46 018	379 506	356 351	23 155
Other Sales	4 973	1 111	3 862	8 722	1 012	7 710	6 468	1 061	5 407	5 688	1 091	4 597	572	1 121	(550)
Transmission Credits	18 307	17 158	1 149	18 021	16 738	1 283	17 443	18 158	(715)	22 140	18 666	3 474	23 841	19 187	4 654
Renewable Energy Certificates	1 942	2 076	(134)	3 494	1 736	1 758	3 045	1 846	1 199	2 299	1 898	401	2 193	1 951	242
US	310 042	317 379	(7 337)	385 543	318 897	66 646	369 959	321 271	48 688	410 160	355 670	54 490	406 112	378 610	27 502
Merchant (IESO & MISO)*	9 116	7 405	1 711	33 287	4 685	28 602	10 239	-	10 239	7 893	-	7 893	-	-	-
Total Extraprovincial Revenue	$ 352 633	$ 356 982	$ (4 349)	$ 439 182	$ 344 484	$ 94 698	$ 408 892	$ 343 440	$ 65 452	$ 434 157	$ 380 338	$ 53 819	$ 449 738	$ 406 248	$ 43 490
Water Rentals and Assessments	(133 292)	(117 040)	(16 252)	(125 517)	(115 791)	(9 726)	(124 469)	(111 602)	(12 867)	(122 847)	(111 785)	(11 062)	(112 167)	(111 975)	(192)
Fuel and Power Purchased	(117 864)	(142 906)	25 042	(177 113)	(166 203)	(10 910)	(134 189)	(179 164)	44 975	(130 432)	(190 955)	60 523	(190 933)	(206 100)	15 167
Net Extraprovincial Revenue	$ 101 477	$ 97 036	$ 4 441	$ 136 552	$ 62 490	$ 74 062	$ 150 234	$ 52 674	$ 97 560	$ 180 878	$ 77 598	$ 103 280	$ 146 637	$ 88 173	$ 58 464

Section:	Tab 3: Section 3.0 Tab 5: Schedule 5.1.2 p.10	Page No.:	2
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate the annual and cumulative change in gross and net export revenue forecasts between IFF09 and IFF14.

RATIONALE FOR QUESTION:

The information is required to examine changes to export revenue forecasts.

RESPONSE:

Manitoba Hydro has received agreement from PUB advisors that the comparisons can be provided against IFF12. As such, this question provides a comparison to IFF12.

Gross and Net Extraprovincial Revenues have decreased significantly from IFF12 to IFF14. Over the forecast period from 2014/15 to 2031/32, the cumulative change in forecasted gross export revenue in IFF14 is $1.4 billion compared to IFF12 and the cumulative change in net export revenue is $1.0 billion.

The following schedule provides annual changes in Gross and Net Extraprovincial Revenues between MH14 and MH12.

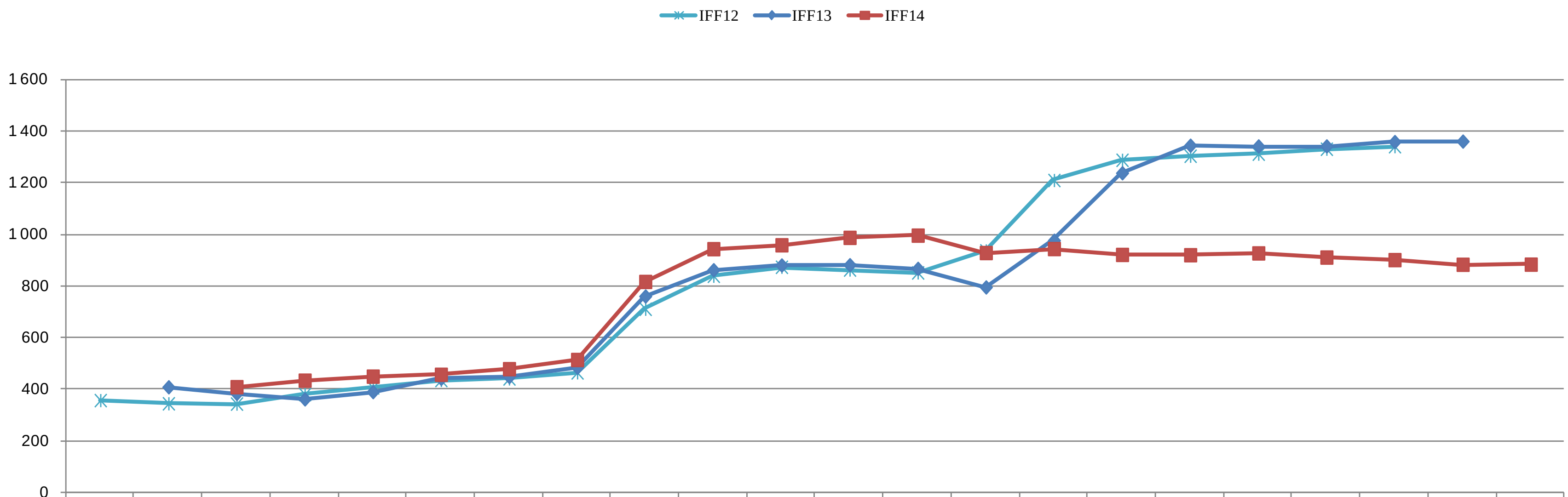
Gross Extraprovincial Revenue

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
IFF14	409	434	450	457	479	514	817	943	959	987	996	928	944	921	920	927	911	901
IFF12	343	380	406	435	441	464	711	839	873	863	851	937	1 209	1 288	1 304	1 312	1 331	1 341
Annual Change	65	54	43	22	38	50	106	105	85	125	144	(8)	(266)	(367)	(384)	(384)	(420)	(439)
Cumulative Change	65	119	163	185	223	273	379	483	569	693	838	829	564	197	(186)	(571)	(990)	(1 430)

Net Extraprovincial Revenue

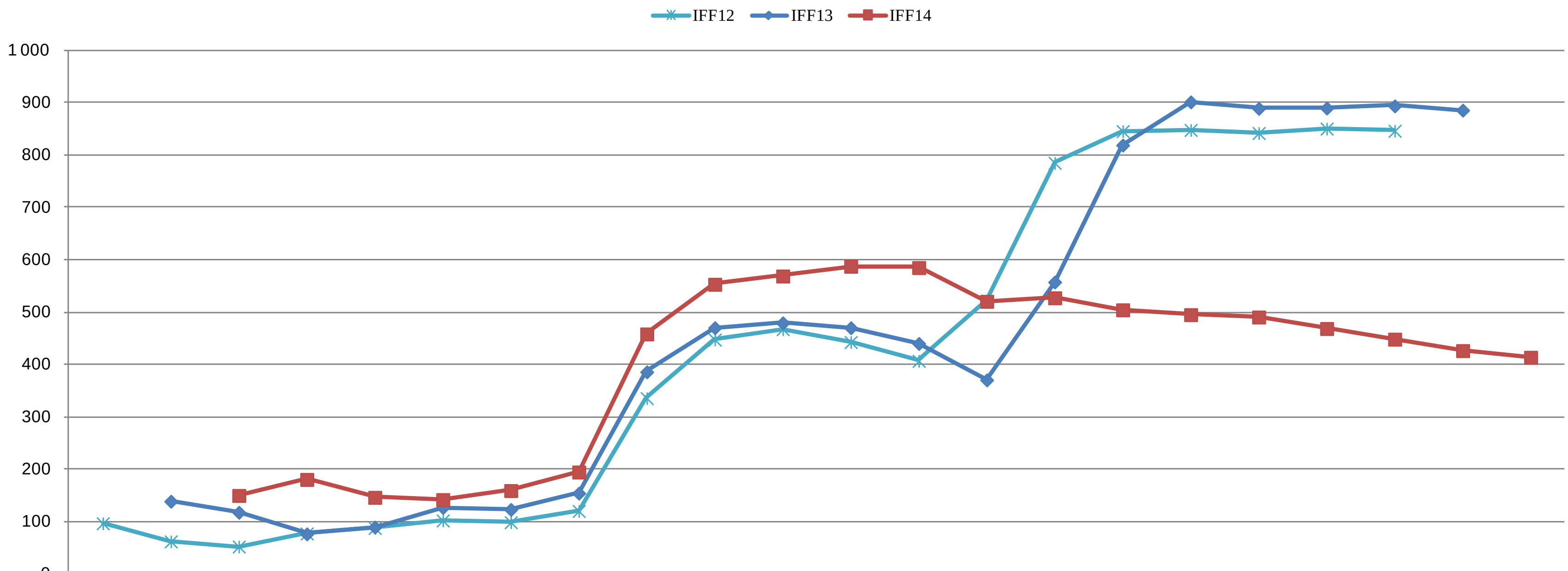
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
IFF14	150	181	147	142	160	195	459	554	569	588	586	521	528	505	496	491	469	449
IFF12	53	78	88	102	99	121	336	448	468	443	407	522	786	846	848	843	851	847
Annual Change	98	103	58	40	60	74	123	106	101	145	178	(1)	(258)	(341)	(353)	(351)	(382)	(398)
Cumulative Change	98	201	259	299	360	434	557	662	764	908	1 087	1 086	828	487	134	(217)	(599)	(997)

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

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

Section:	Tab 3: Section 3.1	**Page No.:**	2
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Key Financial Risks		
Issue:	Credit Rating of Province of Manitoba & Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file any analyses undertaken by Manitoba Hydro or third parties that address the impact of a provincial credit rating downgrade on Manitoba Hydro's borrowing costs.

b) Would projected losses of approximately $1B over ten years impact the credit rating of the Province of Manitoba?

c) What would such impacts mean for Manitoba Hydro and the taxpayer of Manitoba?

RATIONALE FOR QUESTION:

This Information Request seeks to quantify the impact of a downgrade to the Province's credit rating, which Manitoba Hydro has identified as a risk factor.

RESPONSE:

<u>Response to part a)</u>

Manitoba Hydro receives long term debt advances and a flow through credit rating from the Province of Manitoba. Definitive analysis to address the impact of a potential provincial credit rating downgrade on Manitoba Hydro's borrowing costs and access to financing is not available.

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. Credit rating agency opinions, as an indicative proxy for the financial markets, are also complex. Care needs to be taken to avoid the oversimplification that may occur when seeking direct line linkages to specific events or actions. Occasionally, credit rating announcements may move the financial markets, but more commonly, financial markets may price in changes in creditworthiness in advance of a credit rating announcement.

The absolute level of benchmark Government of Canada (GoC) bond yields, as well as the credit spread between these GoC benchmarks and the associated provincial bonds, change dynamically in the capital markets in response to the complex interaction of financial market participants. The provincial credit spreads are also benchmarked relative to the Province of Ontario bonds as Ontario is the largest issuer of provincial bonds.

On August 18, 2014 Moody's placed the Province of Manitoba's Aa1 long term debt rating on a negative outlook.[1] Since mid-July 2014, the Province of Manitoba's provincial credit spreads relative to the Ontario provincial benchmark have weakened by 7 to 9 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.

Should the credit rating for the Province of Manitoba be downgraded, it would be anticipated that interest rates and associated finance borrowing costs for Manitoba Hydro may rise. The financial impact upon Manitoba Hydro's access to financing and borrowing costs would depend upon a number of factors, including, but not limited to:

- the financial market context in which the downgrade occurred including market tone, investor appetite and liquidity;
- the degree to which changes in the relative provincial credit spreads may have been priced into the financial market in advance of any credit rating announcement;
- which credit rating agency provided the downgrade;
- investor credit risk policy limits and credit rating requirements;
- the denomination of the issue; and
- the term to maturity of a new debt issue.

[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.

Response to part b) and c)

To the extent that Manitoba Hydro maintains its self-supporting status, the contingent liability represented by Manitoba Hydro's debt to the Province of Manitoba is low, and Manitoba Hydro's capital investment plans and capital structure should have no significant impact on the Province of Manitoba's credit rating.

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.

Credit rating agencies have not provided precise definitions of the term self-supporting when evaluating the contingent liability represented by Manitoba Hydro's debt to the Province of Manitoba. It is Manitoba Hydro's view that a useful general definition was given by Moody's in the following quote (emphasis added):

> "Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting. <u>This Crown Corporation's ability to meet its own financial obligations, without recourse to provincial subsidies</u> is a positive credit attribute for the province." [2]

The credit rating agencies each consider Manitoba Hydro's financial performance, ratios and forecasts; and each currently view Manitoba Hydro's long term debt advances from the Province of Manitoba to be self-supporting. Consequently, when assessing the Province of Manitoba's ratio of net tax-supported provincial debt as a percent of provincial GDP, the credit rating agencies exclude Manitoba Hydro's debt levels (the blue portion in the following pie chart) from the evaluation of the total provincial debt portfolio. Should Manitoba Hydro lose its self-supporting status and the contingent liability materialize, the potential impact to the Province of Manitoba and its taxpayers could be substantial.

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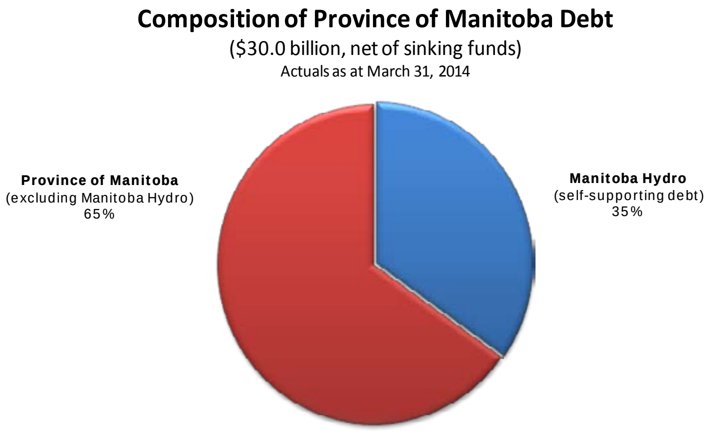
[2] Moody's Investors Service, "Credit Analysis: Province of Manitoba" dated September 5, 2012; page 3 (previously filed at the 2012/13 & 2013/14 Electric GRA in Appendix 20 Attachment 20).



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. To span across short term cash shortfalls, for example during the 2003/04 drought, Manitoba Hydro can undertake a series of actions (such as cash conservation, bridge financing and higher rate increases). Over longer periods of cash shortfalls, such as during an extended period of net losses, it would become increasingly more challenging to avoid the need for provincial subsidies, especially if the shortfalls were to occur at a vulnerable time (for example, when Manitoba Hydro's retained earnings and the equity ratio is low, and/or if the Corporation is unduly exposed to interest rate risk in a period of sharply rising interest rates).

Manitoba Hydro is of the view that the IFF14 base case, with the 3.95% rate increases, is manageable and that Manitoba Hydro's self-supporting status will be maintained. More adverse circumstances (for example with the lower rate increases such as those identified in Appendix 3.5 as scenarios A-D, or in severe drought or rising interest rates) would place significant downward pressure on the Corporation's financial health and stability.

Moving forward, Manitoba Hydro will continue to take appropriate actions to ensure it remains a self-supporting corporation and that the contingent liability represented by Manitoba Hydro's debt does not materialize. 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. As described in Tab 2 Section 2.3.6:

> "Higher rate increases in the order of 5.5% to 6.0% for the next four years would be necessary to reduce the losses that are projected in the next 10 year

> period and maintain financial reserves at current levels. This would reduce the risk of the need for larger rate increases in the event of a significant drought or adverse financial conditions. Despite these risks, Manitoba Hydro has maintained the minimum proposed rate increases at the 3.95% level in consideration of customer sensitivity to rate increases."

The credit rating agencies are aware of Manitoba Hydro's 3.95% forecasted annual rate increases and have expectations that the regulatory framework will continue to be supportive of the Corporation's rate applications.[3] The capacity to raise rates is also seen positively by credit rating agencies, for example by DBRS (see Appendix 3.8: DBRS report on Manitoba Hydro dated October 23, 2014; page 2):

> "Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened capex requirements."

Manitoba Hydro's financial strength is fundamental and Manitoba Hydro agrees with the PUB when they found the following in Orders 116/08 and 43/13:

> "It is the Board's understanding that rating agencies look prominently at MH's financial strength in assessing the credit rating of the Province. A weakening of the financial strength of MH would not be viewed favourably by those credit rating agencies and may have implications impacting the credit rating of the Province, making provincial borrowing more expensive. Such a development would not be in the public interest."[4]

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[3] As stated by Moody's:

> "Manitoba Hydro operates in a stable regulatory framework with steady yearly rate increases. It forecasts annual rate increases of 3.95% until FY2033 to contribute to replacing aging generation, transmission and distribution facilities." [report on Manitoba Hydro dated November 6, 2014 (see Appendix 3.8, or Tab 3 page 20)].

As stated by DBRS:

> "Manitoba's Public Utilities Board (PUB) has been supportive of Manitoba Hydro's rate applications and its financial targets." [page 2 of their report on the Manitoba Hydro-Electric Board dated November 28, 2011 (see Appendix 20 Attachment 4 from the 2012/13 & 2013/14 Electric GRA)].

[4] Public Utilities Board of Manitoba Order 116/08; Page 130.

"The Board notes that Manitoba Hydro shares the benefit of the flow-through credit rating of the Province, which affords it preferential interest rates on its debt and access to funds to meet its major capital spending program. However, as its debt grows, there is a potential for Manitoba Hydro's financial condition to affect the credit rating of the Province. It is important that Manitoba Hydro remains a financially strong and viable organization." [5]

[5] Public Utilities Board of Manitoba Order 43/13; Page 23.

Section:	Tab 3: Appendix 3.5	**Page No.:**	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Projected Rate Increase		
Issue:	Rate increase Alternative Scenarios		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is forecasting a deterioration of its strength with projected operating losses of almost $980 million during the forecast period.

QUESTION:

Please discuss the operating cost containment options, in priority order, that Manitoba Hydro would have to employ to eliminate 100% of the forecast deficit.

RATIONALE FOR QUESTION:

To gain an understanding of how such an operating deficit can be avoided, additional scenarios are required.

RESPONSE:

Over the 10 year forecast period Manitoba Hydro is projecting losses of approximately $900 million. As demonstrated in figure 5.5.12 (Appendix 5.5, page 14), approximately 77% of OM&A costs incurred by the corporation are for salaries, overtime and benefits and as such a significant reduction in staffing levels would be necessary in order to eliminate 100% of the forecast deficit.

The following table provides the annual EFT reductions necessary to reduce these losses for illustrative purposes only. The total reduction over the 10 year period totals over 2400 EFTs which represents a reduction of approximately 38% of the total workforce or 57% of staff required for operations & maintenance and governance, support and services functions. Staff reductions of this magnitude are not plausible as and would impair the Corporation's ability to provide safe and reliable service.

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**
Required annual reduction to OM&A	-	$ 20	$ 41	$ 64	$ 90	$ 117	$ 146	$ 177	$ 209	$ 243	
Number of EFTs to eliminate losses	-	196	212	236	250	273	288	313	321	341	2,430
% of Total Straight Time EFTs											38%
% of Total Operations & Maintenance /Govenance and Support Services EFTs											57%

Section:	Tab 3: Appendix 3.5	Page No.:	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Projected Rate Increase		
Issue:	Rate increase Alternative Scenarios		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is forecasting a deterioration of its strength with projected operating losses of almost $980 million during the forecast period.

QUESTION:

Please indicate the equal annual rate increases required to meet 100% of the net losses forecasted in the next 10 years. Please provide the IFF reflecting this scenario.

RATIONALE FOR QUESTION:

To gain an understanding of how such an operating deficit can be avoided, additional scenarios are required.

RESPONSE:

The projected losses in MH14 to 2013/24 are $900 million. The equal annual rate increase required to eliminate the net losses forecasted in the next 10 years is 5.30% beginning in 2015/16. Projected financial statements reflecting these rate increases are attached.

ELECTRIC OPERATIONS (MH14)
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	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 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	2,294	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 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	1,977	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)

Section:	Tab 3: Appendix 3.5	Page No.:	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Projected Rate Increase		
Issue:	Rate increase Alternative Scenarios		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is forecasting a deterioration of its strength with projected operating losses of almost $980 million during the forecast period.

QUESTION:

Please indicate the equal annual increases to meet 50% of the projected net loss forecast in the next 10 years. Please provide the IFF reflecting the scenario.

RATIONALE FOR QUESTION:

To gain an understanding of how such an operating deficit can be avoided, additional scenarios are required.

RESPONSE:

The projected losses in MH14 to 2023/24 are $900 million. To reduce these losses by 50% to approximately $450 million, the projected even annual rate increases required in the next 10 years from 2015/16 to 2023/24 is 4.44%. The projected financial statements reflecting these rates are attached.

ELECTRIC OPERATIONS (MH14)
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	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 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	2 597	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 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	1 965	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)

Section:	Tab 3: Appendix 3.5	**Page No.:**	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Projected Rate Increase		
Issue:	Rate increase Alternative Scenarios		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is forecasting a deterioration of its strength with projected operating losses of almost $980 million during the forecast period.

QUESTION:

Please indicate the equal annual increases to meet 75% of the projected net loss forecasted in the next 10 years. Please provide the IFF reflecting the scenario.

RATIONALE FOR QUESTION:

To gain an understanding of how such an operating deficit can be avoided, additional scenarios are required.

RESPONSE:

The projected losses in MH14 to 2023/24 are $900 million. To reduce these losses by 75% to approximately $225 million, the projected even annual rate increases required in the next 10 years from 2015/16 to 2023/24 is 4.78%. Projected financial statements reflecting these rates are attached.

ELECTRIC OPERATIONS (MH14)
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	70	143	223	306	395	487	585	691	803
BPIII Reserve Account	(30)	(33)	(34)	(37)	(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	1 939	2 033	2 140	2 278	2 425	2 824	3 057	3 191	3 344
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	546	579	745	877	1 178	1 303	1 302	1 308
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	153	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	2 041	2 311	2 460	2 905	3 128	3 210	3 262
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	128	85	106	(27)	(31)	(70)	(70)	(20)	79
* Additional General Consumers Revenue										
Percent Increase	0.00%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%	4.78%
Cumulative Percent Increase	0.00%	4.78%	9.79%	15.03%	20.53%	26.29%	32.33%	38.65%	45.28%	52.23%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	14%	14%	12%	12%	13%
Interest Coverage	1.16	1.18	1.10	1.10	0.98	0.97	0.95	0.95	0.98	1.06
Capital Coverage	0.98	1.04	0.98	1.17	0.99	0.96	1.00	1.18	1.39	1.58

ELECTRIC OPERATIONS (MH14)
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	2 597	2 726	2 167	2 233	2 435
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	27 667	28 298	27 727	27 783	27 959
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	20 977	21 706	22 392	22 355	22 650	22 641
Current and Other Liabilities	2 016	2 139	2 057	2 987	2 268	2 624	2 667	2 233	1 985	2 054
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	116	152	164	109	55	-	-	-
Retained Earnings	2 717	2 790	2 876	2 982	2 955	2 924	2 854	2 783	2 763	2 842
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 667	28 298	27 727	27 783	27 959

ELECTRIC OPERATIONS (MH14)
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	1 970	2 065	2 174	2 287	2 423	2 822	3 055	3 188	3 341
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 070)	(1 100)	(1 126)	(1 155)
Interest Paid	(511)	(514)	(543)	(592)	(779)	(917)	(1 209)	(1 326)	(1 297)	(1 299)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	599	600	640	543	525	574	657	780	902
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 590	1 600	1 390	400	560	380
Sinking Fund Withdrawals	110	21	-	7	448	203	292	715	165	22
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	1 813	1 469	731	372	243	80
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)	(244)	(261)	(358)	(247)	(252)
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)	(976)	(979)
Net Increase (Decrease) in Cash	(270)	(66)	114	(12)	(159)	166	5	(116)	47	3
Cash at Beginning of Year	133	(137)	(203)	(89)	(100)	(259)	(94)	(89)	(205)	(158)
Cash at End of Year	(137)	(203)	(89)	(100)	(259)	(94)	(89)	(205)	(158)	(155)

Section:	Tab 3: Figure 3.3	**Page No.:**	8
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Operating Results		
Issue:	Operating Result Shortfall		

PREAMBLE TO IR (IF ANY):

QUESTION:

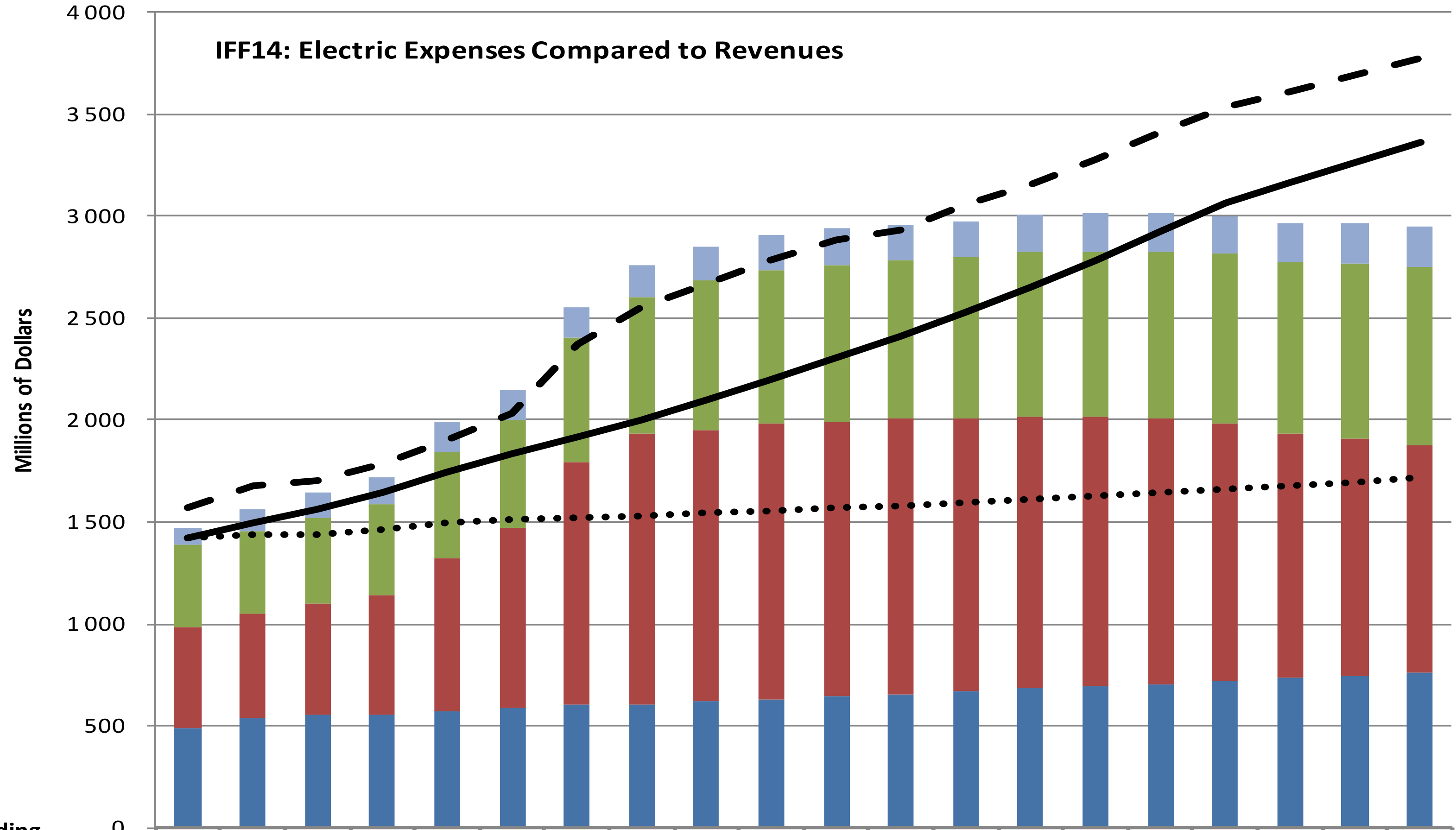
Please provide Figure 3.3 updated through 2034 with a table of corresponding data points.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the impact of changes in assumptions / risk factors on projected revenue shortfalls.

RESPONSE:

Please see the following figure and corresponding table of data points.



Fiscal Year Ending	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Taxes and Other	85	106	124	138	149	151	145	161	162	175	178	175	177	180	183	186	188	193	198	201
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752	767	780	791	804	811	820	831	842	857	873
Finance Expense	495	510	548	581	752	887	1 194	1 326	1 334	1 349	1 351	1 348	1 338	1 337	1 321	1 301	1 263	1 197	1 161	1 116
Operating and Administrative	486	542	552	557	571	585	601	607	619	631	644	657	669	683	697	706	719	733	748	763
GCR incl Additional	1 422	1 493	1 558	1 644	1 744	1 837	1 915	2 000	2 096	2 195	2 302	2 414	2 531	2 654	2 782	2 922	3 069	3 164	3 262	3 365
GCR incl Additional + Net Extraprov	1 572	1 674	1 705	1 786	1 903	2 032	2 374	2 554	2 665	2 783	2 887	2 935	3 059	3 159	3 278	3 413	3 538	3 612	3 689	3 779
GCR at PUB approved rates	1 422	1 436	1 440	1 461	1 494	1 516	1 521	1 529	1 541	1 554	1 568	1 582	1 597	1 611	1 625	1 642	1 660	1 678	1 696	1 716

Section:	Tab 3: Figure 3.3	Page No.:	8
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Operating Results		
Issue:	Operating Result Shortfall		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a similar chart to Figure 3.3 that includes the IFF13-1 assumptions and compares them to the IFF14 assumptions.

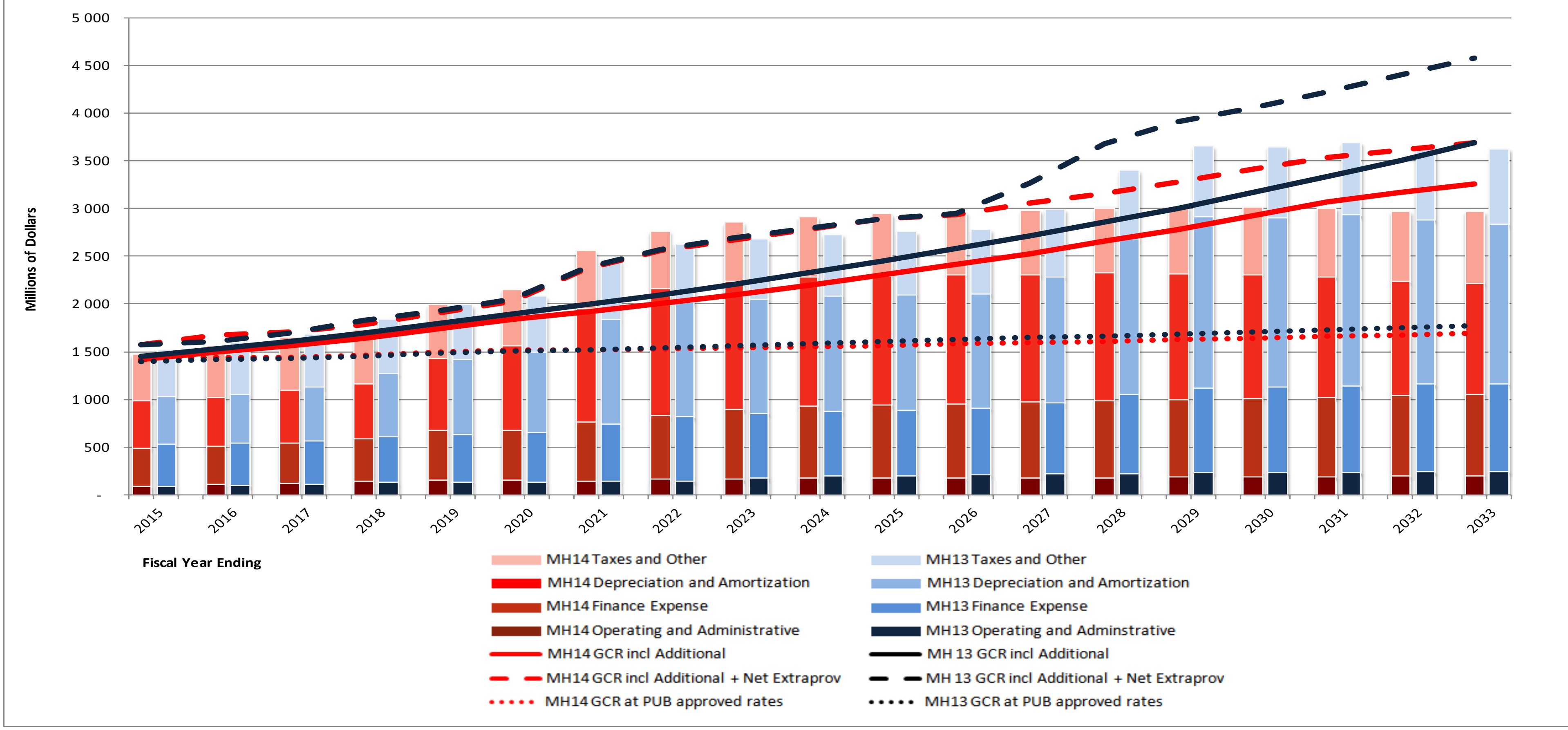
RATIONALE FOR QUESTION:

This Information Request seeks to explore the impact of changes in assumptions / risk factors on projected revenue shortfalls.

RESPONSE:

Please see the following figure showing both IFF14 and IFF13.

Electric Expenses Compared to Revenues



Section:	Tab 3: Figure 3.3	**Page No.:**	8
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Operating Results		
Issue:	Operating Result Shortfall		

PREAMBLE TO IR (IF ANY):

QUESTION:

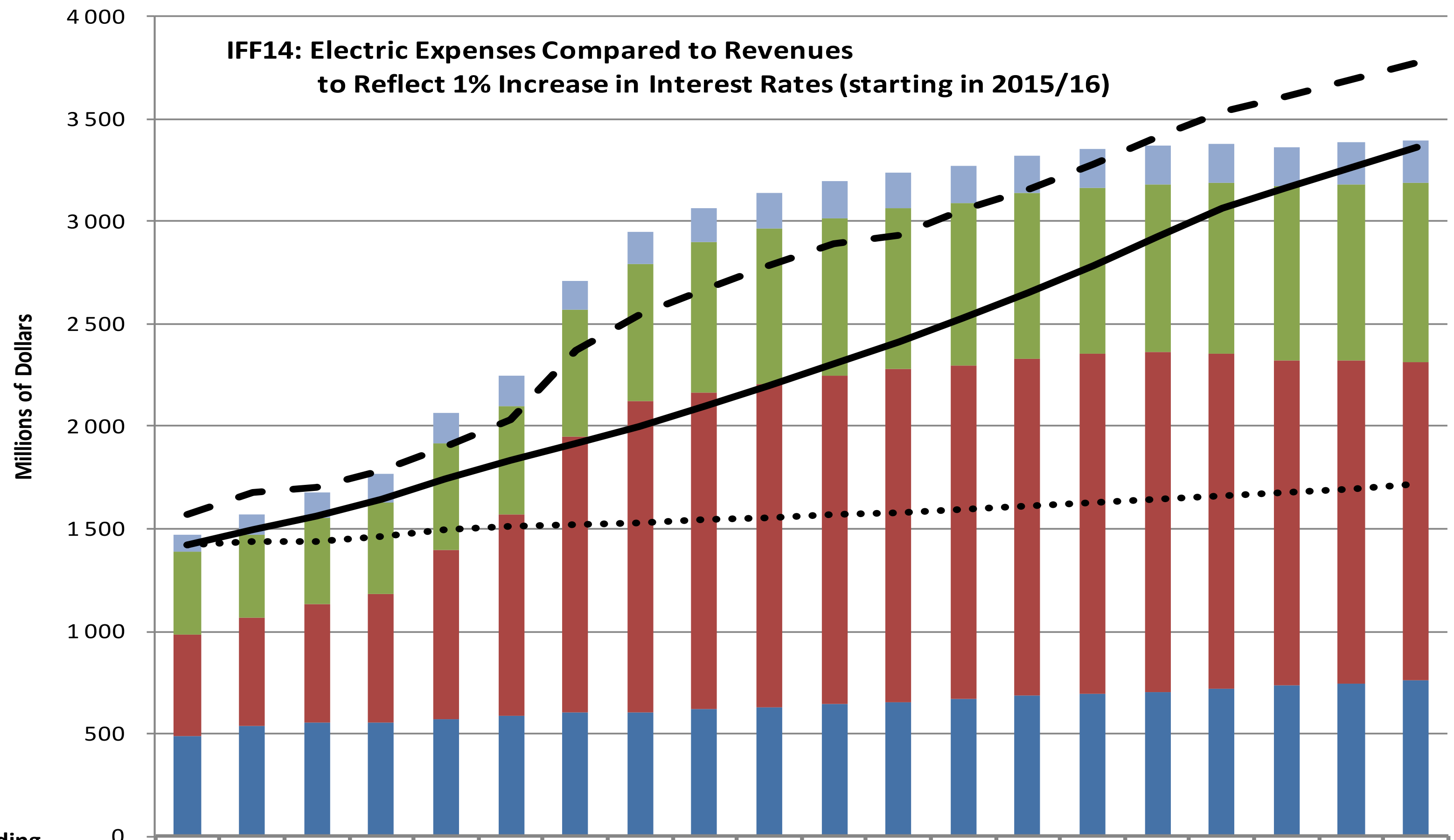
Please revise the chart provided in answer to (a) to reflect a 1% increase in interest rates over the assumed values commencing in 2017/18.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the impact of changes in assumptions / risk factors on projected revenue shortfalls.

RESPONSE:

IFF14 includes an interest rate sensitivity to reflect a 1% increase in interest rates on short-term, long-term, floating rate debt, and as well as sinking funds. This analysis commences in 2015/16. Please see the following figure and table of data points for results of the 1% increase in interest rate sensitivity.



Fiscal Year Ending	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Taxes and Other	85	105	123	138	149	150	139	159	160	174	178	175	178	181	184	187	190	194	201	204
Depreciation and Amortization	405	401	423	446	522	526	615	670	740	756	771	784	795	808	816	825	835	847	861	878
Finance Expense	495	526	577	625	824	985	1 352	1 517	1 545	1 577	1 603	1 622	1 629	1 649	1 655	1 654	1 635	1 591	1 573	1 552
Operating and Administrative	486	542	552	557	571	585	601	607	619	631	644	657	669	683	697	706	719	733	748	763
GCR incl Additional	1 422	1 493	1 558	1 644	1 744	1 837	1 915	2 000	2 096	2 195	2 302	2 414	2 531	2 654	2 782	2 922	3 069	3 164	3 262	3 365
GCR incl Additional + Net Extraprov	1 572	1 674	1 705	1 786	1 903	2 032	2 374	2 548	2 665	2 783	2 888	2 935	3 059	3 159	3 278	3 413	3 538	3 613	3 689	3 779
GCR at PUB approved rates	1 422	1 436	1 440	1 461	1 494	1 516	1 521	1 529	1 541	1 554	1 568	1 582	1 597	1 611	1 625	1 642	1 660	1 678	1 696	1 716

Section:	Tab 3: Figure 3.3	Page No.:	8
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Operating Results		
Issue:	Operating Result Shortfall		

PREAMBLE TO IR (IF ANY):

QUESTION:

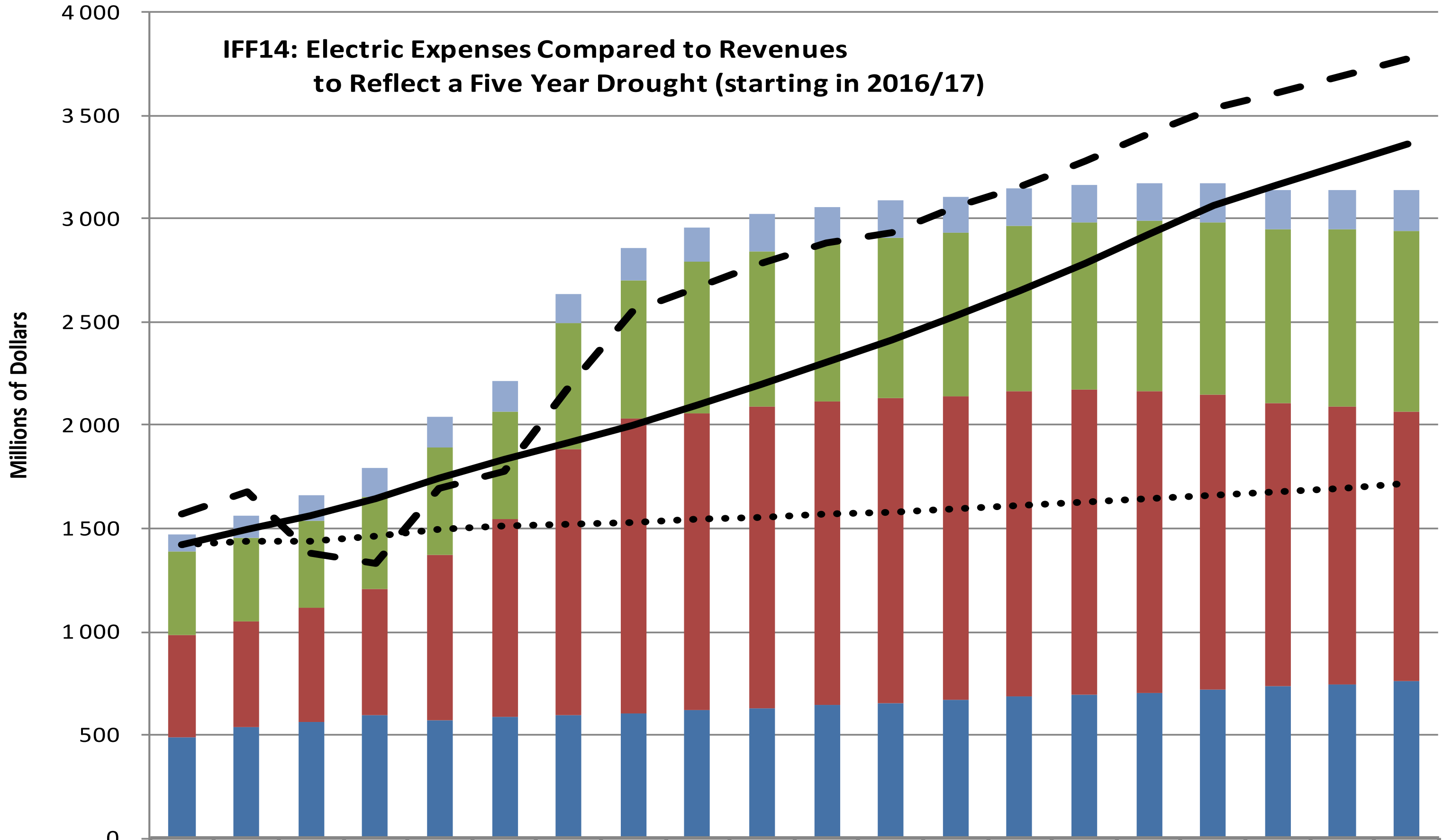
Please revise the chart provided in answer to (a) to reflect a five year drought commencing in 2017/18 demonstrating the impact on Manitoba Hydro.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the impact of changes in assumptions / risk factors on projected revenue shortfalls.

RESPONSE:

IFF14 includes a five year drought sensitivity and this analysis commences in 2016/17. Please see the following figure and table of data points for results of the drought sensitivity.



Fiscal Year Ending	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Taxes and Other	85	106	124	138	149	150	142	158	159	174	178	175	177	180	183	185	188	193	198	201
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752	767	780	791	804	811	820	831	842	857	873
Finance Expense	495	510	552	609	806	958	1 283	1 427	1 441	1 462	1 472	1 476	1 472	1 480	1 473	1 460	1 430	1 370	1 341	1 302
Operating and Administrative	486	542	562	599	568	584	599	607	619	631	644	657	669	683	697	706	719	733	748	763
GCR incl Additional	1 422	1 493	1 558	1 644	1 744	1 837	1 915	2 000	2 096	2 195	2 302	2 414	2 531	2 654	2 782	2 922	3 069	3 164	3 262	3 365
GCR incl Additional + Net Extraprov	1 572	1 674	1 382	1 327	1 695	1 780	2 193	2 554	2 665	2 783	2 887	2 935	3 059	3 159	3 278	3 413	3 538	3 613	3 689	3 776
GCR at PUB approved rates	1 422	1 436	1 440	1 461	1 494	1 516	1 521	1 529	1 541	1 554	1 568	1 582	1 597	1 611	1 625	1 642	1 660	1 678	1 696	1 716

Section:	Tab 3: Figure 3.3	**Page No.:**	8
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Operating Results		
Issue:	Operating Result Shortfall		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a breakdown of the forecast $2 billion reduction in export revenues attributable to Conawapa and to lower export prices

RATIONALE FOR QUESTION:

This Information Request seeks to explore the impact of changes in assumptions / risk factors on projected revenue shortfalls.

RESPONSE:

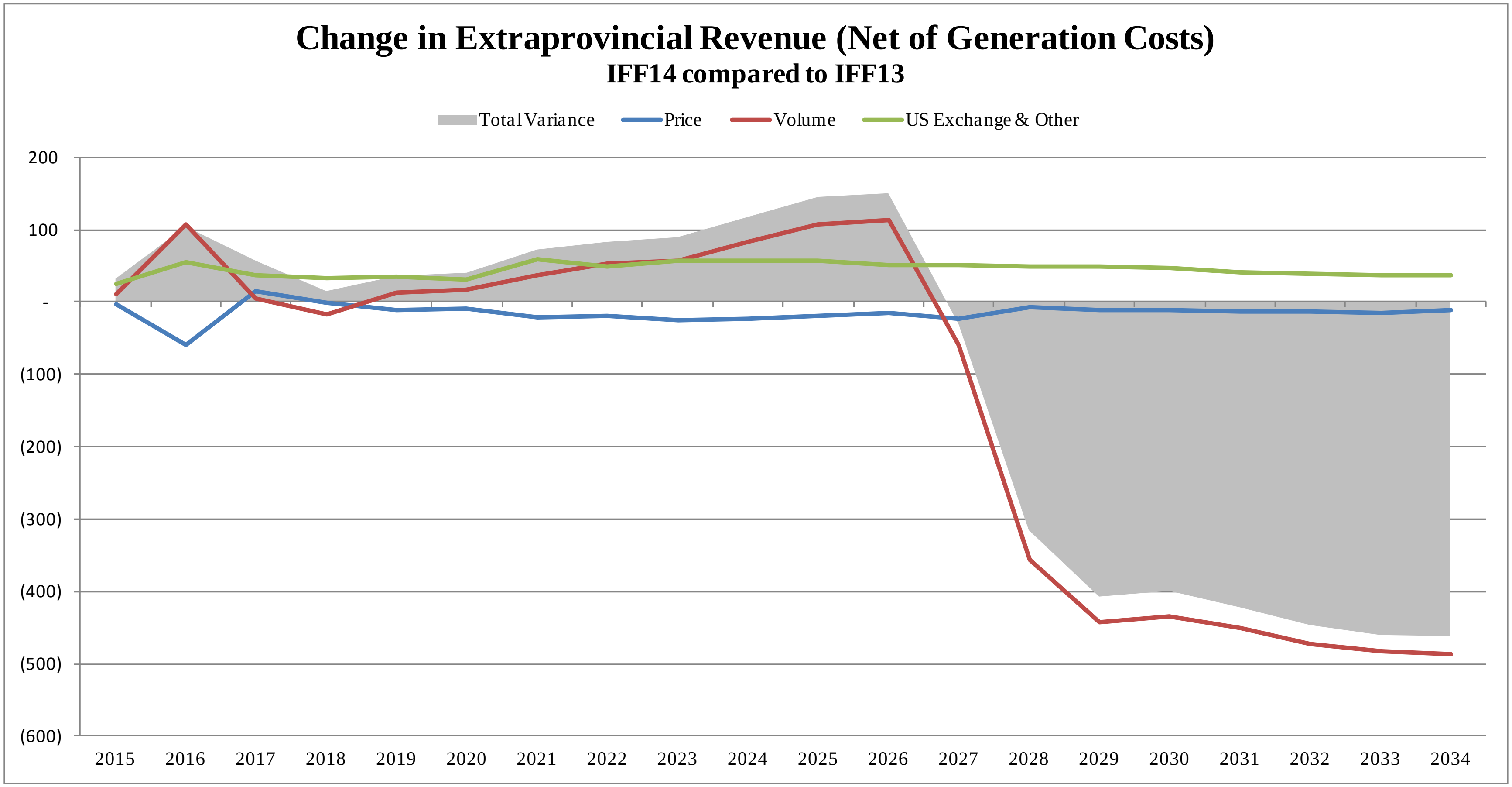
The following figure and schedule provide the change in net extraprovincial revenues (net of water rentals and fuel and power purchases) from IFF13 to IFF14 due to changes in price, volume and US exchange and other.

The projected $2 billion reduction in net extraprovincial revenues is due to lower forecast volume of energy available for export ($2.6 billion) and lower forecast electricity export prices ($0.3 billion), partially offset by a weakening of the Canadian dollar ($0.9 billion increase) compared to IFF13. The reduction in volume is due mainly to the suspension of Conawapa, partially offset by higher volumes of energy available for export as a result of a reduction in the Manitoba domestic load forecast through increased DSM programs.

The weakening of the Canadian dollar in IFF14 results in higher net extraprovincial revenues compared to IFF13. However, the increase in net extraprovincial revenues due the US exchange rate are largely offset by corresponding increases in the exchange on US interest and other payments.

Relative Impacts of Changes in Price, Volume, and US Exchange on IFF14 Extraprovincial Revenues Compared to IFF13

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Price	(4)	(58)	14	(1)	(11)	(8)	(22)	(18)	(26)	(22)	(18)	(16)	(23)	(8)	(12)	(11)	(13)	(12)	(14)	(11)	(295)
Volume	11	107	5	(17)	13	17	36	53	58	82	107	114	(59)	(356)	(443)	(436)	(450)	(473)	(483)	(487)	(2 600)
US Exchange & Other	25	56	38	33	34	32	58	49	58	57	57	52	52	50	49	48	41	40	38	36	900
Total	32	104	57	15	36	40	72	83	89	117	145	150	(30)	(315)	(406)	(398)	(421)	(446)	(459)	(461)	(1 995)



Section:	Tab 3: Appendix 3.7	**Page No.:**	3
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Debt Management		
Issue:	Growth in Debt Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide an updated Chart 1 including accumulated capitalized interest, in similar detail as PUB/MH I-101 (NFAT). Please provide a table of corresponding data points.

RATIONALE FOR QUESTION:

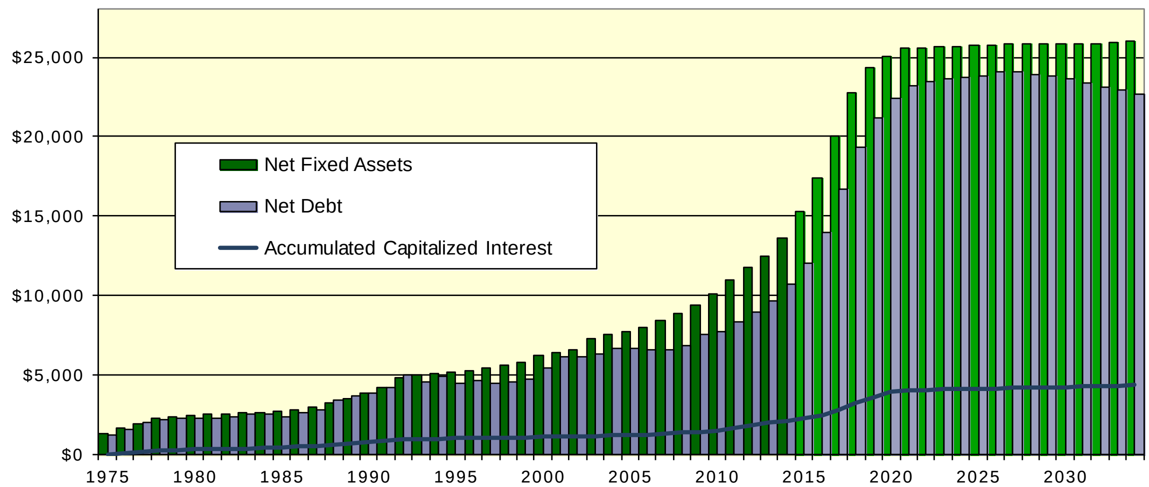
This Information Request seeks to visualize gross debt accumulation over the forecast timeframe.

RESPONSE:

The chart in PUB/MH I-101 from the 2012/13 & 2013/14 GRA depicted the consolidated net fixed assets and net long term debt information (with actual values for the fiscal years ending 1990 - 2012, and forecast IFF11-2 values for fiscal years ending 2013 - 2032). Net assets are the total property, plant and equipment less accumulated depreciation plus construction work in progress. Net long term debt is gross debt less sinking funds/ investments (accumulated capitalized interest is not used in the calculation of gross or net debt levels).

Chart 1 from the Debt Management Strategy in Appendix 3.7 updated the aforementioned consolidated net fixed assets and net long term debt information (with actual values going back to fiscal year ending 1975 updated to 2014, and updated IFF14 forecast values for the fiscal years ending 2015 to 2034). This chart and the corresponding data points (with accumulated capitalized interest commencing in 1975) are as follows:

Chart 1: **Manitoba Hydro**
Net Fixed Assets & Net Debt
(Actuals to March 31, 2014 in millions of dollars at fiscal year ending)



Fiscal Year Ending	Net Assets	Net Long Term Debt	Accumulated Capitalized Interest
1975	1,336	1,225	50
1976	1,656	1,616	98
1977	1,972	1,990	160
1978	2,259	2,168	234
1979	2,413	2,331	292
1980	2,489	2,271	320
1981	2,529	2,298	342
1982	2,569	2,373	368
1983	2,632	2,541	397
1984	2,685	2,528	429
1985	2,731	2,423	468
1986	2,856	2,603	502
1987	3,015	2,805	547
1988	3,242	3,443	605
1989	3,541	3,656	681
1990	3,882	3,889	778
1991	4,267	4,199	888
1992	4,857	4,972	960
1993	4,983	4,533	993
1994	5,067	4,948	1,009
1995	5,170	4,508	1,023
1996	5,310	4,685	1,042
1997	5,464	4,493	1,058
1998	5,608	4,559	1,077
1999	5,774	4,772	1,097
2000	6,235	5,488	1,112
2001	6,428	6,114	1,128
2002	6,626	6,146	1,154
2003	7,305	6,320	1,182
2004	7,536	6,675	1,213

Fiscal Year Ending	Net Assets	Net Long Term Debt	Accumulated Capitalized Interest
2005	7,776	6,642	1,246
2006	8,010	6,614	1,281
2007	8,415	6,597	1,328
2008	8,912	6,852	1,388
2009	9,382	7,521	1,444
2010	10,128	7,716	1,543
2011	10,954	8,365	1,681
2012	11,797	9,011	1,851
2013	12,508	9,634	1,992
2014	13,627	10,757	2,134
2015	15,258	12,034	2,279
2016	17,387	13,983	2,486
2017	20,069	16,694	2,802
2018	22,763	19,342	3,239
2019	24,324	21,168	3,627
2020	25,081	22,409	3,968
2021	25,588	23,205	4,080
2022	25,608	23,503	4,092
2023	25,645	23,615	4,106
2024	25,664	23,747	4,123
2025	25,725	23,837	4,143
2026	25,776	24,089	4,167
2027	25,814	24,083	4,192
2028	25,831	23,866	4,209
2029	25,851	23,839	4,229
2030	25,836	23,605	4,249
2031	25,851	23,367	4,273
2032	25,862	23,154	4,298
2033	25,901	22,933	4,326
2034	26,006	22,705	4,363

Section:	Tab 3: Appendix 3.7	**Page No.:**	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Interest Rate Forecast		
Issue:	Weighted Average Interest Rate		

PREAMBLE TO IR (IF ANY):

The majority of Manitoba Hydro's capital spending over the next five years will be debt-financed. Manitoba Hydro has provided interest rate forecasts with September and October 2014 vintages.

QUESTION:

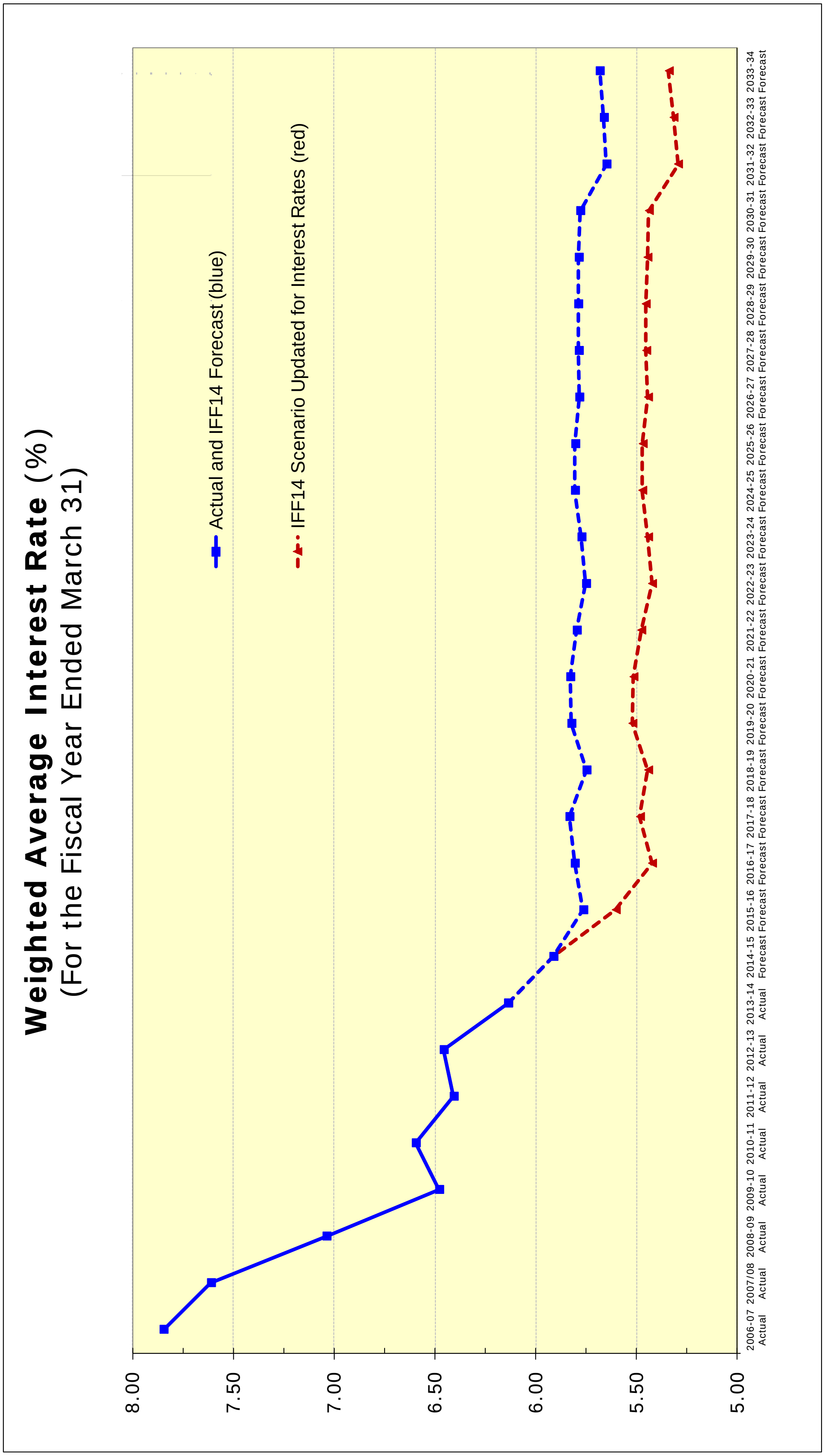
Please extend the weighted average interest rate chart in Appendix 3.7 to 2019/20 based on the historical interest rate projections used for the table.

RATIONALE FOR QUESTION:

To gain an understanding of the financial exposure of the planned capital spending.

RESPONSE:

Please see the following chart which provides the weighted average interest rate chart (as previously shown as Chart 5 in Appendix 3.7) extended to 2033/34 for IFF14 and the IFF14 scenario updated for interest rates as filed in response to PUB/MH-I-10b.


Weighted Average Interest Rate (%)
(For the Fiscal Year Ended March 31)
Actual and IFF14 Forecast (blue)
IFF14 Scenario Updated for Interest Rates (red)
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

Section:	Tab 3: Appendix 3.7	**Page No.:**	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Interest Rate Forecast		
Issue:	Weighted Average Interest Rate		

PREAMBLE TO IR (IF ANY):

The majority of Manitoba Hydro's capital spending over the next five years will be debt-financed. Manitoba Hydro has provided interest rate forecasts with September and October 2014 vintages.

QUESTION:

Please update the forecast based on more current interest rate forecasts for both long and short term interest rates.

RATIONALE FOR QUESTION:

To gain an understanding of the financial exposure of the planned capital spending.

RESPONSE:

The January 2015 update to the interest rate forecast can be found in the response to PUB/MH-I-75c. The MH14 scenario incorporating this updated interest rate forecast is found as Attachment A.

It is important to recognize that this scenario would not occur in isolation of other economic outcomes that may affect the Corporation's financial performance and therefore the scenario in Appendix A is not a representative update to the Corporation's revenue requirement.

Manitoba Hydro operates in a complex economic environment that simultaneously affects many parts of its operations. The economy's impact upon Manitoba Hydro's revenue requirement is not exclusively seen through changing interest rates and the evolving views of Manitoba Hydro's external interest rate forecasters. There are numerous counterbalances.

For example, the low interest rate environment has provided an opportunity for Manitoba Hydro, on behalf of its ratepayers, to beneficially reduce its weighted average interest rate on its debt portfolio (please see PUB/MH-I-10a). However, at the same time that Manitoba Hydro experiences lower interest rates, the Corporation is also experiencing factors that are contributing to lower energy prices. One of the factors cited by the Bank of Canada for its January 21, 2015 action to lower the target overnight interest rate was the “unambiguously negative impact on the Canadian economy” of lower oil prices.

Natural gas prices are a significant factor driving electricity prices in the export market. There are numerous factors that underlie natural gas prices, such as oil and natural gas production growth, electricity demand growth and political events (related to OPEC). These factors are currently resulting in a continued commodity oversupply relative to demand, driving down natural gas prices which is then having a downward impact on the electricity export market. As a result, Manitoba Hydro expects that export revenue projections will be reduced from those provided for IFF14 largely offsetting the impact of lower interest rates on Manitoba Hydro’s overall revenue requirements.

In order for the PUB to see a more representative and balanced outlook of Manitoba Hydro’s electric operations, Manitoba Hydro has provided an additional MH14 scenario that shows the combined effects of updated interest rates along with estimated reductions in export revenue (see Attachment B). The following table demonstrates that the cumulative net income to 2016/17 is $6 million lower when simultaneously updated with both interest rates and extra-provincial revenues.

Fiscal Year	**MH14 Net Income** base case	**MH14 Net Income** Appendix A (Scenario updating interest rates only)	**MH14 Net Income** Appendix B (Scenario updating interest rates and extra-provincial revenues)
2014/15	102	102	102
2015/16	115	128	101
2016/17	59	89	67
TOTAL	**276**	**319**	**270**
Diff from Base		43	**(6)**

Manitoba Hydro periodically updates its financial projections to reflect a wide range of updated information. However, these updates need to be viewed in context with the underlying need for electricity rate increases. As discussed in Tab 2 of the Application, a large portion of the revenue requirements are associated with the magnitude of the capital assets being placed into service over the next forecast period. Manitoba Hydro's financial strength provides the means to smooth out short term volatility in costs and revenues to provide customers with rate stability. Isolating the impacts of changes, beneficial or adverse, in any one input variable has the potential to create a spurious forecast, and add undue rate variability and/or to alter the longer term progress towards the achievement of Manitoba Hydro's financial targets.

ELECTRIC OPERATIONS
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	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	542	552	557	571	585	601	607	619	631
Finance Expense	495	497	518	551	712	836	1 119	1 229	1 231	1 240
Depreciation and Amortization	405	401	422	445	521	524	612	665	735	751
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	133
Fuel and Power Purchased	134	130	191	202	207	205	234	260	257	267
Capital and Other Taxes	99	107	120	134	143	144	145	151	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	1 811	1 926	2 013	2 277	2 420	2 845	3 050	3 137	3 194
Non-controlling Interest	25	12	7	7	5	3	7	0	(1)	(3)
Net Income	102	128	89	95	(50)	(65)	(106)	(106)	(84)	(14)
* 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%	14%	13%	12%	12%	12%
Interest Coverage	1.16	1.19	1.11	1.10	0.95	0.94	0.91	0.91	0.93	0.99
Capital Coverage	0.98	1.03	0.98	1.15	0.95	0.92	0.94	1.12	1.27	1.41

ELECTRIC OPERATIONS
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	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	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 239	1 230	1 214	1 208	1 188	1 161	1 122	1 050	1 012	970
Depreciation and Amortization	766	779	790	803	810	819	830	841	855	871
Water Rentals and Assessments	133	133	133	134	134	135	135	136	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	167	168	169	171	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
	3 233	3 246	3 264	3 286	3 296	3 299	3 290	3 256	3 252	3 256
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	60	95	208	284	400	540	678	794	877	973
* 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	12%	13%	14%	15%	17%	19%	22%	25%	29%	33%
Interest Coverage	1.05	1.08	1.17	1.23	1.33	1.46	1.59	1.74	1.84	1.97
Capital Coverage	1.44	1.50	1.67	1.78	1.89	2.15	2.24	2.40	2.49	2.61

ELECTRIC OPERATIONS
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	17 913	19 128	19 988	24 957	28 305	33 137	33 780	34 412	35 076
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 402)	(9 053)	(9 718)	(10 398)
Net Plant in Service	11 487	11 901	12 735	13 193	17 687	20 507	24 735	24 727	24 694	24 679
Construction in Progress	3 257	4 926	6 734	8 945	5 985	3 895	161	185	241	263
Current and Other Assets	1 798	1 569	1 821	2 266	2 283	2 590	2 714	2 147	2 204	2 447
Goodwill and Intangible Assets	198	186	175	165	163	171	162	146	131	115
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 860	21 779	24 922	26 515	27 583	28 205	27 637	27 685	27 902
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	20 977	21 706	22 392	22 555	22 850	23 041
Current and Other Liabilities	2 016	2 132	2 032	2 957	2 230	2 605	2 675	2 079	1 886	1 890
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	2 791	2 880	2 974	2 925	2 860	2 754	2 648	2 564	2 549
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 860	21 779	24 922	26 515	27 583	28 205	27 637	27 685	27 902

ELECTRIC OPERATIONS
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	35 756	36 478	37 344	38 058	38 793	39 489	40 229	40 984	41 757	42 886
Accumulated Depreciation	(11 092)	(11 801)	(12 526)	(13 267)	(14 022)	(14 792)	(15 575)	(16 374)	(17 188)	(18 018)
Net Plant in Service	24 664	24 677	24 818	24 791	24 771	24 698	24 654	24 611	24 569	24 867
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 359	2 536	2 958	3 273	3 636	4 126	4 123	4 928	5 755	6 641
Goodwill and Intangible Assets	101	87	73	62	51	39	28	17	5	(6)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 819	27 996	28 407	28 693	29 035	29 481	29 462	30 254	31 099	32 069
LIABILITIES AND EQUITY										
Long-Term Debt	22 795	23 398	23 601	23 543	23 476	22 749	22 739	22 743	22 737	22 381
Current and Other Liabilities	1 956	1 397	1 361	1 383	1 355	1 950	1 226	1 181	1 116	1 430
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 609	2 703	2 911	3 195	3 594	4 134	4 811	5 604	6 480	7 453
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 819	27 996	28 407	28 693	29 035	29 481	29 462	30 254	31 099	32 069

ELECTRIC OPERATIONS
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	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 100)	(1 125)	(1 156)
Interest Paid	(511)	(507)	(519)	(562)	(744)	(866)	(1 152)	(1 248)	(1 226)	(1 231)
Interest Received	13	15	20	29	33	33	30	28	14	15
	558	594	597	629	521	501	538	621	715	808
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 600	1 590	1 390	600	570	580
Sinking Fund Withdrawals	110	21	-	7	448	203	292	715	165	23
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	1 823	1 459	731	572	253	281
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributi	(1 900)	(2 513)	(3 121)	(3 229)	(2 235)	(1 528)	(1 003)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(244)	(261)	(357)	(248)	(253)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 736)	(3 309)	(3 493)	(2 497)	(1 807)	(1 294)	(1 144)	(976)	(980)
Net Increase (Decrease) in Cash	(270)	(65)	124	(7)	(153)	153	(24)	50	(9)	109
Cash at Beginning of Year	133	(137)	(202)	(78)	(85)	(238)	(85)	(109)	(59)	(68)
Cash at End of Year	(137)	(202)	(78)	(85)	(238)	(85)	(109)	(59)	(68)	41

Manitoba Hydro

ATTACHMENT A - Updated Interest Rates Only

ELECTRIC OPERATIONS
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	3 340	3 472	3 572	3 699	3 846	3 977	4 062	4 142	4 245
Cash Paid to Suppliers and Employees	(1 180)	(1 190)	(1 212)	(1 226)	(1 248)	(1 270)	(1 289)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 237)	(1 232)	(1 227)	(1 238)	(1 231)	(1 213)	(1 189)	(1 095)	(1 070)	(1 041)
Interest Received	18	20	32	44	56	64	74	55	67	80
	896	938	1 066	1 152	1 276	1 426	1 572	1 707	1 806	1 921
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	180	590	190	(10)	(10)	(30)	(30)	(10)	(40)	(30)
Sinking Fund Withdrawals	292	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)
	40	208	161	(37)	(35)	(22)	(51)	(48)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributi	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(265)	(263)	(270)	(282)	(293)	(301)	(308)	(286)	(296)	(307)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 039)	(1 044)	(1 048)	(1 053)	(1 081)	(1 075)	(1 121)	(1 112)	(1 169)	(1 261)
Net Increase (Decrease) in Cash	(103)	101	180	62	159	330	400	547	590	615
Cash at Beginning of Year	41	(62)	39	218	281	440	770	1 170	1 717	2 307
Cash at End of Year	(62)	39	218	281	440	770	1 170	1 717	2 307	2 921

ELECTRIC OPERATIONS
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	402	426	434	455	487	771	895	909	936
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 895	1 984	2 078	2 198	2 325	2 686	2 896	3 005	3 131
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	497	520	553	716	841	1 127	1 240	1 244	1 257
Depreciation and Amortization	405	401	422	445	521	524	612	665	735	751
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	133
Fuel and Power Purchased	134	125	187	197	202	200	227	252	249	258
Capital and Other Taxes	99	107	121	134	143	144	144	151	151	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	1 806	1 924	2 011	2 277	2 420	2 846	3 052	3 141	3 201
Non-controlling Interest	25	12	7	7	5	3	7	0	(1)	(3)
Net Income	102	101	67	74	(73)	(92)	(153)	(156)	(137)	(73)
* 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%	13%	11%	11%	11%
Interest Coverage	1.16	1.14	1.08	1.08	0.93	0.92	0.88	0.87	0.89	0.94
Capital Coverage	0.98	0.98	0.94	1.11	0.91	0.86	0.87	1.03	1.18	1.31

ELECTRIC OPERATIONS
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	945	862	875	850	848	855	841	832	816	817
Other	16	17	17	18	18	18	19	19	19	20
	3 247	3 276	3 407	3 504	3 630	3 777	3 910	3 996	4 079	4 182
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 258	1 253	1 240	1 240	1 224	1 201	1 166	1 097	1 062	1 024
Depreciation and Amortization	766	779	790	803	810	819	830	841	855	871
Water Rentals and Assessments	133	133	133	134	134	135	135	136	136	137
Fuel and Power Purchased	268	266	273	274	281	291	296	305	309	320
Capital and Other Taxes	162	163	164	165	167	168	169	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
	3 242	3 260	3 281	3 308	3 322	3 328	3 323	3 291	3 291	3 298
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(0)	14	122	190	302	439	575	690	771	866
* 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	11%	11%	12%	12%	14%	16%	18%	21%	24%	28%
Interest Coverage	1.00	1.01	1.10	1.15	1.24	1.36	1.48	1.62	1.71	1.82
Capital Coverage	1.35	1.37	1.54	1.64	1.74	1.99	2.09	2.26	2.35	2.47

ELECTRIC OPERATIONS
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	17 913	19 128	19 988	24 957	28 305	33 137	33 780	34 412	35 076
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 402)	(9 053)	(9 718)	(10 398)
Net Plant in Service	11 487	11 901	12 735	13 193	17 687	20 507	24 735	24 727	24 694	24 679
Construction in Progress	3 257	4 926	6 734	8 945	5 985	3 895	161	185	241	263
Current and Other Assets	1 798	1 569	1 821	2 266	2 284	2 591	2 714	2 147	2 206	2 408
Goodwill and Intangible Assets	198	186	175	165	163	171	162	146	131	115
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 860	21 779	24 922	26 515	27 584	28 205	27 637	27 687	27 864
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 706	22 592	22 755	23 050	23 241
Current and Other Liabilities	2 016	2 160	2 082	3 027	2 125	2 727	2 642	2 097	1 960	1 981
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	2 763	2 830	2 904	2 831	2 739	2 586	2 430	2 292	2 220
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 860	21 779	24 922	26 515	27 584	28 205	27 637	27 687	27 864

ATTACHMENT B - Updated Interest Rates and Net Extraprovincial Revenues

ELECTRIC OPERATIONS
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	35 756	36 478	37 344	38 058	38 793	39 489	40 229	40 984	41 757	42 886
Accumulated Depreciation	(11 092)	(11 801)	(12 526)	(13 267)	(14 022)	(14 792)	(15 575)	(16 374)	(17 188)	(18 018)
Net Plant in Service	24 664	24 677	24 818	24 791	24 771	24 698	24 654	24 611	24 569	24 867
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 363	2 501	2 809	3 234	3 498	3 887	3 780	4 482	5 203	5 982
Goodwill and Intangible Assets	101	87	73	62	51	39	28	17	5	(6)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 823	27 961	28 258	28 654	28 897	29 242	29 120	29 808	30 547	31 409
LIABILITIES AND EQUITY										
Long-Term Debt	23 195	23 798	24 001	24 143	24 076	23 349	23 339	23 343	23 337	22 981
Current and Other Liabilities	1 949	1 432	1 368	1 393	1 365	1 961	1 236	1 192	1 127	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	2 219	2 233	2 355	2 545	2 846	3 284	3 858	4 547	5 318	6 183
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 823	27 961	28 258	28 654	28 897	29 242	29 120	29 808	30 547	31 409

ELECTRIC OPERATIONS
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	1 925	2 016	2 111	2 207	2 322	2 683	2 893	3 002	3 129
Cash Paid to Suppliers and Employees	(803)	(866)	(938)	(968)	(995)	(1 010)	(1 062)	(1 091)	(1 116)	(1 147)
Interest Paid	(511)	(507)	(523)	(562)	(749)	(873)	(1 152)	(1 258)	(1 239)	(1 248)
Interest Received	13	15	20	29	33	34	30	28	14	15
	558	567	575	610	497	473	499	571	662	749
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 800	1 390	1 590	600	570	580
Sinking Fund Withdrawals	110	21	-	8	448	204	293	715	165	25
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	2 023	1 260	932	572	253	284
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contrib	(1 900)	(2 513)	(3 121)	(3 229)	(2 235)	(1 528)	(1 003)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(244)	(261)	(357)	(250)	(256)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 736)	(3 310)	(3 493)	(2 497)	(1 808)	(1 294)	(1 144)	(978)	(983)
Net Increase (Decrease) in Cash	(270)	(93)	101	(25)	22	(76)	138	(1)	(64)	50
Cash at Beginning of Year	133	(137)	(230)	(128)	(153)	(132)	(207)	(70)	(70)	(134)
Cash at End of Year	(137)	(230)	(128)	(153)	(132)	(207)	(70)	(70)	(134)	(84)

ELECTRIC OPERATIONS
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	3 244	3 273	3 404	3 501	3 627	3 773	3 906	3 993	4 075	4 179
Cash Paid to Suppliers and Employees	(1 170)	(1 181)	(1 202)	(1 216)	(1 238)	(1 259)	(1 278)	(1 303)	(1 322)	(1 350)
Interest Paid	(1 256)	(1 255)	(1 254)	(1 267)	(1 269)	(1 254)	(1 234)	(1 143)	(1 123)	(1 098)
Interest Received	18	20	32	44	56	65	75	56	69	83
	836	857	980	1 062	1 177	1 325	1 470	1 603	1 700	1 814
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	380	590	190	190	(10)	(30)	(30)	(10)	(40)	(30)
Sinking Fund Withdrawals	295	101	-	-	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)
	242	211	161	163	(35)	(22)	(51)	(48)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contrib	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(268)	(267)	(275)	(287)	(299)	(308)	(315)	(293)	(304)	(315)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 042)	(1 048)	(1 053)	(1 058)	(1 088)	(1 082)	(1 128)	(1 120)	(1 177)	(1 269)
Net Increase (Decrease) in Cash	36	20	89	167	54	222	290	436	477	499
Cash at Beginning of Year	(84)	(48)	(28)	60	227	282	503	793	1 229	1 705
Cash at End of Year	(48)	(28)	60	227	282	503	793	1 229	1 705	2 204

Section:	Tab 3: Appendix 3.7	**Page No.:**	1
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Interest Rate Forecast		
Issue:	Weighted Average Interest Rate		

PREAMBLE TO IR (IF ANY):

The majority of Manitoba Hydro's capital spending over the next five years will be debt-financed. Manitoba Hydro has provided interest rate forecasts with September and October 2014 vintages.

QUESTION:

Please calculate the reduction in finance expense if existing debt were to be refinanced at lower existing rates.

RATIONALE FOR QUESTION:

To gain an understanding of the financial exposure of the planned capital spending.

RESPONSE:

Manitoba Hydro's existing long term debt advances cannot be redeemed prior to their maturity date and therefore cannot be refinanced before its maturity. Upon maturity, the debt (if it will not be retired) would be refinanced within the IFF at the forecasted interest rates.

Section:	Tab 3 App. 3.3 IFF14 Tab 11.4	Page No.:	Sect. 10.0, p.13 App. 11.4 (WPLP), p.1, App. 11.6, p.2 of 13
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):

In WPLP (IFF12) Undertaking #8 (Dec 19, 2012), Manitoba Hydro indicated the in-service finance expense for the partnership would be $75M for 2015, which corresponds to a total project cost of $1.25B and not the $1.67B total project cost reference in IFF11-2.

QUESTION:

Please file a copy of, or link to, the most recent amended version of the WPLP Agreement.

RATIONALE FOR QUESTION:

This Information Request explores the financing of the WPLP and any impact on Manitoba Hydro.

RESPONSE:

There is no formal agreement between Manitoba Hydro and the Wuskwatim Power Limited Partnership at this time. As indicated in response to PUB Directive 11 from Order 43/13, the parties are still in the process of reviewing and negotiating final terms, which when concluded, will be incorporated into a written agreement.

Pursuant to Order 33/15, Manitoba Hydro will file the renegotiated agreement once it is finalized.

Section:	Tab 3 App. 3.3 IFF14 Tab 11.4	**Page No.:**	Sect. 10.0, p.13 App. 11.4 (WPLP), p.1, App. 11.6, p.2 of 13
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):

In WPLP (IFF12) Undertaking #8 (Dec 19, 2012), Manitoba Hydro indicated the in-service finance expense for the partnership would be $75M for 2015, which corresponds to a total project cost of $1.25B and not the $1.67B total project cost reference in IFF11-2.

QUESTION:

Confirm that the $0.42B capital cost difference comes from Manitoba Hydro's internally generated funds and is not being charged to WPLP.

RATIONALE FOR QUESTION:

This Information Request explores the financing of the WPLP and any impact on Manitoba Hydro.

RESPONSE:

Not confirmed. The determination of $1.25 billion total project in-service cost based on $75 million finance expense in 2014/15 ($75 million / approximate 6% interest rate) is not an accurate representation of the total Wuskwatim in-service cost in IFF11-2. The projected cost in IFF11-2 was $1.67 billion compared to $1.77 billion in IFF12 for an increase of $0.1 billion reflecting projected costs to completion.

The reverse calculation of the in-service cost from the WPLP projected finance expense is not valid for the following reasons:

- The projected finance expense for 2014/15 reported in the WPLP projected financial statements does not include the interest capitalized on Manitoba Hydro's equity contribution that is captured on Manitoba Hydro electric operations projected financial statements;
- The total Wuskwatim project costs to Manitoba Hydro electric operations includes transmission costs which are reflected as an intangible asset under other assets on the WPLP financial statements; and
- Other WPLP cash flows for operations, financing and investing impact WPLP's borrowing and finance expense and are unrelated to the total project in-service cost of Wuskwatim.

Section:	Tab 3 App. 3.3 IFF14 Tab 11.4	**Page No.:**	Sect. 10.0, p.13 App. 11.4 (WPLP), p.1, App. 11.6, p.2 of 13
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):

In WPLP (IFF12) Undertaking #8 (Dec 19, 2012), Manitoba Hydro indicated the in-service finance expense for the partnership would be $75M for 2015, which corresponds to a total project cost of $1.25B and not the $1.67B total project cost reference in IFF11-2.

QUESTION:

Explain how the $0.42B capital cost difference is factored into the amended agreement.

RATIONALE FOR QUESTION:

This Information Request explores the financing of the WPLP and any impact on Manitoba Hydro.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH-I-11b.

Section:	Tab 3 App. 3.3 IFF14 Tab 11.4	Page No.:	Sect. 10.0, p.13 App. 11.4 (WPLP), p.1, App. 11.6, p.2 of 13
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):

In WPLP (IFF12) Undertaking #8 (Dec 19, 2012), Manitoba Hydro indicated the in-service finance expense for the partnership would be $75M for 2015, which corresponds to a total project cost of $1.25B and not the $1.67B total project cost reference in IFF11-2.

QUESTION:

Provide the detailed revenue calculations used for WPLP (IFF14) and compare that with the revenue calculations in IFF12.

RATIONALE FOR QUESTION:

This Information Request explores the financing of the WPLP and any impact on Manitoba Hydro.

RESPONSE:

Under the 2006 Power Purchase Agreement (PPA) between WPLP and MH, WPLP revenue related to energy generated during the on-peak hours is determined based on the average price Manitoba Hydro realizes for long-term export sales and import transactions. WPLP revenue related to energy generated during the off-peak hours is determined from the average price Manitoba Hydro realizes for all on-peak and off-peak opportunity export and import transactions, excluding the on-peak long-term transactions. The total of gross revenue related to on-peak and off-peak energy is reduced by transmission and related market participation charges and Manitoba Hydro's 3% marketing risk fee.

MH14 WPLP revenues incorporated the terms under negotiation in the Wuskwatim PDA Supplement Agreement #2 as at the time MH14 was prepared. MH14 assumes WPLP revenues will include a domestic component which aligns the price of Wuskwatim energy to system unit revenues rather than exports only for a ten year period from 2015/16 to 2024/25. Thereafter, the price of Wuskwatim energy reverts to the 2006 PPA terms noted above.

In addition, the 3% marketing risk fee is eliminated until such time as TPC equity and dividend loans are repaid and then the marketing risk fee increases to 36% for the remainder of the term of the agreement.

The terms assumed in MH14 did not substantively change in the executed PDA Supplement No. 2, except for the addition of an excess spill revenue adjustment.

The following table shows the derivation of WPLP revenues assumed in MH14 with 2015 adjusted for the executed agreement.

Fiscal Year Ending	WPLP PPA Average Unit Revenue (2006 PPA)	WPLP Average Generation Volume	Export Factor	Export Revenue Component	Manitoba Domestic Average Unit Revenue	Domestic Factor	Domestic Revenue Component	WPLP Total Revenue	Marketing Risk Fee	Spill Energy Revenue Adjustment	WPLP Revenue (Net of Marketing Risk Fee)
	$/GW.h	GW.h		(Millions $)	$/GW.h		(Millions $)	(Millions $)	(Millions $)	(Millions $)	(Millions $)
2015	$31	1 369	31%	$13	$63	69%	$60	$73	$0	$12	$84
2016	$33	1 493	30%	$15	$65	70%	$68	$82	$0		$82
2017	$58	1 517	30%	$26	$67	70%	$71	$98	$0		$98
2018	$61	1 517	30%	$28	$70	70%	$75	$103	$0		$103
2019	$65	1 517	30%	$30	$73	70%	$77	$107	$0		$107
2020	$67	1 517	30%	$31	$76	70%	$80	$111	$0		$111
2021	$67	1 517	30%	$30	$78	70%	$83	$114	$0		$114
2022	$72	1 517	30%	$33	$81	70%	$87	$119	$0		$119
2023	$74	1 517	30%	$34	$85	70%	$90	$124	$0		$124
2024	$79	1 517	30%	$36	$88	70%	$93	$129	$0		$129
2025	$82	1 517	30%	$37	$91	70%	$97	$134	$0		$134
2026	$80	1 517	100%	$121	$95	0%	$0	$121	$0		$121
2027	$82	1 517	100%	$124	$99	0%	$0	$124	$0		$124
2028	$84	1 517	100%	$128	$102	0%	$0	$128	$0		$128
2029	$86	1 517	100%	$130	$106	0%	$0	$130	$0		$130
2030	$89	1 517	100%	$135	$110	0%	$0	$135	$0		$135
2031	$93	1 517	100%	$140	$115	0%	$0	$140	$0		$140
2032	$96	1 517	100%	$145	$119	0%	$0	$145	$0		$145
2033	$99	1 517	100%	$151	$121	0%	$0	$151	$0		$151
2034	$103	1 517	100%	$156	$124	0%	$0	$156	$0		$156

The following table provides a comparison of WPLP revenues in MH12, MH14 with the adjustment for the executed Supplement #2, and MH14 under the 2006 PDA assumption.

WPLP Projected Revenue*
(In Millions of Dollars)

Fiscal Year Ending	IFF12	IFF14 Current PPA Formula	IFF14 Supp #2 PPA Formula
2015	$52	$41	$84
2016	$72	$48	$82
2017	$81	$85	$98
2018	$87	$90	$103
2019	$99	$96	$107
2020	$108	$99	$111
2021	$103	$98	$114
2022	$112	$107	$119
2023	$116	$110	$124
2024	$124	$117	$129
2025	$130	$121	$134
2026	$120	$118	$121
2027	$122	$120	$124
2028	$128	$124	$128
2029	$133	$127	$130
2030	$139	$131	$135
2031	$144	$136	$140
2032	$150	$141	$145
2033		$146	$151
2034		$152	$156

*Net of marketing risk fee, where applicable.

Section:	Tab 3 App. 3.3 IFF14 Tab 11.4	**Page No.:**	Sect. 10.0, p.13 App. 11.4 (WPLP), p.1, App. 11.6, p.2 of 13
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):

In WPLP (IFF12) Undertaking #8 (Dec 19, 2012), Manitoba Hydro indicated the in-service finance expense for the partnership would be $75M for 2015, which corresponds to a total project cost of $1.25B and not the $1.67B total project cost reference in IFF11-2.

QUESTION:

Provide the revenue requirement impacts resulting from the renegotiation of the WPLP Agreement.

RATIONALE FOR QUESTION:

This Information Request explores the financing of the WPLP and any impact on Manitoba Hydro.

RESPONSE:

For the purposes of MH14, Manitoba Hydro has incorporated projected impacts to net income which reflect the status of negotiations at the time the forecast was prepared. This results in a projected impact of approximately $15 million to Electric operations net income. It should be noted that there is no formal agreement between Manitoba Hydro and the Wuskwatim Power Limited Partnership (“WPLP”) at this time. As indicated in response to PUB Directive 11 from Order 43/13, the parties are still in the process of reviewing and negotiating final terms, which when concluded, will be incorporated into a written agreement.

Further details will be provided at the time the final written agreement is available.

Section:	Tab 3, App. 3.4	**Page No.:**	pp. 1&2 of 6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	MH's Revenue Requirement		
Issue:	Major G&T Revenue Requirement		

PREAMBLE TO IR (IF ANY):

IFF MH 14 assumes that major G&T project in-service costs can be accommodated by adjusting other non-major G&T project schedules (advancing some and deferring others).

QUESTION:

Please provide a detailed revenue requirement analysis out to 2023/24 (finance expense, OM&A, Depreciation & Amortization, Water Rental and Taxes). This analysis should use total project costs and ignore the notional allocation of internally generated funds. This analysis should be provided for the following projects:

- Wuskwatim (Using $1.7 billion Capital Cost)
- Point Du Bois Spillway (Using $560 million Capital Cost)
- Riel Station ($230 million Capital Cost)
- Bipole III ($4.65 billion Capital Cost)
- Manitoba /Minnesota Transmission ($350 million Capital Cost)
- Great Northern Transmission ($500 million Capital Cost)
- Keeyask G.S. ($6.5 billion Capital Cost)
- Conawapa G.S ($397 million Capital Cost)

RATIONALE FOR QUESTION:

The MFR yet to be filed required MH to quantify major G&T project impacts on IFF 14. This question seeks additional clarification on revenue requirement impacts of specific projects.

RESPONSE:

The information requested is available in Appendix 11.15 Financial Information MFR 9.

Section:	Tab 3, App. 3.4	**Page No.:**	pp. 1&2 of 6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	MH's Revenue Requirement		
Issue:	Major G&T Revenue Requirement		

PREAMBLE TO IR (IF ANY):

IFF MH 14 assumes that major G&T project in-service costs can be accommodated by adjusting other non-major G&T project schedules (advancing some and deferring others).

QUESTION:

A similar analysis for (a) for sustaining capital spending

RATIONALE FOR QUESTION:

The MFR yet to be filed required MH to quantify major G&T project impacts on IFF 14. This question seeks additional clarification on revenue requirement impacts of specific projects.

RESPONSE:

This information is included in Appendix 11.15 Financial Information MFR 9.

Section:	Tab 3, App. 3.4	**Page No.:**	pp. 1&2 of 6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	MH's Revenue Requirement		
Issue:	Major G&T Revenue Requirement		

PREAMBLE TO IR (IF ANY):

IFF MH 14 assumes that major G&T project in-service costs can be accommodated by adjusting other non-major G&T project schedules (advancing some and deferring others).

QUESTION:

Provide a graphical illustration of Major G&T projects cots in (a) separately plotting gross expenses and expenses net of export revenues.

RATIONALE FOR QUESTION:

The MFR yet to be filed required MH to quantify major G&T project impacts on IFF 14. This question seeks additional clarification on revenue requirement impacts of specific projects.

RESPONSE:

Please see Appendix 11.15 Financial Information MFR 9, page 6 of 6, for a table that compares total incremental revenue requirements with and without extra-provincial revenues.

Section:	Tab 3, App. 3.4	**Page No.:**	pp. 1&2 of 6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	MH's Revenue Requirement		
Issue:	Major G&T Revenue Requirement		

PREAMBLE TO IR (IF ANY):

IFF MH 14 assumes that major G&T project in-service costs can be accommodated by adjusting other non-major G&T project schedules (advancing some and deferring others).

QUESTION:

Provide a graphical illustration similar to (c) for sustaining capital.

RATIONALE FOR QUESTION:

The MFR yet to be filed required MH to quantify major G&T project impacts on IFF 14. This question seeks additional clarification on revenue requirement impacts of specific projects.

RESPONSE:

Please see the response to PUB/MH-I-12c.

Section:	Tab 3, App. 3.3	**Page No.:**	
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Revenues		
Issue:	US Exchange Rate Impact on Export Revenue		

PREAMBLE TO IR (IF ANY):

U.S. exports are paid for in U.S. dollars, while Manitoba Hydro's revenue requirement is in Canadian dollars. NFAT PUB/MH I-012(a) (revised Nov 2013) indicated the historical fluctuations on exchange rate revenue.

QUESTION:

Re-file an updated NFAT PUB/MH I-012(a) Revised that includes 2013/14 & 2014/15 actuals and the forecasts for 2016/17 to 2019/20.

Needs For and Alternatives To
PUB/MH I-012a REVISED

	1999/00 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual
Canadian	90,233	109,275	92,615	84,143	53,601	78,255	172,938
U.S.	286,337	370,397	495,278	379,287	297,394	475,243	654,083
Total Extraprovincial Revenues	376,570	479,673	587,893	463,430	350,994	553,499	827,021
Average Exchange Rate	1.17	1.1723	1.5665	1.5445	1.3491	1.2732	1.1893
Average Price/MWh	34.26	39.09	49.02	48.93	49.91	50.51	50.98
U.S. Revenue in US$	244,732	315,958	316,169	245,573	220,439	373,267	549,973

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
Canadian	85,440	110,062	131,363	65,737	63,150	48,289	40,707
U.S.	506,985	514,909	491,283	360,904	335,157	314,755	311,926
Total Extraprovincial Revenues	592,426	624,971	622,646	426,641	398,307	363,044	352,633
Average Exchange Rate	1.1352	1.0256	1.1345	1.0846	1.0191	0.9895	1.0037
Average Price/MWh	51.38	47.36	48.85	32.99	33.31	31.10	34.50
U.S. Revenue in US$	446,604	502,056	433,039	332,753	328,875	318,095	310,776

RATIONALE FOR QUESTION:

In light of recent changes to the exchange rate, an update is required.

RESPONSE:

Please see the attached table which has been updated to include actual results for 2013/14 and forecasted results for 2014/15 through to 2019/20.

Manitoba Hydro’s Foreign Currency Exchange Risk Policy establishes that the Corporation will manage its exposure to foreign currency exchange risk through the use of natural and accounting hedges, along with applicable financial instruments at appropriate times. The expected impacts on Manitoba Hydro’s net income or loss due to changes in the U.S. exchange are minimal.

	1999/00 Actual	2000/01 Actual	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual
Canadian	90 233	109 275	92 615	84 143	53 601	78 255	172 938
U.S.	286 337	370 397	495 278	379 287	297 394	475 243	654 083
Total Extraprovincial Revenues	376 570	479 673	587 893	463 430	350 994	553 499	827 021
Average Exchange Rate	1.17	1.1723	1.5665	1.5445	1.3491	1.2732	1.1893
Average Price/MWh	34.26	39.09	49.02	48.93	49.91	50.51	50.98
U.S. Revenue in US$	244 732	315 958	316 169	245 573	220 439	373 267	549 973

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
Canadian	85 440	110 062	131 363	65 737	63 150	48 289	40 707
U.S.	506 985	514 909	491 283	360 904	335 157	314 755	311 926
Total Extraprovincial Revenues	592,426	624,971	622,646	426,641	398,307	363,044	352,633
Average Exchange Rate	1.1352	1.0256	1.1345	1.0846	1.0191	0.9895	1.0037
Average Price/MWh	51.38	47.36	48.85	32.99	33.31	31.10	34.64
U.S. Revenue in US$	446 604	502 056	433 039	332 753	328 875	318 095	310 776

	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast
Canadian	47 106	38 933	23 997	43 626	43 531	47 304	51 022
U.S.	392 077	369 959	410 160	406 112	413 426	431 373	463 255
Total Extraprovincial Revenues	439 182	408 892	434 157	449 738	456 958	478 677	514 277
Average Exchange Rate	1.0553	1.10	1.12	1.12	1.12	1.12	1.10
Average Price/MWh	36.71	34.67	42.39	55.31	58.28	61.50	65.11
U.S. Revenue in US$	371 531	336 326	366 215	362 600	369 131	385 155	421 141

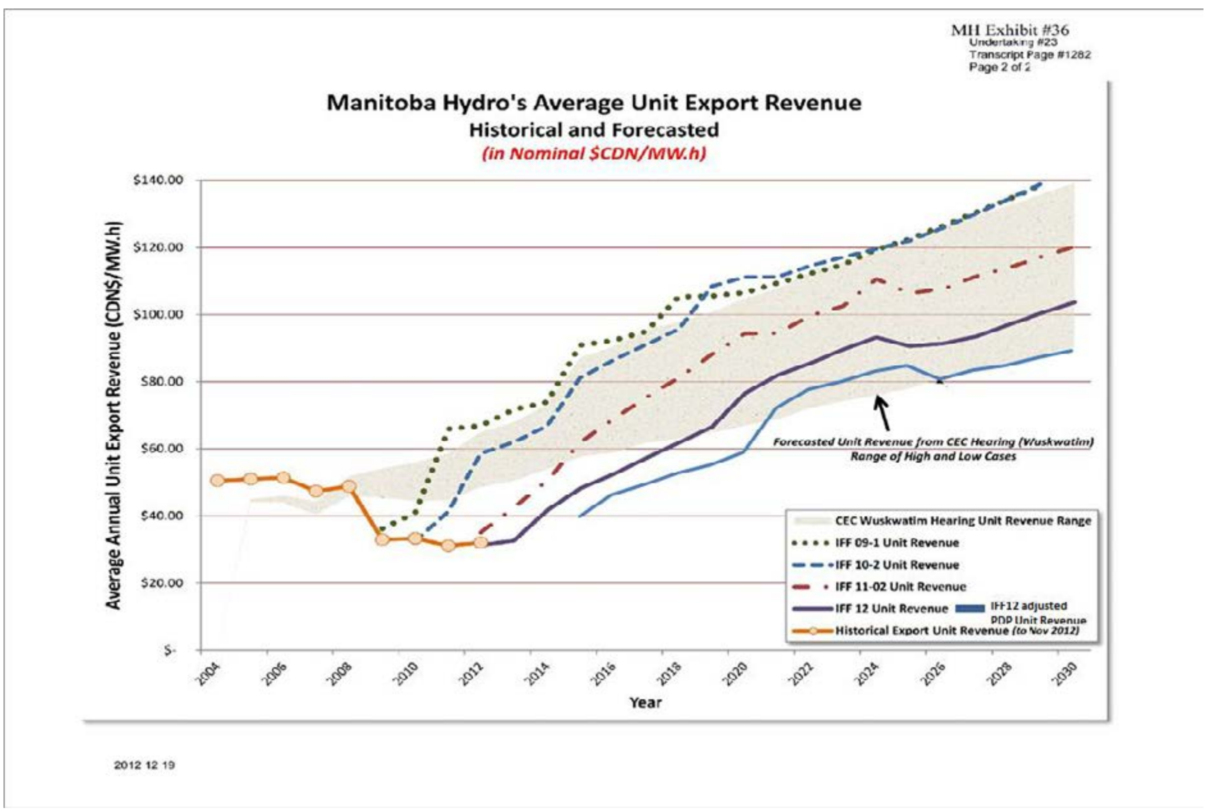
Section:	Tab 3, App. 3.3 MFR (not filed)	Page No.:	Sect. 5.0, pp. 6 & 7
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Revenues		
Issue:	Average Unit Export Revenue Calculations		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has previously filed a historical graph of unit export prices.

QUESTION:

Update the attached graph (MH Exh. #36 NFAT) to include the IFF MH-13 and IFF MH 14 average unit export prices.



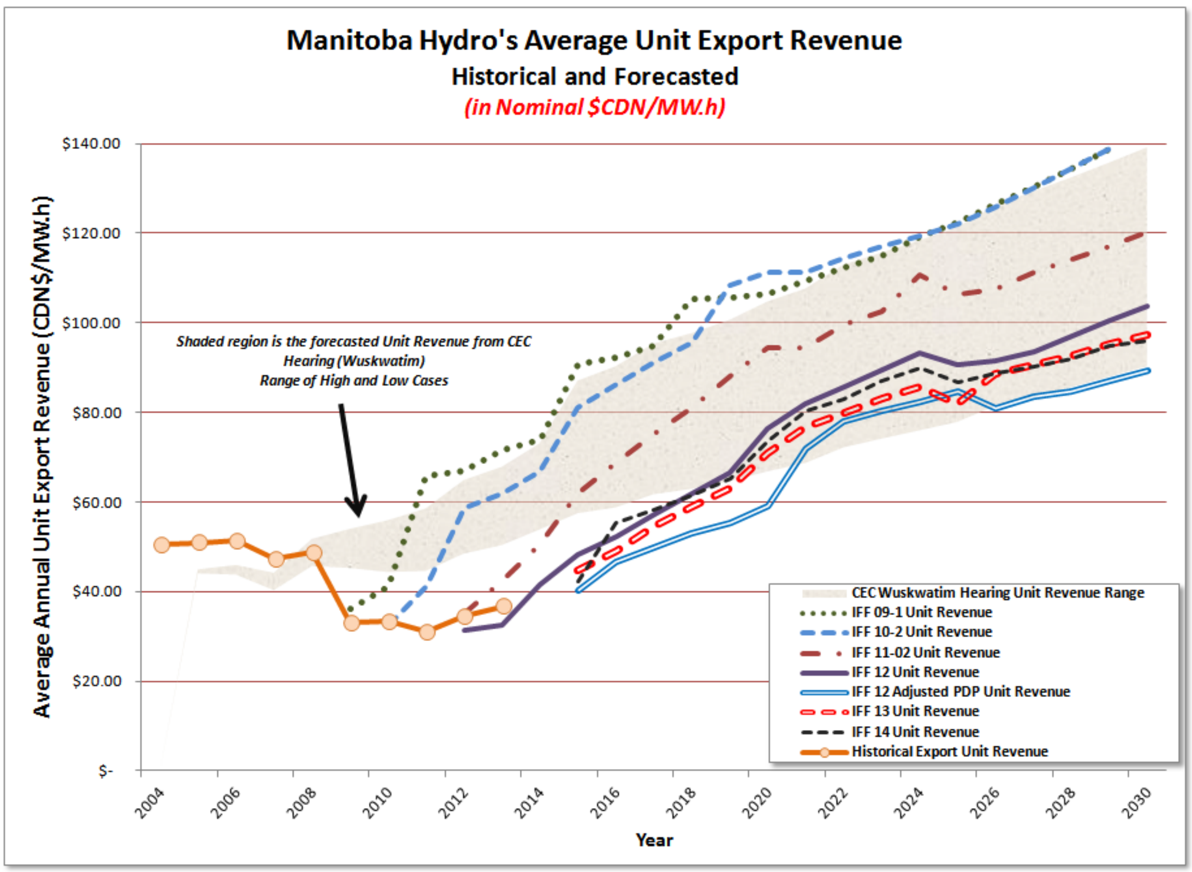
RATIONALE FOR QUESTION:

This Information Request explores changes to unit export prices which affect export revenue assumptions and domestic revenue requirement.

RESPONSE:

An updated graphic with the additional data points requested including IFF13, IFF14 and historic export unit revenue for the 2013/14 fiscal year has been provided below.

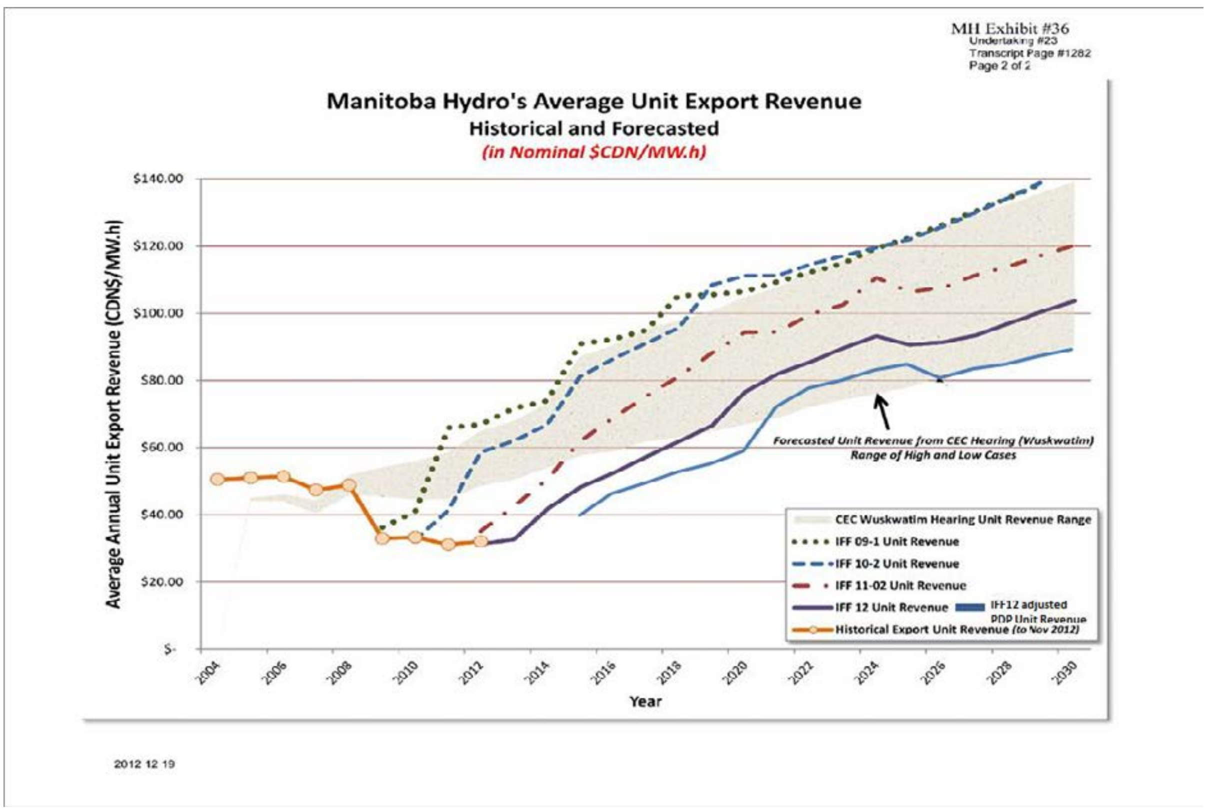
All values are in nominal Canadian dollars per megawatt hour.



Section:	Tab 3, App. 3.3 MFR (not filed)	**Page No.:**	Sect. 5.0, pp. 6 & 7
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Revenues		
Issue:	Average Unit Export Revenue Calculations		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has previously filed a historical graph of unit export prices.



QUESTION:

In the detailed MFR calculations for IFF MH14, provide separate line items for Firm Contract Sales, Peak Opportunity Sales and Off-Peak Opportunity Sales (MFR).

RATIONALE FOR QUESTION:

This Information Request explores changes to unit export prices which affect export revenue assumptions and domestic revenue requirement.

RESPONSE:

This information request discloses export price forecast and contract information that is commercially sensitive and confidential. The request is being answered in confidence under Rule 13 of the Public Utilities Board's Rules of Practice and Procedure, in accordance with PUB Order No. 33/15.

Section:	Tab 3, App. 3.3 App. 11-19	**Page No.:**	Sect 5.0, p. 7 p.3 of 4
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenues		
Issue:	Net Export Revenues		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's net export revenues (after deducting water rentals and fuel & power purchases appear in the following table:

Electric Operations Net Revenues

	Exp	WR	F&PP	Net Export Revenues	Domestic Revenues	Other Revenues	Total Net Revenues
2004/05	554	111	136	307	939	15	1261
2005/06	827	131	125	571	984	17	1572
2006/07	592	112	226	254	1024	16	1294
2007/08	625	124	134	367	1074	23	1464
2008/09	623	123	176	324	1127	34	1485
2009/10	427	121	104	202	1145	27	1374
2010/11	398	120	106	172	1200	41	1413
2011/12	363	119	146	98	1193	45	1336
2012/13	353	118	133	102	1341	69	1512
2013/14	439	125	177	137	1405	70	1612
2014/15	409	124	134	151	1437	15	1603
2015/16	434	123	130	181	1511	14	1706
2016/17	450	112	11	147	1578	14	1729
2017/18	457	112	202	144	1666	14	1824
2018/19	479	112	207	160	1740	15	1905
2019/20	514	112	205	195	1822	15	2032

QUESTION:

Confirm that the attached table reflects the recent history of export revenues and Manitoba Hydro's IFF 14 revenue assumptions out to 2019/20.

RATIONALE FOR QUESTION:

This question explores the projected increase in unit export revenues over the next five years.

RESPONSE:

The table in the preamble contains a mix of Consolidated and Electric Operations Net Revenues. The table has been re-stated to reflect solely the Net Revenues attributable to Electric Operations. Domestic Revenues are net of the Bipole III Reserve account.

Electric Operations Net Revenues

	Exp	WR	F&PP	Net Export Revenues	Domestic Revenues	Other Revenues	Total Net Revenues
2004/05	554	111	135	308	939	4	1251
2005/06	827	131	125	571	984	5	1560
2006/07	592	112	226	254	1024	5	1283
2007/08	625	124	135	366	1075	8	1449
2008/09	623	123	176	323	1127	16	1466
2009/10	427	121	104	202	1145	6	1353
2010/11	398	120	106	172	1200	6	1378
2011/12	363	119	146	98	1193	14	1305
2012/13	353	118	133	101	1341	30	1472
2013/14	439	126	177	137	1405	22	1564
2014/15	409	124	134	150	1407	15	1572
2015/16	434	123	130	181	1479	14	1674
2016/17	450	112	191	147	1544	14	1705
2017/18	457	112	202	143	1630	14	1787
2018/19	479	112	207	160	1729	15	1904
2019/20	514	114	205	195	1822	15	2032

Section:	Tab 3, App. 3.3 App. 11-19	**Page No.:**	Sect 5.0, p. 7 p.3 of 4
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenues		
Issue:	Net Export Revenues		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's net export revenues (after deducting water rentals and fuel & power purchases appear in the following table:

Electric Operations Net Revenues

	Exp	WR	F&PP	Net Export Revenues	Domestic Revenues	Other Revenues	Total Net Revenues
2004/05	554	111	136	307	939	15	1261
2005/06	827	131	125	571	984	17	1572
2006/07	592	112	226	254	1024	16	1294
2007/08	625	124	134	367	1074	23	1464
2008/09	623	123	176	324	1127	34	1485
2009/10	427	121	104	202	1145	27	1374
2010/11	398	120	106	172	1200	41	1413
2011/12	363	119	146	98	1193	45	1336
2012/13	353	118	133	102	1341	69	1512
2013/14	439	125	177	137	1405	70	1612
2014/15	409	124	134	151	1437	15	1603
2015/16	434	123	130	181	1511	14	1706
2016/17	450	112	11	147	1578	14	1729
2017/18	457	112	202	144	1666	14	1824
2018/19	479	112	207	160	1740	15	1905
2019/20	514	112	205	195	1822	15	2032

QUESTION:

Confirm that Manitoba Hydro's anticipated export volumes in 2014/15 and 2015/16 are about 10,500 GWh/yr, compared to about 8,000 GWh/yr from 2016/17 to 2019/20.

RATIONALE FOR QUESTION:

This question explores the projected increase in unit export revenues over the next five years.

RESPONSE:

The export volumes projected in IFF14 are provided in the Application in Appendix 11.19 Average Unit Revenue /Cost Calculation IFF14 which is reproduced below.

VOLUMES (in GWh)	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Firm & Opportunity Export Sales to Canada	851	481	860	833	856	870
Firm & Opportunity Export Sales to US	9,184	8,596	6,444	6,192	6,143	6,289
Total Firm & Opportunity Sales	10,035	9,077	7,304	7,025	6,999	7,159

The export volumes listed in question PUB/MH-I-15 b) appear to have been copied from Figure 9.3 (Tab 9) of the Application and include transmission losses. The export volumes reproduced from Appendix 11.19 represent delivered energy to the customer, less the transmission losses.

As was noted on page 6 of Appendix 3.3 (IFF14):

> *"Extra-provincial sales volumes are forecast for the first forecast year (2014/15) based upon the expected inflow conditions as of October 2014 and actual reservoir and lake level elevations as of September 2014. The second forecast year (2015/16) uses the median of 80 years of historic inflows and initial reservoir and lake level elevations carried forward from the 2014/15 forecast. For 2016/17 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 102 years (1912/13 to 2013/14)."*

The total export volumes in the first two years of the IFF are significantly above long term export volumes as the current favourable water flow conditions being experienced are incorporated into the first two years of IFF14. New resources such as Keeyask G.S. or the losses reduction associated with Bipole 3 result in an increase in export volumes.

Section:	Tab 3, App. 3.3 App. 11-19	Page No.:	Sect 5.0, p. 7 p.3 of 4
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenues		
Issue:	Net Export Revenues		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's net export revenues (after deducting water rentals and fuel & power purchases appear in the following table:

Electric Operations Net Revenues

	Exp	WR	F&PP	Net Export Revenues	Domestic Revenues	Other Revenues	Total Net Revenues
2004/05	554	111	136	307	939	15	1261
2005/06	827	131	125	571	984	17	1572
2006/07	592	112	226	254	1024	16	1294
2007/08	625	124	134	367	1074	23	1464
2008/09	623	123	176	324	1127	34	1485
2009/10	427	121	104	202	1145	27	1374
2010/11	398	120	106	172	1200	41	1413
2011/12	363	119	146	98	1193	45	1336
2012/13	353	118	133	102	1341	69	1512
2013/14	439	125	177	137	1405	70	1612
2014/15	409	124	134	151	1437	15	1603
2015/16	434	123	130	181	1511	14	1706
2016/17	450	112	11	147	1578	14	1729
2017/18	457	112	202	144	1666	14	1824
2018/19	479	112	207	160	1740	15	1905
2019/20	514	112	205	195	1822	15	2032

QUESTION:

Explain why Manitoba Hydro is forecasting an average unit revenue increase from 3.5 ¢/kWh in 2014/15 to 6.5 ¢/kWh in 2019/20 (which is an average 17%/yr increase).

RATIONALE FOR QUESTION:

This question explores the projected increase in unit export revenues over the next five years.

RESPONSE:

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.

For the year 2014/15, current water conditions are well above average which results in high volumes of export energy. Similarly, the export volumes for 2015/16 are above average in part because of the hydraulic carryover of energy in the reservoirs because of the high flows in the preceding year. With high export volumes, average unit revenues for exports are lower because of the increased volume of off-peak energy sales.

In years 2016/17 and beyond, the average unit revenue and associated volumes are based on the average from 102 historic flow years. By averaging over the entire flow range, there is proportionally less off-peak energy sales which results in higher overall average unit prices. The average unit revenue for year 2016/17 is equal to 5.5¢/kWh. The average annual rate of change of the unit revenue is approximately 6%/year for the period from 2016/17 to 2019/20.

The average unit revenue figures are in nominal dollars and increase with inflation which is currently in the order of 2% per year.

Section:	Tab 3, App. 3.3	Page No.:	Sect. 5, p.6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenue		
Issue:	Energy & Capacity Sales into the Export Market		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's Tab 3, App. 3.3 Section 5.0 listing of long term export contracts should equate to the Tab 9 (p. 7 of 23) listing of contracted exports:

2014/15	-	4537 GWh
2015/16	-	4051 GWh
2016/17	-	3406 GWh
2017/18	-	4339 GWh
2018/19	-	3282 GWh
2019/20	-	3192 GWh

QUESTION:

Please provide annual firm energy and capacity sales anticipated under each contract during the 2014/15 to 2019/20 period.

RATIONALE FOR QUESTION:

This Information Request seeks to reconcile listed export contracts with projected export revenues.

RESPONSE:

The information requested is commercially sensitive and has been filed in confidence with the PUB.

Section:	Tab 3, App. 3.3	**Page No.:**	Sect. 5, p.6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenue		
Issue:	Energy & Capacity Sales into the Export Market		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's Tab 3, App. 3.3 Section 5.0 listing of long term export contracts should equate to the Tab 9 (p. 7 of 23) listing of contracted exports:

2014/15	-	4537 GWh
2015/16	-	4051 GWh
2016/17	-	3406 GWh
2017/18	-	4339 GWh
2018/19	-	3282 GWh
2019/20	-	3192 GWh

QUESTION:

Explain the listed April 2014 end of the 500 MW NSP contract in light of continued NEB listed sales under NEB Permit 224 up to Dec 2014.

RATIONALE FOR QUESTION:

This Information Request seeks to reconcile listed export contracts with projected export revenues.

RESPONSE:

In Appendix 3.3, the 500 MW NSP contract should reflect an expiry of April 2015. The NEB Permit 224 is also valid up to April 30, 2015 and includes all energy delivered under the contract.

Section:	Tab 3, App. 3.3	**Page No.:**	Sect. 5, p.6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenue		
Issue:	Energy & Capacity Sales into the Export Market		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's Tab 3, App. 3.3 Section 5.0 listing of long term export contracts should equate to the Tab 9 (p. 7 of 23) listing of contracted exports:

2014/15	-	4537 GWh
2015/16	-	4051 GWh
2016/17	-	3406 GWh
2017/18	-	4339 GWh
2018/19	-	3282 GWh
2019/20	-	3192 GWh

QUESTION:

Quantify the diversity agreement sales included in Tab 9 (p.7 of 23) and confirm there is no capacity revenue.

RATIONALE FOR QUESTION:

This Information Request seeks to reconcile listed export contracts with projected export revenues.

RESPONSE:

The diversity agreement sales are included in the list of contracts at the beginning of Appendix 3.3, Section 5.0 Extra-Provincial Revenue. Manitoba Hydro confirms there is no capacity revenue received for capacity provided during the summer season nor a capacity cost for capacity made available to Manitoba Hydro in the winter season under the diversity agreements.

Please also refer to PUB/MH-I-61b for quantification of diversity energy sales.

Section:	Tab 3, App. 3.3	Page No.:	Sect. 5, p.6
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Extra Provincial Revenue		
Issue:	Energy & Capacity Sales into the Export Market		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's Tab 3, App. 3.3 Section 5.0 listing of long term export contracts should equate to the Tab 9 (p. 7 of 23) listing of contracted exports:

2014/15	-	4537 GWh
2015/16	-	4051 GWh
2016/17	-	3406 GWh
2017/18	-	4339 GWh
2018/19	-	3282 GWh
2019/20	-	3192 GWh

QUESTION:

Re-file NFAT PUB/MH I – 017 (revised Dec/13) updated to Jan 2015 adding the monthly revenues to the sales volumes.

RATIONALE FOR QUESTION:

This Information Request seeks to reconcile listed export contracts with projected export revenues.

RESPONSE:

NFAT PUB/MH I-017 (revised Dec/13) has been updated to Jan 2015 adding the monthly revenues to the sales volumes.

	Diversity Sales		Diversity Purchases
	MWh	$CDN	MWh
Apr-02	0	0	156,369
May-02	6,470	189,235	28,570
Jun-02	48,400	2,135,635	22,358
Jul-02	49,150	1,737,612	33,436
Aug-02	38,250	983,391	25,800
Sep-02	55,285	2,012,323	25,841
Oct-02	21,750	729,261	32,276
Nov-02	0	0	62,795
Dec-02	0	0	52,749
Jan-03	0	0	54,154
Feb-03	0	0	62,729
Mar-03	0	0	76,677
Apr-03	0	0	44,380
May-03	0	0	0
Jun-03	66,445	2,885,752	300
Jul-03	166,627	8,107,053	0
Aug-03	139,891	6,656,928	0
Sep-03	26,930	1,162,354	0
Oct-03	0	0	0
Nov-03	0	0	0
Dec-03	0	0	8,250
Jan-04	0	0	9,445
Feb-04	0	0	10,025
Mar-04	0	0	0
Apr-04	0	0	0
May-04	0	0	0
Jun-04	55,840	2,640,363	0
Jul-04	165,384	8,808,073	0
Aug-04	176,792	8,985,257	0
Sep-04	42,452	1,804,960	0
Oct-04	0	0	0
Nov-04	0	0	7,000
Dec-04	0	0	8,475
Jan-05	0	0	9,600

	Diversity Sales		Diversity Purchases
	MWh	$CDN	MWh
Feb-05	0	0	9,275
Mar-05	0	0	6,000
Apr-05	0	0	0
May-05	0	0	0
Jun-05	65,448	3,252,999	0
Jul-05	157,186	7,936,880	0
Aug-05	143,900	5,884,283	0
Sep-05	55,820	1,906,545	0
Oct-05	18,450	428,707	0
Nov-05	0	0	9,550
Dec-05	0	0	21,675
Jan-06	0	0	8,200
Feb-06	0	0	11,825
Mar-06	0	0	5,600
Apr-06	0	0	0
May-06	10,250	581,600	0
Jun-06	43,600	1,550,675	0
Jul-06	106,544	4,847,336	0
Aug-06	130,750	5,255,960	0
Sep-06	28,320	1,054,458	0
Oct-06	0	0	0
Nov-06	0	0	700
Dec-06	0	0	5,625
Jan-07	0	0	4,650
Feb-07	0	0	10,200
Mar-07	0	0	1,125
Apr-07	0	0	750
May-07	63,368	3,856,843	0
Jun-07	111,500	5,347,234	0
Jul-07	208,410	9,198,857	0
Aug-07	225,216	9,470,461	0
Sep-07	103,292	3,768,045	0
Oct-07	91,371	3,153,373	0
Nov-07	0	0	0

	Diversity Sales		Diversity Purchases
	MWh	$CDN	MWh
Dec-07	0	0	0
Jan-08	0	0	0
Feb-08	0	0	0
Mar-08	0	0	0
Apr-08	150	0	0
May-08	81,574	3,401,427	0
Jun-08	108,009	4,599,426	0
Jul-08	220,250	10,071,543	0
Aug-08	226,500	9,286,960	0
Sep-08	140,567	4,835,748	0
Oct-08	111,450	4,153,724	0
Nov-08	0	0	0
Dec-08	0	0	3,892
Jan-09	0	0	6,426
Feb-09	0	0	0
Mar-09	0	0	1,230
Apr-09	0	0	0
May-09	134,821	2,145,938	0
Jun-09	160,149	4,470,598	0
Jul-09	211,201	5,184,966	0
Aug-09	232,839	5,668,885	0
Sep-09	49,369	1,685,485	0
Oct-09	77,706	2,358,613	0
Nov-09	0	0	11,550
Dec-09	0	0	38,549
Jan-10	0	0	49,820
Feb-10	0	0	20,150
Mar-10	0	0	0
Apr-10	0	0	0
May-10	53,700	1,842,176	0
Jun-10	149,196	5,095,974	0
Jul-10	205,825	7,101,662	0
Aug-10	207,604	7,658,888	0
Sep-10	140,725	3,854,088	0

	Diversity Sales		Diversity Purchases
	MWh	$CDN	MWh
Oct-10	108,019	2,626,733	0
Nov-10	0	0	0
Dec-10	0	0	14,250
Jan-11	0	0	12,000
Feb-11	0	0	0
Mar-11	0	0	0
Apr-11	0	0	0
May-11	42,927	761,934	0
Jun-11	180,055	4,723,817	0
Jul-11	199,484	6,860,638	0
Aug-11	200,750	6,509,329	0
Sep-11	152,591	4,302,713	0
Oct-11	108,181	2,342,694	0
Nov-11	91,354	2,321,519	0
Dec-11	73,016	2,086,927	0
Jan-12	70,101	1,685,321	0
Feb-12	68,150	1,666,184	8,079
Mar-12	68,747	1,455,483	19,276
Apr-12	55,841	1,221,903	0
May-12	76,063	2,221,192	0
Jun-12	159,385	4,985,737	0
Jul-12	197,478	6,889,944	0
Aug-12	207,048	6,089,883	0
Sep-12	151,701	3,780,881	0
Oct-12	83,118	2,206,126	0
Nov-12	67,050	1,927,256	0
Dec-12	61,875	2,123,564	1,050
Jan-13	66,150	2,181,518	0
Feb-13	66,150	2,076,848	0
Mar-13	86,700	2,820,083	0
Apr-13	103,820	3,357,126	0
May-13	111,440	3,163,406	0
Jun-13	165,276	5,259,685	0
Jul-13	216,975	7,613,270	0

	Diversity Sales		Diversity Purchases
	MWh	$CDN	MWh
Aug-13	207,118	7,193,147	0
Sep-13	116,409	3,562,896	0
Oct-13	106,105	3,045,102	0
Nov-13	83,290	2,287,598	0
Dec-13	52,414	2,191,692	3,150
Jan-14	20,400	883,602	48,415
Feb-14	4,500	250,082	93,300
Mar-14	44,100	1,594,046	46,050
Apr-14	93,413	2,858,195	4,500
May-14	62,597	2,133,036	0
Jun-14	164,376	5,485,535	0
Jul-14	209,834	7,269,900	0
Aug-14	205,286	7,363,089	0
Sep-14	150,761	4,713,029	0
Oct-14	39,011	937,722	0
Nov-14	0	0	0
Dec-14	0	0	0
Jan-15	0	0	0

Section:	Tab 4: Appendix 11.35 & 11.36	**Page No.:**	
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's total capital expenditures have shown material changes and are a major driver behind requested rate increases.

QUESTION:

Please provide continuity schedules by major project of construction work in progress for the years 2015 through 2020.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital cost escalation.

RESPONSE:

Please see the following schedule.

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
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	**2,151**	**1,357**	**1,036**	**2,466**	**1,823**	**152**	**4,129**	**2,366**	**116**	**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
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**	**5,724**	**807**	**2,822**	**3,701**

Section:	Tab 4: Appendix 11.35 & 11.36	**Page No.:**	
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's total capital expenditures have shown material changes and are a major driver behind requested rate increases.

QUESTION:

Please provide a breakdown of Other for Keeyask, Conawapa, and Bipole III by major component.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital cost escalation.

RESPONSE:

The 'Other' category contains costs consisting of consulting services provided by external vendors, including engineering, management and architecture; general construction and maintenance services provided by external vendors including assembly and installation; unamortized site study costs which were previously deferred and have now been re-allocated to the capital project to construct the asset; and community participation which are payments to First Nation and other communities as negotiated through formal agreements between Manitoba Hydro and these communities.

Please see below for a breakdown of 'Other' for Keeyask, Conawapa and Bipole III as of March 31, 2014.

Breakdown of Other for Major Generation and Transmission projects

Keeyask	
Construction & Maintenance Services	237.0
Consulting Services	217.6
Site Study Costs	53.0
Community Participation	35.3
Mitigation Settlement	13.1
Professional Fees	7.7
Transport of people including charters, MV mileage	7.6
Building & Property Services	3.4
Adverse Effects	2.5
Other	4.9
	582.1

Conawapa - Generation	
Mitigation Settlement	4.9
Consulting Services	2.1
Other	0.2
	7.2

Conawapa - Licensing	
Consulting Services	91.3
Community Participation	11.9
Site Study Costs	10.3
Construction & Maintenance Services	8.7
Transport of people including charters, MV mileage	12.5
Other	8.0
	142.7

Bipole III - Transmission Line	
Consulting Services	25.4
Construction & Maintenance Services	20.1
Community Participation	7.3
Transport of people including charters, MV mileage	7.2
Construction related vehicles	4.4
Licenses & Fees	1.9
Site Study Costs	1.1
Other	3.0
	70.4

Bipole III - Converter Stations	
Construction & Maintenance Services	156.9
Consulting Services	24.5
Transport of people including charters, MV mileage	5.5
Building & Property Services	3.0
Site Study Costs	1.0
Other	4.4
	195.3

Bipole III Collector Lines	
Construction & Maintenance Services	16.5
Land Purchases	2.8
Other	1.3
	20.6

Bipole III Community Development Initiative	
Mitigation	53.9
	53.9

Section:	Tab 4: Appendix 11.35 & 11.36	**Page No.:**	
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's total capital expenditures have shown material changes and are a major driver behind requested rate increases.

QUESTION:

Please provide an update to PUB/MH I-93 (a) from the 2012 GRA to include CEF12, CEF13 and CEF14. Please total the schedule.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital cost escalation.

RESPONSE:

Please see the following table.

Progression of Project Costs in $ M												
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF-10	CEF-11-2	CEF-12	CEF-13	CEF-14
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275	1,375	1,449	1,449	1,449
Wuskwatim Transmission		199	200	257	320	316	316	291	298	323	320	320*
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566	1,673	1,771	1,768	1,768
Herblet Lake Transmission	57	55	54	54	95	93	93	75	75	77	76	76*
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	3,280	3,280	3,280	3,280	4,653
Riel C.S.	96	101	103	103	105	268	268	268	268	268	330	330
Kelsey G.S.	121	121	166	166	184	190	190	302	302	302	302	340
Kettle G.S.		61	61	61	61	76	76	166	166	166	166	192
Pointe du Bois Spillway							318	398	398	560	560	575
Pointe du Bois Trans.					83	86	86	86	86	86	114	114
Pointe du Bois Rebuild	421	288	692	834	818	818		1,538	1,538	1,538	1,538	1,852
Slave Falls G.S.				179	192	198	198	223	230	230	126	126
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771	7,771	10,192	10,492	397
Keeyask G.S.						3,700	4,592	5,637	5,637	6,220	6,220	6,496
500 KV Dorsey U.S. Border						205	205	205	205	205	350	350
Total	2,043	7,154	9,742	10,957	11,954	16,042	17,781	23,081	23,302	26,665	27,091	19,038

*Wuskwatim Transmission and Herblet Lake Transmission Projects are in-service and have no further capital spending. These projects were removed from CEF14 but included in this table for completeness.

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	**Page No.:**	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please provide Manitoba Hydro's definition for the terms major capital, base capital, and sustaining capital.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

Major capital consists of projects with a total budget greater than $50 million and requires Executive Committee approval.

Base capital includes items with a total forecast of less than $50 million and is approved at the Business Unit level.

Sustaining capital includes items identified in CEF14 as either Major or Base capital expenditures and consists of additions, improvements and replacements of existing infrastructure.

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	**Page No.:**	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please provide the quantification to support the $25 million target adjustment for sustaining capital.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

Manitoba Hydro recognizes that additional capital investment is needed to address the increasing pressures associated with aging infrastructure, capacity constraints and other corporate initiatives. The target adjustment of $25 million for 2016/17 to 2020/21 allows for an approximate 5% annual increase over committed business unit targets. The additional funding is to address future priorities while balancing the financial risks associated with higher levels of debt required to fund major new generation and transmission projects.

For 2014/15 and 2015/16 the adjustment has been allocated to Human Resources and Corporate Services to assist in funding the new Customer Service Centres (CSC) necessitated by the Customer Service Operations district consolidation initiative.

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	**Page No.:**	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please provide the value engineering studies or reports, if any, that Manitoba Hydro prepared to support its increase to sustaining capital expenditures since 2008.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

Although there is not a specific set of studies or reports supporting the increase to sustaining capital expenditures since 2008, there are a multitude of reports that are relied upon for the justification of the projects outlined in CEF 14.

Please see the CEF 14 report, filed as Appendix 4.1 of Tab 4 of the Application which outlines a description and the justification for all of Manitoba Hydro's major projects and base capital spending by Business Unit.

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	**Page No.:**	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please provide any studies prepared by or obtained by Manitoba Hydro since 2008 that indicate what sustaining capital expenditures can be deferred.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

Manitoba Hydro's process for prioritizing capital expenditures is discussed in the response to COALITION/MH-I-11a.

Manitoba Hydro actively manages its capital investment requirements by prioritizing its sustaining capital plans to mitigate its operational and business risks and to give highest priority to those projects that contribute the most to achieving those objectives.

As a result of the ongoing review of project priorities, some projects will be advanced and others will be deferred to accommodate those projects of greater relative value. In addition, there may be short term deferral or advancement strategies employed as it is possible that specific project schedules may be revised due to resource or material availability or other scheduling considerations.

Manitoba Hydro assesses its technical options that are available when determining a specific course of action related to an asset or group of assets. The replacement of some types of assets may be deferred by implementing maintenance practices and employing technological innovation to extend the service life of the asset in question.

One example of the type of project undertaken to extend the life of an asset, and thereby deferring the need for its replacement, is the rehabilitation of underground cable by way of silicon injection. With advanced techniques to inject silicon into the cable to minimize electrical faults from moisture penetration, the life of a many cables can be increased by between 20 and 40 years. Please see the attachment to this response for the report on the Cable Rehabilitation Program.

Manitoba Hydro

CUSTOMER SERVICE AND DISTRIBUTION

Customer Service Operations South Division

Distribution Asset Maintenance Department

REPORT ON

Cable Rehabilitation Program 2014

PREPARED BY:	Bryan Kenning
DATE PREPARED:	2015 01 12
REVIEWED BY:	Owen Preston
FILE NUMBER:	
RECOMMENDED FOR IMPLEMENTATION	
DEPARTMENT:	Distribution Asset Management
DIVISION:	Business Support & Capital Asset Management
DATE:	2015 01 21

PROVINCE OF MANITOBA
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EXECUTIVE SUMMARY

Within the Province of Manitoba, there is currently 3,976km of underground XLPE cable servicing the distribution network. Due to the breakdown of insulation caused by water treeing, this cable type is now approaching its expected end of life. Historically the primary method of system restoration was direct replacement with TRXLPE cable, which is extremely costly.

A pilot program to evaluate the logistics of mitigating this through cable injections was implemented and it was found that both medium and low pressure silicon injection are a viable alternative to direct cable replacement with significant cost savings.

The Cable Rehabilitation Program was instituted to rejuvenate 70-100km of underground cable annually over the next 30 years. The fiscal years 2013-2014 and 2014-2015 produced 22km and 25.4km of cable rehabilitated respectively with the goal of expanding the program for 2015-2016 to achieve the 70-100km target.

Manitoba Hydro has now successfully rehabilitated 79.2km of cable which accounts for 5.2% of all 15kv XLPE cable in the distribution system.

It is recommended that a one (1) year contract with two (2) single year options for Silicon Injection be tendered for the fiscal years 2015-2018 inclusive for Suburban Winnipeg. It is also recommended that a one (1) year contract for summer 2015 be tendered for Silicon Injection to evaluate the feasibility of the program for South and North Divisions in urban cities and townships.

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1. INTRODUCTION

There is currently 3,976km of underground XLPE cable within the province of Manitoba which accounts for 44% of the underground distribution network. These cables were installed between 1970 and 1986 with an anticipated life span of 50 years. Due to water treeing within the cable's insulation, this asset's life expectancy has been reduced to 30 years. As a result, these cables have now reached or exceeded their anticipated end of life.

There are 2 voltage classes of XLPE cable utilized by Manitoba Hydro, 15kV and 25kV. Since 1988, 75% of all underground ground cable faults have occurred on 15kv XLPE cable. There is 1529km of this type of cable in Manitoba Hydro's underground plant.

The most common method of mitigation is cable replacement using TRXLPE underground cable. Approximately 12km of XLPE cable is replaced per year by Manitoba Hydro. Given this schedule, full replacement of XLPE conductor with TRXLPE cable will take 328 years with the current Regional Unit Cost Estimating System (RUCUS) rate being $200 per meter.

An alternative to cable replacement is cable injection. Using this method, the existing cable's insulation is rejuvenated by injecting a silicone based fluid through the strands of the conductor which flushes out impurities and encapsulates any water treeing within the cable's insulation. The two injection methods available are medium pressure and low pressure.

2. METHODS

For the medium pressure injection method, the rejuvenation fluid is placed under pressure and forced through the stranding of the conductor. This method must be done on de-energized cable and as a result, the customer may experience an outage during the injection period. In most cases, the injection of one segment of cable can be completed in less than 4 hours. The injection process is not seasonally dependant; however, it has been found to be slower during subzero conditions. Medium pressure injection can only take place on complete segments of cable as fluid flow through splices is not possible. This method offers a 40 year warranty.

In low pressure injection, a vacuum is created at the receiving end of the cable segment, causing the rejuvenation fluid to be pulled through the stranding of the conductor. The set up of the low flow method must be done on de-energized cable; however, once the vacuum tanks have been installed, the injection process can be completed through energized lines. The injection time of one cable segment varies and can range from hours to months, depending on a variety of factors such as cable types, segment lengths and environmental conditions. Low pressure injection can be completed on spliced cables; however, the rate of fluid flow is reduced as the number of splices on the line increases. This method offers a 20-25 year warranty.

3. HISTORY

Manitoba Hydro has completed several pilot projects to evaluate the validity and feasibility of cable injections on existing XLPE underground cables. **Between 2003 and 2013, 53.7kms of cable was successfully rehabilitated with various silicon injection methods. This represents 3.5% of all 15kv XLPE cable in the underground plant.** There has been only one reported failure of an injected cable and this was due to workmanship on a cable termination (end).

CSC	Feeder	Year	Km Injected
Keewatin	CO271	2003	12.0
River East	SD791	2005	5.3
Fort Garry	CR363	2006	9.5
Fort Garry	CR365	2007	4.6
Keewatin	IR763/CO285	2013	22.0

The 2013 Project deviated significantly from prior projects as all cable that was not injected was submitted for cable replacement. Comparably the 2003-2007 projects only replaced cable retroactively on an as needed basis as cables failed. As a result these feeders continue to have cable failures and remain on the list of “Worst Performing Feeders”. The Cable Rehabilitation program will now utilize data from the Insulation Testing Program to determine the overall health of individual cable segments. Cables that are not injected, but remain in very good condition will be deferred and retested in the future. Cables that are not injected and show signs of degradation will be candidates for replacement.

4. PROJECT SCOPE

For 2014 a target of rehabilitating 35km of cable was set utilizing 2 contractor crews and 2 Manitoba Hydro crews from July to November. 9 different Feeders from the Dakota/Frobisher Station area in St Boniface CSC was selected with the contract awarded to Novinium Inc.

5. WORK AREA

Dakota and Frobisher station areas reported over 2 million customer outage minutes from 50 cable faults over the 2006-2013 timeframe. This represents 18% of all cable failures in the Suburban Winnipeg CSC area, the highest total for 2 stations in an adjoining area over the reporting period. There is over 92km of 15kv XLPE 1/0 cable in this combined 2 station area with 50km selected for the 2014 program.

6. HIGHLIGHTS

Over 63 days, work was performed on 40 kilometers of cable with 25.4km being rehabilitated with either medium or low pressure methods for a 63.6% success rate. **Manitoba Hydro has now rejuvenated 79.2km representing 5.2% of all 15kv XLPE cable in the underground distribution system.**

There were 269 segments in the work area and 187 were successfully rehabilitated representing a 69.5% individual segment success rate. The remaining 30.5% will be evaluated with data from insulation testing and recommended for replacement based on degradation.

The following chart explains the amount injected per feeder of 15kv XLPE 1/0 cable for each feeder in the 2014 work area. It provides:

Completion % Total percentage of the entire Feeder that was worked on during the project
Injection % Total percentage of the entire Feeder that is now injected
Work Area Total meters of cable worked on per Feeder
Injected Total meters injected per Feeder

Feeder	Completion %	Injection %	Work Area	Injected
FBR 12-16	100.0%	100.0%	408	408
DK 745	84.8%	56.0%	11788	7785
DK 734	77.8%	54.3%	8008	5596
FBR 12-7	57.1%	40.3%	9062	6404
DK 744	45.3%	39.1%	1541	1330
DK 749	40.0%	22.9%	2416	1382
DK 731	38.2%	16.6%	2674	1159
DK 746	34.6%	18.1%	1964	1024
DK 732	6.9%	6.9%	333	333
TOTAL	**59.3%**	**37.7%**	**39976**	**25421**

Note: Work will continue on these feeders for the 2015 Rehabilitation Program

7. COSTS

The overall per unit cost of the injection program was $38.87/m which is 25.4% below the $52.07 cost per meter from the 2013 injection pilot project and 2.8% below the $40.00/m budget.

Cost	Budget	Actual	Variance
Novinium Inc	$773,731.13	$545,223.11	-$228,508.02
Manitoba Hydro	$373,904.60	$442,980.12	$69,075.52
TOTAL	**$1,147,635.73**	**$988,203.23**	**-$159,432.50**

The breakdown for contractor labour costs are as follows: $94,990.00 for general labour and $19,044.00 for overtime labour. The work was completed by a two man crew who charged 1032.5 hours of general time and 138 hours of overtime towards the project. The fluid cost for injecting cable was $12.79/m for single phase 1/0 cable. The work area was varied and consisted of dead front, live front, junction point, cable pole and switchgear equipment and as a result, the amount of switching required was significant.

Internal labour costs associated with the Novinium injections were primarily Time Domain Reflectometry (TDR) testing, switching and injection elbow installation. All work was completed by a four journeyman crew and 1 apprentice whose charge out time breakdowns as follows: 2896.72 hours totaling $237,531.04 for general labour and 808.5 hours totaling $96,211.5 for overtime labour.

Rehabilitation vs. Replacement Comparison

The estimated cost to direct replace single phase conductor as per the 2014 Customer Service Quotation Schedule is $53.34 per meter, and to replace three phase conductor is $82.08 per meter. By comparison the $38.87 cost per meter for rejuvenation of these cables provided a significant cost savings of 27-53% respectively. **Utilizing the RUCES estimate of $200 per meter for cable replacement the cost savings are substantial at 80.6%.**

Method	Cost per Meter	Total Cost
Rehabilitation	$38.87	$988,114.27
Replacement	$200.00	$5,084,200.00
Total Cost Reduction	**80.6%**	**$4,096,085.73**

8. OBSERVATIONS

At the completion of the 2014 project, a number of processes were identified as having a positive impact on the overall project:

- Pre-Assessing Injection Region: Prior to the onset of the injections, 2 crews were sent to review the feeder that was to be injected. The following tasks were performed:
    1. Confirmation of transformer types.
    2. Identification of Padmounted equipment base type for cable slack verification.
    3. Identification of new cable (i.e. uninjectable).
    4. Clean up of non-switchable locations.
    5. Inspect splices for material requirements.
    6. Provide customers with a letter explaining work ongoing in their yard.

This continues to be a sound work practice as it was found that completing these tasks prior to the contractor's arrival reduced the amount of time at each injection site and therefore reduced chargeable time by contractors. This practice will now be completed during the Cable Testing Program which will precede the Cable Rehabilitation Program in an area.

- 1/0 Cable Splices: The fewer splices that were present on a cable increased the likelihood of injection. Of the 166 spans of splice free 1/0 cable, 100% were successfully injected. For cable segments with a single splice or segments with 2 or more splices the success rate was as follows with comparison to the prior year.

Program	1 Splice Cable	Success Rate	>1 Splice Cable	Success Rate
2014	59	22%	44	18%
2013	60	35%	19	15%

The drop in success rate could be attributed to a larger volume of buried splice types that are prone to blockages and are not conducive to fluid flow.

- Air Flow Test: If a cable was eligible for low pressure injection, this test was performed to verify injection feasibility. As recommended in the 2013 Cable Injection Pilot Project Report, a pretest for air flow will be performed during the testing program to identify suitable locations for injection and eliminate cable that is blocked at in ground splices.

- Medium Pressure Injections: The medium pressure method was preferred by Manitoba Hydro crews as no outage was required on dead front equipment, the cable injection was completed in one visit and no return for follow up work to the injection site was required. This method also offered the maximum 40 year warranty.

- Warranty: All cable preparation work was completed with contractor approved tools to maintain full warranty.

- Tan-Delta Testing: This 15 minute test was performed by High Voltage Insulation Testing alongside the Injection Program for 2014. A separate report will be provided with results of this testing and recommendations for this program going forward.

A number of processes were identified as having a negative impact on the overall project, which are as follows:

- Splices in Transformers: These splices are at or just above ground level and the injection process requires replacing these with a longer splice body. Some locations were too low and splice replacement was not possible, therefore injection of 1.8km of cable was not completed. Consideration will be given to expose selected cables with water excavation to replace the splice.

- Splices: Any line with one or more splices present continue to have a very low probability of a successful injection. Cables with 1 splice had a 22% successful injection rate with 2 or more spliced cables at 18.2%. With the establishment of the Cable Testing Program these cables will be pre-identified before injection takes place. Consideration will be given to expose selected cables with water excavation to replace splices based on suitable locations.

- Follow Up Work: Low pressure injection requires numerous return visits to site in order to verify the completion of the process and to monitor vacuum bottle pressure. As this method requires days or weeks for fluid to permeate the cable, sections of cables will experience outages where live front equipment is present. Novinium's live front injections required a second outage to re-silicon tape the cable terminations. Medium pressure injection was used wherever possible to minimize the time spent at each site, which in turn reduced labour and contractor costs.

- Manpower: Base crew compliment of 4 journeymen was sufficient for basic operations but proved insufficient over long term with regards to arranging customer interruptions, organizing work and material, reporting and providing minimum manpower for switching operations. A 5th Journeyman added to the crew from April to October would be an asset to allow current Chargehand to more efficiently oversee, plan, and provide assistance to crew.

- Cable Test Time: The 3 tests performed (Tan Delta testing, TDR testing and air-flow testing of cable) required 25 minutes on average to perform. The tests provide beneficial information to the injection program, but deduct at least 1 cable injection per day. Over the course of the 63 day program this would account for approximately 6km of cable worked on or injected. The establishment of the Cable Testing Program for 2015 will address this issue by pretesting cable before the injection season starts.

9. VARIANCES

There were several variances to the 2014-2015 Cable Rehabilitation Program.

- Work Schedule: There were delays that resulted in the loss of several weeks to the start of the program. The creation of the new tender, approval by purchasing, and awarding of the tender due to the complicated nature of the calculating matrix. With a defined program end date due to weather there was no opportunity to make up this lost time. This additional time would have allowed the program to meet its 35km target.

- Manitoba Hydro Cost: Crew included one E level apprentice whose charge out time worked out to a combined 795.6 hours for $71455.20. Underground Program Coordinator also changed 265.2 hours for $14320.80. These 2 figures primarily account for the overages in budget.

- Contractor Cost: Lower cost can be attributed to later program start date resulting in the loss of several weeks for injections. Another contributing factor was a higher percentage (3%) of failed injections due to blockages in buried splices and less material utilized than forecasted.

10. CONCLUSIONS

That based upon the success rate, cost and timelines, the Cable Rehabilitation Program continues to be a viable alternative to cable replacement for the mitigation of end of life XLPE underground cables.

In 63 days, 25.4km of cable was rehabilitated which compares to over 2 years of cable replacement at the aforementioned 12km per year rate. The requirement to not utilize Manitoba Hydro departments of Engineering Design, Surveys, Property, Underground Construction Installation and Termination crews represents a significant cost and time savings.

11. RECOMENDATIONS

Between the months of April and November of each year the Cable Rehabilitation Program will rejuvenate 70-100km of underground XLPE cable annually. By comparison this would represent 8 years of direct cable replacement at historical rates & represents an 85% shorter timeframe.

Distribution Assets Maintenance has initiated an Underground Cable testing program to determine the condition of this asset. This program will test 100-150km annually of cables that are candidates for cable rehabilitation based on cable fault history. Data will be collected and stored in a database with information available in eGIS. Utilizing data from the Cable Testing Program, cables will be classified into categories and recommendations for mitigation be made as follows:

- All 15kv XLPE cable with minimal insulation degradation be deferred and retested in 5 years. Consideration to inject cables will be based on critical service & reliability merits.

- All 15kv XLPE cable with mild to severe insulation degradation be rehabilitated utilizing either injection method. Cables that are blocked at a splice will be considered for injection provided splices are in a suitable location to be excavated and replaced.

- All 15kv XLPE cable with mild to severe insulation degradation, but cannot be injected due to splice blockages, be direct replaced with TRXLPE cable.

A cable rehabilitation pilot program for 2015-2016 be instituted outside of the city of Winnipeg to explore the feasibility of Silicon Injection in rural cities and townships.

The Tender process to go forward as a one year tender with two (2) separate one (1) year options to renew the agreement.

The Urban Winnipeg Rehabilitation Customer Service Operation Crew utilize 5 Journeymen to provide greater coverage for all aspects of the Silicon Injection program.

APPENDIX A
Cost Summary

Novinium Inc

Labour Costs	hours	$/hour	Total
1/0 cable Labour	1,032.5	$ 92.00	$ 94,990.00
O/T costs (total $)	138	$ 138.00	$ 19,044.00
Mobilization Cost	0	$ 5,352.11	$ -
TDR & Material Training	0	$ 5,961.70	$ -
Cable Injection Training	0	$ 4,295.34	$ -
			$ 114,034.00

Injection Costs	meters	$/meter	Total
1/0 meters	25421	$ 12.79	$ 325,134.59
			$ 325,134.59

Material Costs	units	$/unit	Total
1/0 IA	42	$ 50.00	$ 11,752.44
Injection Elbow	36	$ 110.00	$ 11,356.56
			$ 23,109.00

	Novinium Inc	Manitoba Hydro	Combined
Labour Cost	$ 114,034.00	$ 328,178.30	$ 442,212.30
Total Injection Cost	$ 325,134.59	$ -	$ 325,134.59
Overhead	$ -	$ 92,369.02	$ 92,369.02
Material Cost	$ 23,109.00	$ 22,432.80	$ 45,541.80
Subtotal	**$ 462,277.59**	**$ 442,980.12**	**$ 905,257.71**
GST	$ 23,113.88	$ -	$ 23,113.88
US Dollar Conversion	$ 59,831.64	$ -	$ 69,831.64
Total	**$ 545,223.11**	**$ 442,980.12**	**$ 988,203.23**
cost/meter	$ 21.45	$ 17.43	$ 38.87

APPENDIX B
Injection Summary

Project Segments	Total		Project Meters	Total	
medium pressure	166	59.3%	medium pressure	20115	50.3%
low pressure	21	7.5%	low pressure	5306	13.3%
cables tested only	11	3.9%	Cables tested only	1782	4.5%
cables to replace	82	29.3%	cables to replace	12773	32.0%
Injected	**187**	**66.8%**	**Injected**	**25421**	**63.6%**
Totals	**280**		**Totals**	**39976**	

1/0 Cables Segments	Total	1/0 Cables Meters	Total
splice free cables injected	166	splice free cables injected	20155
1 splice injected	13	1 splice injected	2914
2 splice injected	7	2 splice injected	1759
3 splice injected	1	3 splice injected	633
4 splice injected	0	4 splice injected	0
Total	**187**	**Total**	**25421**

1 splice cable failure	46	1 splice cables failed	6372
2 splice cable failure	26	2 splice cables failed	4279
3 splice cable failure	7	3 splice cables failed	1513
4 splice cable failure	1	4 splice cables failed	210
5 splice cable failure	2	5 splice cables failed	399
Total	**82**	**Total**	**12773**

Total splice free injected	166	Total splice free injected	61.7%
Total splice cable injected	21	Total splice cable injected	7.8%
Total spliced cable failed	82	Total spliced cable failed	30.5%
Total	**269**	**Total**	

	Pass	Fail	
1 splice injected	22.0%	78.0%	1 splice cable failure

	Pass	Fail	
2+ splice injected	18.2%	81.8%	2+ splice cable failure

APPENDIX C
Cable Segment Summary

Injected Cables	Segments		Meters	
1/0 medium pressure	166	59.3%	20115	50.3%
1/0 low pressure	21	7.5%	5306	13.3%
	187	**66.8%**	**25421**	**63.6%**

Failed Cables	Segments		Meters	
Low splices	11	3.9%	1783	4.5%
cables to replace	82	29.3%	12772	31.9%
	93	**33.2%**	**14555**	**36.4%**

Totals	**280**	**39976**

Medium Pressure Injections

Sending	Receiving	length (m)
736266	736264	52
736268	736266	67
736270	736268	53
738300	738248	151
738248	738262	113
736272	736274	53
736274	736276	38
736280	736278	46
738302	738296	81
738302	738304	80
738258	738250	141
738258	738260	67
738264	738260	83
738298	738296	77
736254	736252	68
736258	736254	80
738286	738282	76
738286	738288	63
738290	738288	106
738293	738292	38
738292	738294	86
737669	737665	115
737665	737661	110

Low Pressure injections

Sending	Receiving	length (m)	Splices
738300	736270	310	1
736276	736278	83	1
736282	736262	90	1
738304	738306	87	1
738250	738306	79	1
736252	738298	224	2
737555	737570	365	1
736336	736338	195	1
736324	736328	321	1
736322	736320	372	1
736310	736314	353	1
738176	738271	509	2
738273	738281	362	1
738270	738276	170	2
735683	dc 03-7	166	2
735982	735984	190	2
739391	739478	371	2
739399	739397	129	2
739500	739413	633	3
739448	739447	181	1
793443	793444	116	1

Medium Pressure

Sending	Receiving	length (m)
736376	736375	67
738284	738282	120
738284	738280	229
738280	738278	104
738278	738252	189
737670	737668	117
737666	737668	72
738254	738252	93
738254	738256	179
738266	738268	101
737666	737664	84
737664	737662	67
737662	737660	105
737659	737656	113
735649	735652	117
735649	735646	157
738209	738207	80
738209	738211	121
738213	738211	171
738213	738215	42
738201	738203	90
735643	735646	106
735643	735640	115
738205	738203	189
737572	737570	67
738606	738612	83
738612	738614	127
737568	737566	275
737566	737564	245
737557	737555	99
737557	737559	131
738616	738614	150
738804	738622	148
737336	737334	166
736332	736334	100
736332	736330	99
738626	738806	158
738806	738818	161
738800	738812	152
736324	736322	120

Failed Segments

Sending	Receiving	length (m)	Splices
736272	736264	295	2
736282	736280	56	1
736258	736257	63	2
738290	738293	179	1
736376	737669	123	1
737661	737655	94	2
JP 005-7	736375	58	1
JP 005-7	736370	54	1
738256	738255	121	1
737656	737658	76	2
737660	737659	94	1
738205	738207	55	1
737568	737572	196	1
738616	738622	120	1
738808	738804	110	1
738610	738624	75	1
738602	738600	210	4
738626	738604	189	1
736328	736330	305	1
738620	738618	82	2
738620	738800	124	3
737562	737559	95	1
738824	738822	124	1
736312	736314	142	1
738279	738275	318	2
738272	738270	140	1
dc 03-7	738276	647	3
736203	736201	111	1
DC 7-7	736257	108	1
DC 7-7	738294	189	1
735986	735678	138	1
738161	738166	98	1
735730	735728	138	1
735683	735685	137	5
738174	735691	211	1
739401	739393	64	3
735698	735697	78	2
738178	735692	201	2
738178	735693	87	2
735694	735693	109	2

Medium Pressure			Failed	Segments		
Sending	**Receiving**	**length (m)**	**Sending**	**Receiving**	**length (m)**	**Splices**
736318	736320	160	735694	735695	125	2
736318	736316	264	735696	735695	169	2
737562	737560	106	735696	735697	179	2
738824	738828	129	739408	739424	122	1
738814	738882	78	737658	CP 591660	262	5
736312	736316	245	737655	CP 591660	299	3
DC 12-7	738262	72	736370	CP 591575	97	1
DC 12-7	738264	121	739428	739426	119	2
DC12-7	738266	166	739426	739430	80	2
738279	738281	241	739430	739422	130	1
738814	738810	97	738215	CP 591480	71	1
738810	738802	99	738201	CP 519480	85	1
738273	738271	159	739448	739422	242	2
738272	738274	148	739412	739406	107	2
736203	736206	64	DC 30-7	739461	191	1
739476	739478	100	739565	JP 009-7	554	1
739476	739474	105	736286	736302	63	2
739465	739474	469	736220	736222	64	1
738465	739467	141	736220	736218	77	2
739455	739417	150	736232	736218	173	2
739455	739457	139	736232	736231	74	1
739457	739459	155	736227	736228	63	1
739415	739417	101	736227	736222	175	3
739469	739467	160	736229	736228	76	1
735986	735988	109	736220	736218	77	2
735880	735678	100	736222	736220	64	1
738161	738163	172	739471	739473	58	1
738164	738163	199	735962	735954	238	2
735680	738164	138	735962	735960	84	2
735738	735736	151	735960	735968	176	1
735682	735738	71	739433	739434	89	1
735734	735736	156	739484	739439	131	2
735734	735732	127	739444	739445	46	1
735730	735732	107	739449	739445	122	2
735691	735690	73	739449	739446	113	1
735686	735685	47	739486	739517	84	1
739391	739393	52	739486	739507	140	3
739399	739401	50	739482	739517	64	3
739413	739415	93	739580	739487	273	1
739411	739463	90	793403	CP 591750	564	1

Medium Pressure		
Sending	**Receiving**	**length (m)**
739461	739463	77
735687	735686	152
735687	735688	71
735689	735688	175
739411	739409	81
735689	735690	127
735684	735699	76
735699	735698	113
739409	739407	154
739405	739407	122
739406	739408	70
739428	739424	71
735640	CP591475	91
735652	CP591475	51
739090	DC 34-7	136
739090	DC 34-7	136
739090	DC 34-7	136
737483	CP591655	58
737483	CP591655	58
737483	CP591655	58
DC 30-7	739459	104
DC 30-7	739469	101
739565	739562	75
739562	739559	83
739559	739556	108
739479	739556	114
739479	739477	134
739475	739477	90
736300	736302	91
736286	736290	86
736296	736238	111
736296	736294	206
736229	736231	59
739473	739475	216
736244	736242	71
736954	736976	179
735968	735966	102
JP 9-7	739577	284
739427	739435	83
739427	739429	91

Failed	Segments		
Sending	**Receiving**	**length (m)**	**Splices**
739397	CP 591750	890	2
739421	739420	148	1

Medium	Pressure	
Sending	**Receiving**	**length (m)**
739431	739429	116
739481	739550	48
739433	730431	68
739484	739480	96
739443	739441	48
738553	739571	178
739574	739571	131
739574	739577	120
JP 9-7	739586	315
739497	739499	218
739499	739502	176
739502	739504	157
739580	739583	272
739513	739511	156
739419	739412	175
739513	739509	261
739511	CP550680	261
739493	CP550680	159
739497	CP550680	61
739500	CP591750	91
739421	739423	106
739423	739425	57
739405	739403	87

APPENDIX D
Cable Type Summary

Average By Cable Type

Manufacturer		Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
Canada Wire		21.9	53.9	10.9	86.7	1.5	115.6	0.75	1.33
Pirelli		25.7	57.0	7.8	90.5	1.5	117.3	0.77	1.30
Unknown		27.8	74.8	7.8	110.4	1.8	136.3	0.81	1.23
Superlink		19.1	155.1	11.2	185.3	3.1	150.6	1.23	0.81
Phillips		35.3	78.4	13.8	127.5	2.1	101.6	1.26	0.80
Northern Electric		20.8	42.8	17.6	81.2	1.4	52.6	1.54	0.65
166	**Total**	**3653**	**14493**	**1713**	**19859**	**331**	**20115**	**0.99**	**1.01**
	Average	**22.0**	**87.3**	**10.3**	**119.6**	**2.0**	**121.2**		

Northern Electric - Compressed Conductor

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
736266	736264	50	56	24	130	2.2	52	1.08	0.93
736268	736266	30	60	15	105	1.8	67	0.90	1.12
736270	736268	12	58	20	90	1.5	53	1.09	0.91
736272	736274	7	18	20	45	0.8	53	0.34	2.94
736274	736276	5	22	9	36	0.6	38	0.58	1.73
5	**Total**	**104**	**214**	**88**	**406**	**7**	**263**	**1.54**	**0.65**
	Average	**20.8**	**42.8**	**17.6**	**81.2**	**1.4**	**52.6**		

Pirelli - Compressed Conductor

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
737669	737665	14	114	4	132	2.2	115	0.99	1.01
737665	737661	7	102	20	129	2.2	110	0.93	1.08
736376	736375	30	67	11	108	1.8	67	1.00	1.00
735649	735652	25	115	9	149	2.5	117	0.98	1.02
738209	738207	21	2	10	33	0.6	80	0.03	40.00
738209	738211	21	13	10	44	0.7	121	0.11	9.31
738213	738211	31	65	15	111	1.9	171	0.38	2.63
738201	738203	13	8	5	26	0.4	90	0.09	11.25
738205	738203	7	28	7	42	0.7	189	0.15	6.75
737568	737566	10	250	5	265	4.4	275	0.91	1.10
738273	738271	30	60	4	94	1.6	159	0.38	2.65
737483	CP591655	55	10	5	70	1.2	58	0.17	5.80
737483	CP591655	55	5	5	65	1.1	58	0.09	11.60
737483	CP591655	55	10	5	70	1.2	58	0.17	5.80
736300	736302	12	6	2	20	0.3	91	0.07	15.17
15	**Total**	**386**	**855**	**117**	**1358**	**23**	**1759**	**0.77**	**1.30**
	Average	**25.7**	**57.0**	**7.8**	**90.5**	**1.5**	**117.3**		

Phillips - Compressed Conductor

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
736280	736278	17	31	4	52	0.9	46	0.67	1.48
738606	738612	115	57	38	210	3.5	83	0.69	1.46
738612	738614	35	120	15	170	2.8	127	0.94	1.06
738616	738614	20	120	20	160	2.7	150	0.80	1.25
736203	736206	10	11	1	22	0.4	64	0.17	5.82
735880	735678	57	18	36	111	1.9	100	0.18	5.56
735738	735736	15	175	15	205	3.4	151	1.16	0.86
735682	735738	60	25	10	95	1.6	71	0.35	2.84
735734	735732	25	109	6	140	2.3	127	0.86	1.17
739461	739463	10	75	10	95	1.6	77	0.97	1.03
739090	DC 34-7	50	150	5	205	3.4	136	1.10	0.91
739405	739403	10	50	5	65	1.1	87	0.57	1.74
12	**Total**	**424**	**941**	**165**	**1530**	**26**	**1219**	**1.26**	**0.80**
	Average	**35.3**	**78.4**	**13.8**	**127.5**	**2.1**	**101.6**		

Unknown Cable (unable to read information from cable)

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
736258	736254	12	23	7	42	0.7	80	0.29	3.48
737566	737564	10	116	9	135	2.3	245	0.47	2.11
737557	737555	21	30	10	61	1.0	99	0.30	3.30
737557	737559	15	59	1	75	1.3	131	0.45	2.22
738804	738622	60	210	17	287	4.8	148	1.42	0.70
736254	736252	16	21	7	44	0.7	68	0.31	3.24
738626	738806	30	195	10	235	3.9	158	1.23	0.81
738806	738818	25	155	10	190	3.2	161	0.96	1.04
738279	738281	9	117	10	136	2.3	241	0.49	2.06
738161	738163	39	36	10	85	1.4	172	0.21	4.78
738164	738163	52	21	5	78	1.3	199	0.11	9.48
735680	738164	58	32	5	95	1.6	138	0.23	4.31
735730	735732	30	45	5	80	1.3	107	0.42	2.38
735691	735690	29	20	5	54	0.9	73	0.27	3.65
736296	736238	45	50	5	100	1.7	111	0.45	2.22
736296	736294	5	110	5	120	2.0	206	0.53	1.87
736229	736231	25	7	14	46	0.8	59	0.12	8.43
739423	739425	20	99	5	124	2.1	57	1.74	0.58
18	**Total**	**501**	**1346**	**140**	**1987**	**33**	**2453**	**0.81**	**1.23**
	Average	**27.8**	**74.8**	**7.8**	**110.4**	**1.8**	**136.3**		

Superlink - Compact Conductor

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
735649	735646	19	140	40	199	3.3	157	0.89	1.12
735643	735646	20	100	30	150	2.5	106	0.94	1.06
735643	735640	10	107	23	140	2.3	115	0.93	1.07
737336	737334	13	80	7	100	1.7	166	0.48	2.08
736332	736334	10	30	3	43	0.7	100	0.30	3.33
736332	736330	13	25	7	45	0.8	99	0.25	3.96
738800	738812	30	265	10	305	5.1	152	1.74	0.57
736318	736316	25	255	5	285	4.8	264	0.97	1.04
737562	737560	30	65	15	110	1.8	106	0.61	1.63
738824	738828	25	118	22	165	2.8	129	0.91	1.09
738814	738882	20	160	10	190	3.2	78	2.05	0.49
736312	736316	33	222	5	260	4.3	245	0.91	1.10
738814	738810	30	75	20	125	2.1	97	0.77	1.29
738810	738802	25	75	5	105	1.8	99	0.76	1.32
738465	739467	10	144	5	159	2.7	141	1.02	0.98
739455	739417	30	230	10	270	4.5	150	1.53	0.65
739455	739457	5	220	15	240	4.0	139	1.58	0.63
739415	739417	10	185	10	205	3.4	101	1.83	0.55
739469	739467	12	123	2	137	2.3	160	0.77	1.30
735734	735736	15	210	20	245	4.1	156	1.35	0.74
739391	739393	5	24	1	30	0.5	52	0.46	2.17
739413	739415	11	114	15	140	2.3	93	1.23	0.82
739411	739463	20	94	16	130	2.2	90	1.04	0.96
739411	739409	10	65	10	85	1.4	81	0.80	1.25
739409	739407	10	246	9	265	4.4	154	1.60	0.63
739405	739407	10	25	10	45	0.8	122	0.20	4.88
739406	739408	13	44	5	62	1.0	70	0.63	1.59
739428	739424	17	40	5	62	1.0	71	0.56	1.78
735640	CP591475	27	95	1	123	2.1	91	1.04	0.96
735652	CP591475	30	90	1	121	2.0	51	1.76	0.57
739090	DC 34-7	30	174	5	209	3.5	136	1.28	0.78
739090	DC 34-7	30	174	5	209	3.5	136	1.28	0.78
DC 30-7	739459	10	95	5	110	1.8	104	0.91	1.09
DC 30-7	739469	23	132	5	160	2.7	101	1.31	0.77
739562	739559	5	50	10	65	1.1	83	0.60	1.66
739559	739556	15	75	15	105	1.8	108	0.69	1.44
739479	739556	11	92	8	111	1.9	114	0.81	1.24
739479	739477	23	217	18	258	4.3	134	1.62	0.62
739475	739477	10	78	12	100	1.7	90	0.87	1.15

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
739473	739475	25	170	10	205	3.4	216	0.79	1.27
JP 9-7	739577	30	270	5	305	5.1	284	0.95	1.05
739481	739550	25	14	1	40	0.7	48	0.29	3.43
738553	739571	20	95	5	120	2.0	178	0.53	1.87
739574	739571	5	100	5	110	1.8	131	0.76	1.31
739574	739577	10	90	5	105	1.8	120	0.75	1.33
JP 9-7	739586	5	225	5	235	3.9	315	0.71	1.40
739497	739499	25	334	15	374	6.2	218	1.53	0.65
739499	739502	3	242	28	273	4.6	176	1.38	0.73
739502	739504	28	177	15	220	3.7	157	1.13	0.89
739580	739583	30	260	5	295	4.92	272	0.96	1.05
739513	739511	26	220	5	251	4.2	156	1.41	0.71
739419	739412	5	260	5	270	4.5	175	1.49	0.67
739513	739509	25	195	5	225	3.8	261	0.75	1.34
739511	CP550680	15	357	13	385	6.4	261	1.37	0.73
739493	CP550680	13	242	17	272	4.5	159	1.52	0.66
739497	CP550680	7	60	17	84	1.4	61	0.98	1.02
52	**Total**	**992**	**8064**	**581**	**9637**	**161**	**7829**	**1.23**	**0.81**
	Average	**19.1**	**155.1**	**11.2**	**185.3**	**3.1**	**150.6**		

Canada Wire - Compressed Conductor

Sending	Receiving	Preparation minutes	Injection minutes	Pressurization minutes	Total injection time (min)	Hours	Cable length (m)	Fluid flow min/meter	Fluid Flow meter/min
738300	738248	20	196	19	235	3.9	151	1.30	0.77
738248	738262	20	30	6	56	0.9	113	0.27	3.77
738302	738296	8	44	2	54	0.9	81	0.54	1.84
738302	738304	14	47	2	63	1.1	80	0.59	1.70
738258	738250	17	43	13	73	1.2	141	0.30	3.28
738258	738260	8	17	7	32	0.5	67	0.25	3.94
738264	738260	10	22	10	42	0.7	83	0.27	3.77
738298	738296	16	64	9	89	1.5	77	0.83	1.20
738286	738282	14	36	7	57	1.0	76	0.47	2.11
738286	738288	15	20	10	45	0.8	63	0.32	3.15
738290	738288	8	72	8	88	1.5	106	0.68	1.47
738293	738292	30	14	8	52	0.9	38	0.37	2.71
738292	738294	12	36	10	58	1.0	86	0.42	2.39
738284	738282	35	40	10	85	1.4	120	0.33	3.00
738284	738280	15	125	5	145	2.4	229	0.55	1.83
738280	738278	14	30	15	59	1.0	104	0.29	3.47
738278	738252	15	80	20	115	1.9	189	0.42	2.36
737670	737668	20	75	15	110	1.8	117	0.64	1.56
737666	737668	30	33	32	95	1.6	72	0.46	2.18

738254	738252	23	5	4	32	0.5	93	0.05	18.60
738254	738256	15	25	8	48	0.8	179	0.14	7.16
738266	738268	28	7	6	41	0.7	101	0.07	14.43
737666	737664	15	30	15	60	0.8	84	0.36	2.80
737664	737662	15	35	5	55	1.7	67	0.52	1.91
737662	737660	5	95	10	110	1.8	105	0.90	1.11
737659	737656	20	110	15	145	2.4	113	0.97	1.03
738213	738215	17	3	3	23	0.4	42	0.07	14.00
737572	737570	20	10	10	40	0.7	67	0.15	6.70
736324	736322	30	45	10	85	1.4	120	0.38	2.67
736318	736320	40	90	10	140	2.3	160	0.56	1.78
dc 12-7	738262	47	7	6	60	1.0	72	0.10	10.29
dc 12-7	738264	6	36	8	50	0.8	121	0.30	3.36
dc12-7	738266	10	35	10	55	0.9	166	0.21	4.74
738272	738274	11	12	12	35	0.6	148	0.08	12.33
739476	739478	10	22	5	37	0.6	100	0.22	4.55
739476	739474	11	29	5	45	0.8	105	0.28	3.62
739465	739474	5	168	5	178	3.0	469	0.36	2.79
739457	739459	10	165	15	190	3.2	155	1.06	0.94
735986	735988	15	125	15	155	2.6	109	1.15	0.87
735686	735685	35	45	5	85	1.4	47	0.96	1.04
739399	739401	10	20	10	40	0.7	50	0.40	2.50
735687	735686	5	65	10	80	1.3	152	0.43	2.34
735687	735688	30	15	5	50	0.8	71	0.21	4.73
735689	735688	128	15	7	150	2.5	175	0.09	11.67
735689	735690	60	20	10	90	1.5	127	0.16	6.35
735684	735699	45	10	15	70	1.2	76	0.13	7.60
735699	735698	55	10	15	80	1.3	113	0.09	11.30
739565	739562	23	32	5	60	1.0	75	0.43	2.34
736286	736290	28	26	13	67	1.1	86	0.30	3.31
736244	736242	10	20	5	35	0.6	71	0.28	3.55
736954	736976	30	90	5	125	2.1	179	0.50	1.99
735968	735966	30	60	5	95	1.6	102	0.59	1.70
739427	739435	10	52	13	75	1.3	83	0.63	1.60
739427	739429	6	58	27	91	1.5	91	0.64	1.57
739431	739429	11	84	11	106	1.8	116	0.72	1.38
739433	730431	15	26	10	51	0.9	68	0.38	2.62
739484	739480	11	50	4	65	1.1	96	0.52	1.92
739443	739441	7	11	39	57	1.0	48	0.23	4.36
739500	CP591750	10	222	18	250	4.2	91	2.44	0.41
739421	739423	13	64	5	82	1.4	106	0.60	1.66
57	**Total**	**1246**	**3073**	**622**	**4941**	**83**	**6592**	**0.75**	**1.33**
	Average	**21.9**	**53.9**	**10.9**	**86.7**	**1.5**	**115.6**		

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	Page No.:	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please explain the significant increase in sustaining capital expense over the past ten years.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

Manitoba Hydro notes that capital spending over the 10 year period from 2005 to 2014 exhibited a compound annual growth rate of approximately 3.6% as shown in the schedule below.

Manitoba Hydro's asset management and capital prioritization processes have enabled the Corporation to defer hundreds of millions of dollars of capital investment to date. This has been accomplished through numerous maintenance programs and refurbishment programs to extend the functional life of its assets.

Notwithstanding Manitoba Hydro's successful asset management practices, increased investment is now required to sustain the Corporation's electric infrastructure considering the increasing pressures associated with aging infrastructure and the need to provide more capacity to support the growth requirements of Manitoba Hydro's customers.

This increase through the test years is primarily related to:

- Replacement of the existing 24kV distribution at St. Vital station due to equipment rating concerns and customer-driven demand;
- Construction of the new Adelaide station to meet capacity requirements and to allow for the decommissioning of the King station;
- Increased capital investment for urban and rural station development to address overloaded substations and feeder development;
- Increased capital investment for aging plant including poles, underground cables, streetlights and manholes;
- Continued major overhaul work on the Pine Falls and Great Falls units to address aging infrastructure;
- Continued construction of the new Rockwood 230-115kV station to address capacity constraints;
- Continued construction of the new Madison 115-24kV station due to aging plant;
- Improvements to the Lake Winnipeg East System to address capacity constraints.

	Actual										Compound Annual Growth 2005-2014
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	%
Electric Sustaining Capital	342.0	313.3	363.0	357.5	349.0	405.4	442.6	465.2	432.7	470.1	3.6

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	**Page No.:**	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please update figure 4.11 incorporating the base capital spending forecast in CEF09, CEF10 , CEF11, CEF12 and CEF 13 for the respective years . Please provide a table of data points.

RATIONALE FOR QUESTION:

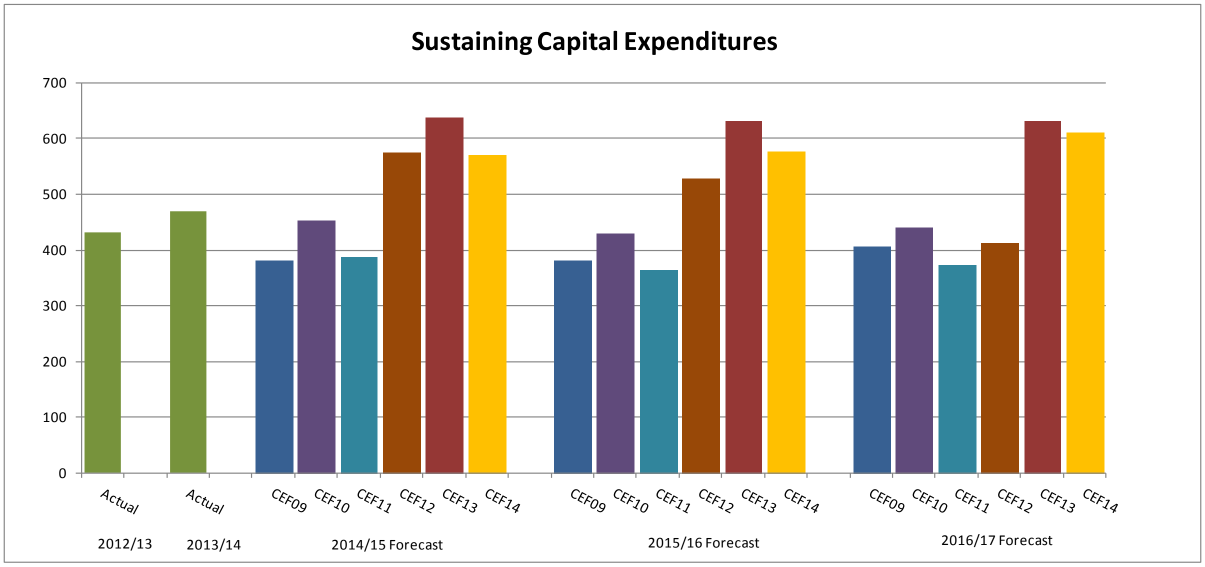
Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

Please see the following table and charts with respect to sustaining capital and DSM expenditures.

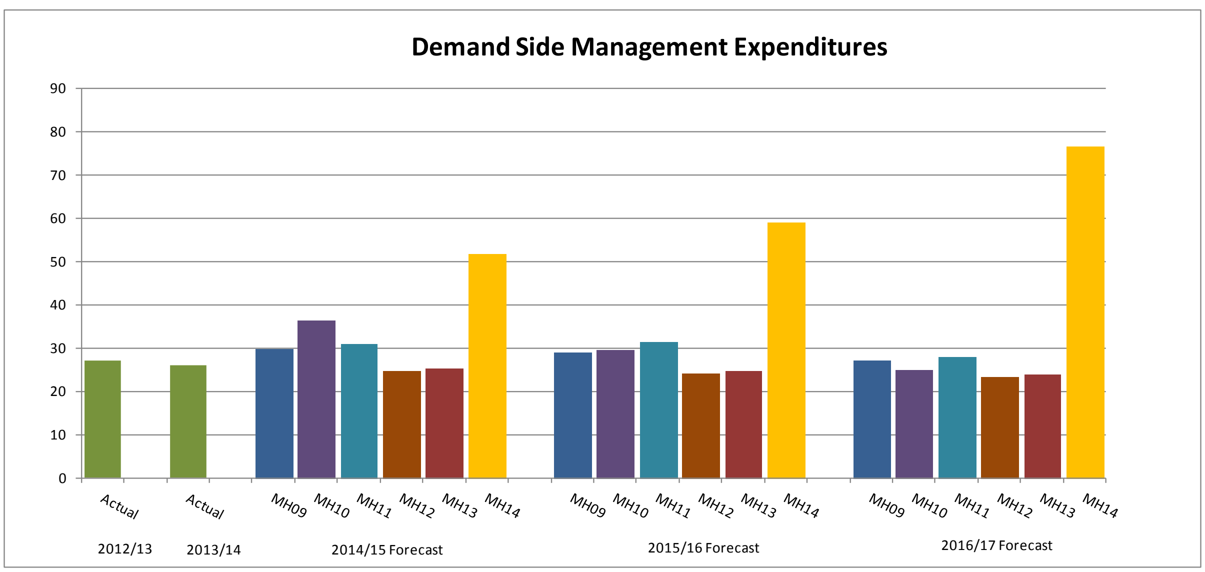
Sustaining Capital Expenditures (in millions)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Actual	433	470			
CEF09			382	381	406
CEF10			452	430	440
CEF11-2*			387	364	372
CEF12*			574	529	414
CEF13			637	631	632
CEF14			571	577	610

*Includes IFRS OH Adjustment



DSM Expenditures (in millions)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Actual	27	26			
MH09			30	29	27
MH10			36	30	25
MH11*			31	31	28
MH12*			25	24	23
MH13			25	25	24
MH14			52	59	77

* Assumed no continuation of rate regulated accounting and expensed under IFRS.



Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	Page No.:	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please separate Figure 4.12 to major versus base capital to reconcile with CEF 14.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

The following schedule provides a breakdown of Figure 4.12 to major versus base capital. This view was developed for filing purposes to supplement the Electric Infrastructure Condition Assessment report and is an approximation as Manitoba Hydro's financial system tracks capital expenditures by cost and depreciation categories, not Asset Type.

CEF14 Sustaining Capital by Asset Type	Major	Major	Major	Base	Base	Base
(in millions of dollars)	2015	2016	2017	2015	2016	2017
Generation Operation						
Turbines	10.0	10.4	13.2	9.7	3.0	2.6
Generators	14.2	12.0	19.4	0.2	5.8	0.7
Auxiliary Systems (Sewer, Water, Fire, etc)	1.9	0.7	0.5	10.5	9.6	12.0
Transformers	0.4	0.5	2.1	12.0	6.9	5.8
Licensing	-	-	-	10.4	10.8	8.3
Instrumentation & Controls	0.9	1.3	5.9	8.1	13.8	5.9
Townsite Infrastructure	-	-	-	8.9	10.4	5.0
Breakers	-	-	-	8.9	4.3	1.3
Spillway & Water Controls	0.9	1.4	8.8	6.5	12.1	15.3
Powerhouse, Dams, Dykes	2.7	1.2	5.4	4.0	6.4	2.7
Physical Security & Public Safety	0.5	-	-	4.8	3.2	2.0
AC Supporting Electrical Systems	1.0	2.9	5.3	4.2	4.7	1.1
Governors	0.5	-	-	4.1	3.9	1.6
Exciters	0.1	-	0.4	2.8	3.5	3.3
Tools & Equipment	-	-	-	2.4	2.2	1.4
Communication Systems & Equipment	-	-	-	1.4	1.2	1.9
	33.1	**30.4**	**61.0**	**98.9**	**101.6**	**71.0**
Transmission						
Station Equipment	0.9	0.9	0.3	15.4	14.4	13.6
Station Civil Infrastructure	13.3	8.4	1.7	2.6	0.7	1.1
Transformers	4.2	3.0	0.7	11.0	9.5	11.9
Communication Systems & Equipment	3.1	1.3	1.7	11.4	5.9	6.9
Protection Relays & Control, Metering & SCADA	6.8	5.0	1.1	7.0	2.2	2.1
HVDC Synchronous Condensers	8.7	8.5	2.7	0.3	0.2	0.2
Steel Structures	4.4	5.1	18.3	2.9	7.3	15.7
Wood Poles	5.6	32.4	13.3	1.1	0.8	0.8
Breakers	1.4	1.0	0.3	5.4	4.3	3.4
Battery Banks	-	-	-	4.0	2.5	1.9
Conductor Attachments	-	-	-	3.6	4.4	5.1
HVDC Valve Group	-	-	-	2.8	0.7	0.1
Tools & Equipment	-	-	-	2.4	1.6	1.4
Land & Easements	0.7	0.3	9.7	1.6	0.8	0.5
Overhead Conductors	1.2	0.9	6.8	0.6	1.4	2.7
System Control Centre	-	-	-	0.4	0.3	0.3
Diesel Generation	-	-	-	0.4	-	-
HVDC Smoothing Reactors	-	-	-	0.1	0.4	0.5
Other	1.6	0.9	0.1	0.2	(0.0)	(0.0)
	51.8	**67.7**	**56.7**	**73.2**	**57.3**	**68.3**
Customer Services & Distribution						
Poles	1.0	0.4	1.2	42.3	38.1	47.1
Overhead Conductors	0.8	-	-	38.4	33.3	33.8
Underground Cables	2.2	6.3	12.3	29.1	31.0	33.2
Station Breakers and Other Station Equipment	10.9	17.7	14.8	12.9	11.9	14.0
Overhead Transformers	0.5	-	-	22.1	18.2	22.2
Station Transformers	9.0	12.6	10.0	12.1	10.5	14.7
Padmount Transformers	1.1	1.0	0.2	16.8	11.2	15.5
Street Lights	0.0	-	-	11.0	10.8	12.8
Ductlines & Manholes	2.7	4.6	1.5	5.2	11.4	11.7
Station Site Prep	3.6	6.6	7.6	2.4	2.6	1.7
Land & Easement	2.7	0.3	-	1.0	0.1	0.0
Buildings	4.0	8.6	11.2	0.4	1.5	1.5
Equipment	-	-	-	1.4	1.2	1.4
Steel Structures	-	-	-	0.8	0.7	-
Other	-	-	-	1.3	-	-
	38.6	**58.2**	**58.7**	**197.0**	**182.6**	**209.6**
Customer Care & Energy Conservation						
Meters & Meter Transformers	-	-	-	3.2	4.0	4.1
	-	**-**	**-**	**3.2**	**4.0**	**4.1**
Human Resources & Corporate Services						
Computers & IT Systems	-	-	-	29.0	29.1	29.6
Buildings	-	-	-	22.4	24.3	9.3
Fleet	-	-	-	21.0	18.9	13.3
Land & Easements	-	-	-	1.7	1.8	1.8
Tools & Equipment	-	-	-	0.9	0.9	0.9
	-	**-**	**-**	**75.0**	**75.0**	**55.0**
Finance Regulatory						
Tools & Equipment	-	-	-	0.2	0.2	0.2
	-	**-**	**-**	**0.2**	**0.2**	**0.2**
Target Adjustment				-	-	25.0
Sustaining Capital Total	**123.4**	**156.4**	**176.4**	**447.4**	**420.7**	**433.1**

Section:	Tab 4: Sustaining Capital Figures 4.11 & 4.12	**Page No.:**	11,12
Topic:	Capital Expenditures		
Subtopic:	Sustaining Capital Expenditures		
Issue:	Target Adjustment		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting rate increases to cover base capital spending.

QUESTION:

Please update figure 4.12 on a similar basis to (b) providing detail of comparative sustaining capital spending shown in CEFs.

RATIONALE FOR QUESTION:

Increases in sustaining capital spending are a major driver around proposed rate increases. This information explores the impact of sustaining capital on rate increases.

RESPONSE:

The information presented in Figure 4.12 was specifically developed for this application to be consistent with Manitoba Hydro's Asset Condition Assessment report. This information is not available in this format for previous years' actual results or previous CEFs. Please see the response to PUB/MH-I-22c.

Section:	Tab 4, App. 4.2	Page No.:	Overall Doc.
Topic:	Capital Expenditures		
Subtopic:	MH's Asset Condition Assessment Ref: PUB Order 150/08, dated Nov 7, 2008		
Issue:	Adequacy of Response to PUB 116/08, amended Directive #7, pp. 69/70		

PREAMBLE TO IR (IF ANY):

Board Order 150/08 provided a directive to Manitoba Hydro with respect to an Asset Condition Assessment. In this GRA, Manitoba Hydro filed an Asset Condition Assessment Report.

QUESTION:

Please elaborate on how Manitoba Hydro has addressed the specific items listed in PUB Directive # 7, namely:

- Major assets and categories of assets
- Estimated remaining economic life of each major asset and category of asset
- An indication of the implications for OM&A costs related to required and scheduled maintenance
- A listing of scheduled, planned or anticipated major upgrading, decommissioning of major assets or categories of assets
- Forecast expenditures of planned renovations and replacements with respect to now available energy supply and transmission
- Dam safety condition assessments and maintenance requirements?

RATIONALE FOR QUESTION:

This question follows up on Directive 7 from Board Order 150/08 and explores a major rationale for Manitoba Hydro’s requested rate increases.

RESPONSE:

PUB Directive #7 in Order 116/08 requested that Manitoba Hydro undertake and file an Asset Condition Assessment Report. Manitoba Hydro continues to manage the integrity and replacement of its assets by way of various management processes that have been established and that continue to evolve. The Electric Infrastructure Condition Assessment Summary ("Summary"), filed in response to this directive in Appendix 4.2 to this Application, provides summary information for the PUB and directly or indirectly addresses the majority of the items identified by the PUB in Directive #7.

The Summary provides an overview of the Corporation's most significant generation, transmission, high voltage direct current (HVDC) and distribution assets which are identified as either major assets or categories of assets.

The Summary describes Manitoba Hydro's electric infrastructure in terms of asset categories, each of which has an impact on the overall integrity of Manitoba Hydro's electric system. The quantity of assets within each of the 29 categories is illustrated in section 4 of the Summary.

The remaining economic life of an asset is only one consideration in the replacement of the asset. The condition of asset categories is quantified using an Asset Health Index ("AHI"). The index quantifies plant condition based on numerous parameters that are related to the long-term degradation factors that may lead to an asset's end of life. An AHI is intended to provide a measure of long-term degradation, which is one indicator of the asset's overall health, and should reflect the likelihood that an asset will fail and necessitate a forced replacement or refurbishment. However, ultimately when Manitoba Hydro is considering the replacement of assets, such decisions are made upon an overall assessment of risk which not only includes asset health but also considers remaining economic life, safety, environmental, and customer needs including provision of reliable service.

Manitoba Hydro's Summary, through the AHI scoring of its asset categories, implies that OM&A costs related to required and scheduled maintenance will increase as assets degrade from a very good condition toward a very poor condition. The magnitude of required OM&A costs required to sustain the life of each asset category is dependent on many factors including the physical characteristics of the asset and suitable maintenance programs available to prolong the life of an asset.

This type of information is taken into consideration during the capital prioritization process to identify appropriate capital projects and programs that will mitigate the risks associated with aging electric assets. These projects and programs are represented in the capital expenditure forecasts.

Scheduled, planned or anticipated major upgrades, including a decommissioning of major assets or asset categories or the planning of renovations and replacements with respect to existing energy supply and transmission, are contained within capital investment forecasts.

Manitoba Hydro's Summary is not intended to address dam safety condition assessments and maintenance requirements, as those matters are managed through other corporate processes. Annual dam safety condition assessments are undertaken by internal staff and consultants. Dam Safety Reports, by station, are prepared and condition assessments of earth dams and concrete structures are scored. Based on these assessments, work is identified to maintain these systems within guidelines identified by the Canadian Dam Association.

Section:	Tab 4, App. 4.2	**Page No.:**	Overall Doc.
Topic:	Capital Expenditures		
Subtopic:	MH's Asset Condition Assessment Ref: PUB Order 150/08, dated Nov 7, 2008		
Issue:	Adequacy of Response to PUB 116/08, amended Directive #7, pp. 69/71		

PREAMBLE TO IR (IF ANY):

Board Order 150/08 provided a directive to Manitoba Hydro with respect to an Asset Condition Assessment. In this GRA, Manitoba Hydro filed an Asset Condition Assessment Report.

QUESTION:

Provide Manitoba Hydro’s working papers with respect to the items listed in (a) and the individual assets considered in Appendix 4.2.

RATIONALE FOR QUESTION:

This question follows up on Directive 7 from Board Order 150/08 and explores a major rationale for Manitoba Hydro’s requested rate increases.

RESPONSE:

The supporting materials for the Electric Asset Condition Assessment Summary (Appendix 4.2) are provided in the following Appendices to that report:

- Appendix A: Definitions and Acronyms
- Appendix B: Generation Operations Detailed Methodology
- Appendix C: Transmission Detailed Methodology
- Appendix D: Distribution Detailed Methodology

Section:	Tab 4, App. 4.2	**Page No.:**	Overall Doc.
Topic:	Capital Expenditures		
Subtopic:	MH's Asset Condition Assessment Ref: PUB Order 150/08, dated Nov 7, 2008		
Issue:	Adequacy of Response to PUB 116/08, amended Directive #7, pp. 69/72		

PREAMBLE TO IR (IF ANY):

Board Order 150/08 provided a directive to Manitoba Hydro with respect to an Asset Condition Assessment. In this GRA, Manitoba Hydro filed an Asset Condition Assessment Report.

QUESTION:

To the extent the specific items in (a) have not been addressed yet, indicate when/how they will be addressed.

RATIONALE FOR QUESTION:

This question follows up on Directive 7 from Board Order 150/08 and explores a major rationale for Manitoba Hydro's requested rate increases.

RESPONSE:

Manitoba Hydro's Electric Infrastructure Condition Assessment Summary Report has addressed the items either directly or indirectly, with the exception of Dam Safety, as noted in Manitoba Hydro's response to PUB/MH-I–19a.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Please detail the reasons for the cost increases to Bipole III. In particular, please detail the reasons for the cost increases to the converter stations and the decision to add synchronous condensers.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

The table below provides a comparison of the capital cost of Bipole III from CEF12 to CEF14. Material variances are explained below.

MANITOBA HYDRO
BIPOLE III PROJECT COMPARISON

(in millions of $)

Project	**CEF 12**	**CEF 14**	**Inc/(Dec)**
Transmission Lines	$ 1,259.9	$ 1,655.4	$ 395.5
Converter Stations	1,828.5	2,675.1	846.6
Collector Lines	191.4	260.2	68.8
Community Development Initiative	-	62.0	62.0
Total	**$ 3,279.8**	**$ 4,652.7**	**$ 1,372.9**

The increase to the project cost of Bipole III versus the previous approved amount has been driven by several factors as discussed below:

1. **The finalization of the HVDC Converters contract and resulting need for Synchronous Condensers:**

   The largest contributing factor to the increase in the Bipole III Control Budget was the final fixed pricing received for the HVDC Converters Equipment and the direct current converter technology selected. Vendors were given the freedom to offer Line Commuted Conversion (LCC) technology or Voltage Source Converter (VSC) technology based upon their own technical and risk assessment of the work. All bids received by Manitoba Hydro recommended the reliable and proven LCC technology. The LCC technology requires the use of synchronous condensers. As a result, converters and related equipment costs came in higher than the estimate which had assumed the use of VSC technology.

2. **The finalization of the Transmission Line route and subsequent route adjustments based on the CEC recommendations:**

   The items related to the Transmission Line route were preliminary and not yet finalized in the previous budget. The 2014 Bipole III Control Budget incorporates all costs associated with the finalization of the Transmission Line route and incorporates all project Licence requirements as recommended by the Clean Environment Commission.

   The finalized Transmission Line route has been adjusted to minimize environmental and agricultural impacts of the transmission line. This includes adjustments to help protect caribou and their habitats, protect and reduce effects on mineral resources and mining interests, minimize effects on agriculture, and minimize effects on landowners. The impact of these adjustments increases the length, turns and bends in the line and constrains tower placements requiring additional stronger and heavier structures. This includes 31 route adjustments and approximately 200 additional towers.

3. Increase in the capacity of the converter equipment to 2300 MW:

Bipole III converter equipment rating was increased to 2300 MW (from 2000 MW) to ensure sufficient capacity for future generation development and flexibility to take advantage of emerging export opportunities. The increased cost for capacity is marginal in comparison to the costs that would be incurred to add this additional transmission capacity at a later date.

4. Incorporation of Awarded Contract Amounts:

In addition to the inclusion of the awarded, fixed price contract amount for the HVDC Converter Equipment, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised Control Budget.

5. Revised In-Service Date:

The previous Bipole III budget assumed an October 2017 in-service date (ISD) for the project. Delays in obtaining the Licence and subsequent delays in obtaining environmental and work permits resulted in Manitoba Hydro having construction delayed by a year and a half. As a result of the delays, the ISD was updated to July 2018 which impacts interest and escalation costs.

6. Increased Project Contingency and Reserves:

A complete risk and contingency review was conducted as part of establishing the revised 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. A revised P50 contingency and Management Reserve fund were developed.

7. Funds Associated with the Community Development Initiative (CDI):

Funds associated with the Community Development Initiative (CDI) have been included within the revised $4.65B Bipole III Control Budget.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Advise whether all land acquisition and mitigation costs for the Bipole III corridor are included in the $4.65B estimate. If not, provide a breakdown of what is and what is not included.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

All land acquisition and compensation costs are included within the $4.65B Control Budget for Bipole III. This Control Budget includes the project contingency.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Advise what percentage of land acquisition cost has been firmed up and what remains outstanding, and indicate the geographic areas where land acquisition cost has not yet been determined.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

Approximately 90% of the land for Bipole III has been secured. As such, the risk of additional costs for land acquisition is minimal.

The remaining lands to be secured are in the Southern portion of the Province.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Provide a detailed breakdown of the project costs, including details of each awarded contract document and pending tender documents.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

Approximately 70% (by $ value) of the contracts on Bipole III have been awarded or are in final negotiations. The total value of awarded contracts as of December 31, 2014 is within the overall control budget. Please refer to Figure 4.7 on page 8 of 26 from Tab 4 of the GRA filing for a breakdown of Bipole III project costs.

A further break-down of contract values is commercially sensitive as several major contracts are still to be awarded and providing such a breakdown could provide bidders with information on amounts remaining in the budgets for the remainder of the contracts.

Information on contracts awarded or in final stages of negotiations is as follows:

- Over 90% (by $ value) of contracts for the Riel and Keewatinohk Converter Stations have been awarded or are in final negotiations
- Over 45% (by $ value) of contracts for the 500kV Transmission Line have been awarded or are in final negotiations
- Over 90% (by $ value) of contracts for the AC Collector Lines have been awarded or are in final negotiations

Section:	Tab 4, App. 4.1	Page No.:	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Provide the capital project justifications for Bipole III and the required converter stations for the last 4 years.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

Please see the attached capital project justifications for each component of Bipole III issued over the last 4 years, as per the list below.

List of attachments

	Title	Addendae	1st CEF Version
Attachment 1	Bipole III Project TRANSMISSION LINE	Addendum Number 06a	CEF11-2
Attachment 2	Bipole III Project CONVERTER STATIONS	Addendum Number 06b	CEF11-2
Attachment 3	Bipole III Project COLLECTOR LINES	Addendum Number 06c	CEF11-2
Attachment 4	Community Development Initiative	Original	CEF13
Attachment 5	Bipole III Project TRANSMISSION LINE	Addendum Number 07a	CEF14
Attachment 6	Bipole III Project CONVERTER STATIONS	Addendum Number 07b	CEF14
Attachment 7	Bipole III Project COLLECTOR LINES	Addendum Number 07c	CEF14
Attachment 8	Bipole III Project COMMUNITY DEVELOPMENT INITIATIVE	Addendum Number 07d	CEF14

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFIC
FOR

Bipole III Western Routed T/L & 2000MW Converters
TRANSMISSION LINE
Addendum Number 06a

REVIEWED BY:
(Owning Dept Manager) Ron Mazur 2011/03/30

NOTED BY:
(if applicable)

Coordinating Div: S. Bailey 2011/03/30

Constructing Div:

Designing Div.:

Financial: Nieuwenburg 2011.03.30

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G Neufeld 2011 03 30

Business Unit V.P.: [illegible] 2011 . 03 . 30

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,081,923,000
REVISED BUDGET $: (Total Net Cost)	$1,259,915,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.2.1.1.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14518

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Project Owner: Pei Wang
Project Manager: Adele Poulin

DATE PREPARED: 2011.03.30

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).

Increase the budget by $177,991,000 for the Transmission Line components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $1,259,915,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the HVdc transmission line, and of the licensing and environmental assessment for the overall complex (total increase of $152,122,000);
- inclusion of contingency for the above-mentioned components (total increase of $49,353,000); and
- the resultant changes to interest and escalation (decrease of $23,485,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinoow Converter Station to the Riel Converter Station, approximately 1341km in length.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).
- Property acquisition and/or easements for the 500kV HVdc transmission line.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, addressed an increase of 45km to the length of the transmission line, as well as increases being experienced in transmission line material and construction costs due to market prices. The cost estimates for licensing, property and contingency were not updated at that time.

This CPJ Addendum #06a covers a budget increase of $177,991,000 in association with the Transmission Line components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>500kV HVdc Transmission Line (base increase of $140,714,000):</u>
   - Design change from double to triple conductor, in order to lower the surface field gradient to accepted worldwide practices and thus minimize the likelihood of anomalous flashovers that have been experienced on the existing bipoles in the past 20 years.
   - Incorporation of the Transmission Line Agreement for unionization of construction labour.
   - Application of the revised corporate policy for compensation for private property.

b) <u>Licensing & Environmental Assessment for the Bipole III complex (base increase of $4,912,000):</u>
   - More comprehensive aboriginal and community consultations.
   - Additional studies related to converter size.

Background (This section is be filled out only if there is information relevant to the recommendation).

c) Property Acquisition and/or Easements for the Transmission Line (base increase of $6,497,000):
- More privately-owned land associated with the western route.

d) The revised budget also includes contingency at $49,353,000 (Project Risk Analysis section contains details).

The above changes to the base estimate and contingency, and a change in base dollars from 2007 to 2010, result in a net decrease of $23,485,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	**NPV Benefits (Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits (Costs)**

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $49,353,000 of contingency (approximately 6% of the base estimate) is included in the budget amount for CPJ Addendum #06a, to cover the following:

a) 500kV HVdc Transmission Line (contingency of $39,967,000 or 5% of the base estimate):
Potential changes to the detailed route selection or line length.

b) Licensing & Environmental Assessment (contingency of $9,386,000 or 15% of the base estimate):
Potential for greater requirements for aboriginal and community consultations, and for more extensive environmental monitoring and assessments during construction.

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The following risks create a potential for additional costs:
- Market conditions for transmission line construction labour, materials or commodities.
- Unforeseen geotechnical conditions.
- Further changes to corporate policy for private property compensation.

Some of the schedule-related risks associated with meeting an October 2017 in-service are as follows:
- Environmental License to be received by September 2012.
- Certain activities will need to proceed in parallel with the environmental licensing process:
  - acquiring permits to work on crown lands,
  - purchase of some materials and/or purchase of extra towers and foundations types to accommodate unexpected conditions due to lack of geotechnical information,
  - temporary permits for site investigation activities (including field drilling) in order for design of foundations to be finalized and materials ordered for the construction start date.
- Completion of the northern portion of the line is based on having five winter seasons for access and construction.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 17,207	$ 24,613	$ 7,406
2010/11	$ 5,801	$ 16,118	$ 10,317
2011/12	$ 10,235	$ 24,830	$ 14,595
2012/13	$ 146,630	$ 59,866	$ (86,764)
2013/14	$ 181,825	$ 162,043	$ (19,782)
2014/15	$ 201,556	$ 298,935	$ 97,379
2015/16	$ 216,344	$ 318,454	$ 102,110
2016/17	$ 227,477	$ 234,575	$ 7,098
2017/18	$ 71,665	$ 120,055	$ 48,390
2018/19	$ 3,184	$ 426	$ (2,758)
2019/20	$ -	$ -	$ -
Total	$ 1,081,923	$ 1,259,915	$ 177,991

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).
No change.

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFICA[TION] FOR

Bipole III Western Routed T/L & 2000MW Converters
CONVERTER STATIONS
Addendum Number 06b

REVIEWED BY:
(Owning Dept Manager)

BA FOR RME

NOTED BY:
(if applicable)

Coordinating Div:

Constructing Div:

Designing Div.:

Financial:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,104,197,000
REVISED BUDGET $: (Total Net Cost)	$1,828,532,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

11 03 30

OWNING DIVISION: NEW GENERATION CONSTRUCTION

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY:

DATE PREPARED: 2011.03.29

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Western Routed T/L & 2000MW Converters – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).

Increase the budget by $724,335,000 for the Riel and Keewatinoow Converter Station components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $1,828,532,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the Riel and Keewatinoow Converter Stations and 230kV Switchyards (total increase of $474,226,000);
- inclusion of contingency for the above-mentioned components (total increase of $138,926,000); and
- the resultant changes to interest and escalation (increase of $111,183,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of the 2000 MW Riel Converter Station and 230kV AC Switchyard.
- Design and construction of the 2000 MW Keewatinoow Converter Station and 230kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinoow Converter Stations.

The proposed budget assumes use of voltage source converters for both the Riel and Keewatinoow Converter Stations without synchronous condensers at the Riel Converter Station.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, did not include re-estimates for the converter stations, nor was contingency included for the converter stations, as these components had not yet been reviewed in detail.

This CPJ Addendum #06b covers a budget increase of $724,335,000 in association with the Riel and Keewatinoow Converter Station components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>Riel Converter Station and 230kV AC Switchyard (base increase of $169,355,000):</u>
   - Converter and HVdc equipment costs have remained relatively unchanged when comparing 2009 mini-spec pricing versus the escalated 2001 estimate figures; however, there were no explicit indirect costs in the 2001 estimate and no interfacing costs.

b) <u>Keewatinoow Converter Station and 230kV AC Switchyard (base increase of $286,069,000):</u>
   - Converter and HVdc equipment costs have remained relatively unchanged when comparing 2009 mini-spec pricing versus the escalated 2001 estimate figures; however, there were no explicit indirect costs in the 2001 estimate and no interfacing costs.

Background (This section is be filled out only if there is information relevant to the recommendation).

- Site development costs have increased for the following reasons: the previous budget assumed that the Conawapa Generating Station infrastructure would be built ahead of Bipole III and therefore costs associated with a construction camp and work areas would be covered by that project's budget; mechanical services such as fire, water, sewer and oil containment, along with security and environmental requirements, were not considered in the 2001 estimate; the site size has increased and soil conditions are worse than identified in the 2001 estimate; the transformer change-out method and the emergency response buildings were not included in the 2001 estimate.

c) Property Acquisition and/or Easements for the Converter Stations (base increase of $18,802,000): Property costs for Riel and Keewatinoow Converter Stations were not included in the 2001 estimate. Costs for the Riel site are more substantial than the Keewatinoow site, and include $6.4 million for station site properties, and $12.3 million for buffer properties that have been purchased from private owners.

In addition to the above, the revised budget also includes the introduction of contingency at $138,926,000 (Project Risk Analysis section contains details).

The changes to the base estimate and inclusion of contingency, along with the change in base dollars from 2007 to 2010, result in an increase of $111,183,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of aDorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $138,926,000 of contingency (approximately 11% of the base estimate) is included in the budget amount for CPJ Addendum #06b, to cover the following:

a) Keewatinoow Converter Station and 230kV AC Switchyard (contingency of $71,960,000 or 12% of the base estimate):
   - Potential changes to equipment costs due to a limited number of suppliers worldwide and variability of exchange rates until contracts are signed.
   - Potentially higher costs due to northern work conditions.

b) Riel Converter Station and 230kV AC Switchyard (contingency of $66,966,000 or 11% of the base estimate):
   - Potential changes to equipment costs due to limited number of suppliers worldwide and variability of exchange rates until contracts are signed.
   - Uncertainty with protection, cyber security and building strength (physical security).

The following risks create a potential for additional costs:
- Potential for greater requirement for engineering, project management and construction management.
- Potential for poor site conditions during construction.
- The potential requirement for synchronous condensers at the Riel Converter Station.

The assumed use of new technology in the form of voltage source converters at both the Keewatinoow and Riel Converter Stations represents an additional risk factor. Confirmation or otherwise of the feasibility of this technology is expected by late 2011.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 4,243	$ 30,423	$ 26,181
2010/11	$ 6,812	$ 46,255	$ 39,443
2011/12	$ 14,092	$ 59,696	$ 45,604
2012/13	$ 24,477	$ 148,883	$ 124,406
2013/14	$ 141,783	$ 300,258	$ 158,475
2014/15	$ 207,019	$ 290,185	$ 83,166
2015/16	$ 344,041	$ 294,281	$ (49,759)
2016/17	$ 291,378	$ 308,460	$ 17,082
2017/18	$ 70,351	$ 347,692	$ 277,341
2018/19	$ -	$ 2,398	$ 2,398
2019/20	$ -	$ -	$ -
Total	$ 1,104,197	$ 1,828,532	$ 724,335

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

D1876(A)

REVIEWED BY EXECUTIVE COMMITTEE
MINUTE # 1348.02

DATE: 2011 03 31
Financial Planning

CAPITAL PROJECT JUSTIFIC
FOR

Bipole III Western Routed T/L & 2000MW Converters
COLLECTOR LINES
Addendum Number 06c

REVIEWED BY:
(Owning Dept Manager: Ron Mazur) Ron Mazur 2011/03/30

NOTED BY:
(if applicable)

Coordinating Div: Shane Mailey S. Mailey 2011/03/30

Constructing Div:

Designing Div.:

Financial: [signature] 2011.03.30

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: G Neufeld 2011 03 30

Business Unit V.P.: [signature] 2011.03.30

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$61,715,000
REVISED BUDGET $: (Total Net Cost)	$191,438,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 points)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: TRANSMISSION PLANNING & DESIGN

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534 - P:15537, P:15542, P:15543, P:15696, P:15697

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Project Owner: Pei Wang
Project Manager: Adele Poulin

DATE PREPARED: 2011.03.30

REPORT NUMBER:

FILE NUMBER (Optional):

05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Western Routed T/L & 2000MW Converters – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Increase the budget by $129,722,000 for the Collector Lines components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex, to a revised total of $191,438,000, in order to incorporate the following:

- review of the base estimate for the property, design and construction of the 230kV collector lines for the Keewatinoow Converter Station, the construction power for the Keewatinoow Converter Station, the sectionalization of 230kV transmission line R49R at the Riel Converter Station, and the electrode lines for the Riel and Keewatinoow Converter Stations (total increase of $73,222,000);
- inclusion of contingency for the above-mentioned components (total increase of $17,203,000); and
- the resultant changes to interest and escalation (increase of $39,297,000).

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction of three permanent and two temporary 230kV collector lines for the Keewatinoow Converter Station.
- Construction power substation for the Keewatinoow Converter Station.
- Design and construction for the Riel and Keewatinoow electrode lines.
- Sectionalization of 230kV transmission line R49R at Riel.
- Property acquisition and/or easements for the collector and electrode lines.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was preliminary only, pending completion of studies by System Planning. It was based on an estimate prepared by Teshmont Consultants in 2001.

CPJ Addendum #05, submitted in May 2007, did not include re-estimates for the northern collector lines, the two electrode lines, the related property, or contingency.

This CPJ Addendum #06c covers a budget increase of $129,722,000 in association with the Collector Lines components of the Bipole III Western Routed Transmission Line & 2000MW Converters complex:

a) <u>Keewatinoow 230kV Collector Lines (base increase of $35,756,000):</u>
The 2001 estimate included only three collector lines, while this estimate has two more (temporary) collector lines. The two temporary lines are required in lieu of an earlier introduction of additional generation in the northern collector system. At the time of the 2001 estimate, the planned in-service for the Conawapa Generating Station (GS) was only two years after Bipole III. Now that the in-service for Conawapa GS is planned for several years later, two temporary lines are required in order to permit full use of a 2000MW rating for Bipole III in the event of a Dorsey Station or Bipole I / II outage.

In addition, the cost of transmission line material and construction has increased since 2001.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) Keewatinoow Construction Power (base increase of $23,381,000):
The 2001 estimate did not include the requirement for a construction power substation, as it was assumed it would have already been built for construction of the Conawapa GS. With the change in the sequence, the Bipole III project will now be the first development to require this construction power substation.

c) Property Acquisition and/or Easements for the Collector and Electrode Lines (base increase of $10,732,000):
The 2001 estimate did not include any property costs for the Keewatinoow collector lines or the Riel and Keewatinoow electrode lines.

d) Sectionalization of 230kV Transmission Line R49R at Riel (base increase of $1,955,000):
This had been included in the Riel Sectionalization project but was deferred to coincide with the Bipole III converters. It is required to accommodate and reliably transmit a 2000MW Bipole III at Riel.

e) Riel and Keewatinoow Electrode Lines (base increase of $1,398,000):
The cost of line material and construction has increased since 2001.

f) The revised budget also includes contingency at $17,203,000 (Project Risk Analysis section contains details).

The above changes to the base estimate and contingency, and a change in base dollars from 2007 to 2010, result in an increase of $39,297,000 to forecasted escalation and interest.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is required for all Addendums).

A third 500kV HVdc transmission line with converter stations rated for 2000MW will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	For current corporate rates see G911

Recommended Option	NPV Benefits (Costs)
No change.	

Other Alternatives Considered	NPV Benefits (Costs)

Project Risk Analysis - (This section is be filled out only if there is a change to the project risk).

A total of $17,203,000 of contingency (approximately 15% of the base estimate) is included in the budget amount for CPJ Addendum #06c, to cover the following:

a) Keewatinoow Collector Lines (contingency of $8,952,000 or 13% of the base estimate): Provides for potentially higher costs for material and construction labour.

b) Keewatinoow Construction Power (contingency of $5,451,000 or 23% of the base estimate): Estimates are based on a conceptual Single Line Diagram only. The site size and exact location are not yet finalized. Backup power requirements are currently under review.

c) Riel and Keewatinoow Electrode Lines (contingency of $2,800,000 or 34% of the base estimate): Line lengths are uncertain, as the Electrode sites for Riel and Keewatinoow have not been finalized. Also provides for use of steel towers if necessary for reliability.

The following risks create a potential for additional costs:
- Potential for poor site conditions during construction.
- Potentially higher costs due to northern work conditions.
- Further changes to corporate policy for private property compensation.

Capital Budget Estimate - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 237	$ 0	$ (237)
2010/11	$ 381	$ 2,121	$ 1,740
2011/12	$ 788	$ 19,917	$ 19,130
2012/13	$ 1,368	$ 52,709	$ 51,341
2013/14	$ 7,924	$ 30,141	$ 22,217
2014/15	$ 11,571	$ 30,927	$ 19,357
2015/16	$ 19,229	$ 34,255	$ 15,026
2016/17	$ 16,286	$ 13,549	$ (2,737)
2017/18	$ 3,932	$ 7,818	$ 3,886
2018/19	$ -	$ -	$ -
2019/20	$ -	$ -	$ -
Total	$ 61,715	$ 191,438	$ 129,722

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).
No change.

Reference Documents (This section is be filled out only if changed).
No change.

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1453.03
DATE: 2013 08 20
Financial Planning

CAPITAL PROJECT JUS... FOR

Community Development Initiative

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.: ERKristjanson 2013/08/15

BUDGET $: (Total Net Cost)	$60,782,000
START DATE: (1st Cost Flow)	2014 03
IN-SERVICE DATE: (Last Major In-service Date)	2017 10
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	Tier 2 (950 points)
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: Aboriginal Relations

I.M. NODE NUMBER: 1.5.2.1.1.2

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Louis Demers

DATE PREPARED: 2013 07 19

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☒ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Project Name
Bipole III Community Development Initiative – **TRANSMISSION LINE**

Recommendation
Establish budget to incorporate Bipole III Community Development Initiative ("CDI") that was approved by the Manitoba Hydro-Electric Board in May 2010.

Project Scope
Estimate based on the net present value of a 10-year program valued at up to $6 million per year.

Background

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03). Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

The requested budget increase is planned as a 2013/14 expense based on all regulatory approvals being received no later than December 2013.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals
The CDI program remains inclusive of a variety of interests; is strongly linked to the Bipole III facilities; and will be an effective means of promoting community support for hosting the Bipole III project facilities.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	For current corporate rates see G911 %	For clarification on hurdle rates, contact the Economic Analysis Department

Recommended Option	**NPV Benefits (Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A	

Risk Analysis

No change.

Capital Budget Estimate

The annual net budget requirements are as follows (in thousands of dollars):

Fiscal Year	Proposed Budget
Prev. Actuals	$ -
2013/14	$ 53,937
2014/15	$ 2,157
2015/16	$ 1,979
2016/17+	$ 2,709
Total	$ 60,782

Proposed Schedule

No change.

Related Projects

No change.

Reference Documents

Executive Committee Board Recommendation for the "Bipole III Community Development Initiative" (document approved under EC minute # 913-10-06 - plus revision of August 12, 2013 (revising the distance from the line to 40km) EC minute # pending.

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AD FOR

Bipole III Project
TRANSMISSION LINE
Addendum Number 07a

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/01

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,259,915,000
REVISED BUDGET $: (Total Net Cost)	$1,655,371,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.1.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).
Increase the budget by $395 million for the Transmission Line components of the Bipole III Project, to a revised total of $1,655 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:
- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk (Keewatinoow) Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).

Changes to scope include: revised line length of final approved route, issued Licence & Conditions, revised landowner compensation strategy and policy, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based on a preferred routing of the line prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. Also since the last estimate, the project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line and change to project in-service of July 2018.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for market uncertainty risk for transmission line construction work.

<u>P50 Estimate:</u>

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $363 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Changes to the finalized route (increased length, additional towers and increased right-of-way width)
- Updated land acquisition costs
- Recommended contingency of $110M (increase of $61M) to address remaining uncertainty. See

Background (This section is be filled out only if there is information relevant to the recommendation).
Risk Analysis section. <u>Reserves:</u> A Management Reserve has been established to address significant risks related to bidding market and pricing uncertainty for Transmission Line construction work (increase of $100M). See Risk Analysis section. <u>In-Service Costs:</u> The overall increase to the in-service cost of the project is $395M (31%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).
A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system). The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).
The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

Additionally, this portion of the Bipole III Project includes a recommended Management Reserve of $100M associated with bidding market and pricing uncertainty for Transmission Line construction work. This remains the greatest area of uncertainty for Bipole III and the potential cost variation associated with this risk is best addressed through the inclusion of Management Reserve funds.

An additional, significant area of uncertainty is the potential impacts to schedule due to further delays in acquisition of private lands. A Management Reserve for this risk has not been recommended as part of the project budget. However, there will be cost impacts to the project should the risk occur.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 24,613	$ 24,613	$ -
2010/11	$ 16,118	$ 19,002	$ 2,884
2011/12	$ 24,830	$ 18,350	$ (6,480)
2012/13	$ 59,866	$ 25,091	$ (34,775)
2013/14	$ 162,043	$ 54,276	$ (107,767)
2014/15	$ 298,935	$ 203,458	$ (95,477)
2015/16	$ 318,454	$ 360,455	$ 42,001
2016/17	$ 234,575	$ 381,047	$ 146,472
2017/18	$ 120,055	$ 493,821	$ 373,766
2018/19	$ 426	$ 75,257	$ 74,831
Total	$ 1,259,915	$ 1,655,371	$ 395,456

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A
FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 07b

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
[signature] 2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: [signature] 2014/10/02

Business Unit V.P.: [signature] 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,828,532,000
REVISED BUDGET $: (Total Net Cost)	$2,675,083,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.2.1

W.B.S. NUMBERs: P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).
Increase the budget by $ 846.5 million for the Converter Station components of the Bipole Project, to a revised total of $2,675 and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:
- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.

Changes to scope include: Selection of LCC HVdc technology requiring the inclusion of Synchronous Condensers, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based largely on historical and budgetary pricing from vendors as well as an assumption of VSC technology for the HVdc Converter and therefore no requirement for synchronous condensers.

The revised estimate is based on LCC HVdc technology as this was the technology bid by all vendors and incorporates the bid pricing received. The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>
Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $649 million to the P50 Estimate as a result of the following:

- Incorporation of contract costs for the Keewatinohk 230kV AC Switchyard, Keewatinohk Site Development, Keewatinohk Camp and Keewatinohk Camp Services
- Incorporation of bid price for the Keewatinohk and Riel HVdc Converter Equipment contract
- Inclusion of Synchronous Condensers in the scope of work as a result of LCC technology for the HVdc equipment
- Incorporation of allocated portion of actual costs for Riel Sectionalization project
- Incorporation of updated costs for the Riel 230kV AC Switchyard Expansion

Background (This section is be filled out only if there is information relevant to the recommendation).
• Recommended contingency of $119.6M (decrease of $16M) to address remaining uncertainty. Reserves: No Management Reserve for the Converter Stations component of the project is recommended to include in the estimate at this time. In-Service Costs: The overall increase to the in-service cost of the project is $846.5 (46%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).
A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system). The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).
The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty. Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 30,423	$ 30,423	$ -
2010/11	$ 46,255	$ 28,069	$ (18,186)
2011/12	$ 59,696	$ 36,417	$ (23,279)
2012/13	$ 148,883	$ 79,718	$ (69,165)
2013/14	$ 300,258	$ 144,153	$ (156,105)
2014/15	$ 290,185	$ 221,051	$ (69,134)
2015/16	$ 294,281	$ 580,792	$ 286,511
2016/17	$ 308,460	$ 828,733	$ 520,273
2017/18	$ 347,692	$ 507,689	$ 159,997
2018/19	$ 2,399	$ 195,085	$ 192,686
2019/20	$ -	$ 18,432	$ 18,432
2020/21	$ -	$ 4,520	$ 4,520
Total	$ 1,828,532	$ 2,675,083	$ 846,551

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A[
FOR

Bipole III Project
COLLECTOR LINES
Addendum Number 07c

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: Bruce Barrett 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$191,438,000
REVISED BUDGET $: (Total Net Cost)	$260,150,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P:20790, P:21201, P:23816

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ Customer Service
- ☐ System Supply
- ☐ Efficiency
- ☒ System Reliability
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).

Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).

Increase the budget by $68.7 million for the Collector Lines components of the Bipole III Project, to a revised total of $260.2 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:

- Design and construction of three permanent and two temporary 230 KV collector lines for the Keewatinohk (Keewatinoow) Converter Station.
- Construction power substation, 138 KV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station.
- Design and construction of the Riel and Keewatinohk electrode lines.
- Sectionalization of 230 KV transmission line R49R at Riel and associated modifications at Ridgeway and Rosser stations.
- Property acquisition and/or easements for the above components.
- Design and construction of a new bay and modifications at existing Long Spruce 230 KV AC switchyard for the new collector line to Keewatinohk Converter Station.
- Design and construction of a new bay and modifications at existing Henday 230 KV AC switchyard for the four new collector lines to Keewatinoow Converter Station.
- Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Changes to scope include: the issued Licence & Conditions, double circuit requirement for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts, inclusion of Long Spruce and Henday 230 KV station expansions/modifications, inclusion of breaker replacements, and revised schedule and project in-service date to July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2009/10, based on conceptual scope of collector line components, prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, increased scope (new items in this component), as well as up-to-date market information. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>
Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. In addition, new items were included in the current scope for this component.

Background (This section is be filled out only if there is information relevant to the recommendation).

This resulted in an increase of $83 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Change to include a double circuit requirement for the Keewatinoow to Long Spruce AC collector line
- Incorporation of increased reliability design for both electrode lines
- Change to assume Clearing, 230kV AC transmission line construction and Construction Power contracts as Direct Negotiated Contracts (DNCs)
- Inclusion of new items – Long Spruce and Henday 230 KV station expansions/modifications and breaker replacements projects
- Recommended contingency of $18M (increase of $800K) for this component, to address remaining uncertainty. See Risk Analysis section.

Reserves:
No Management Reserve for the Collector Lines components is recommended to include in the estimate at this time. See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project for this component is $68 M (36%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date and increase in the recommended contingency. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No change.	

Capital Project Justification Addendum

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 0	$ 0	$ -
2010/11	$ 2,121	$ 386	$ (1,735)
2011/12	$ 19,917	$ 2,075	$ (17,842)
2012/13	$ 52,709	$ 4,394	$ (48,315)
2013/14	$ 30,141	$ 26,265	$ (3,876)
2014/15	$ 30,927	$ 58,432	$ 27,505
2015/16	$ 34,255	$ 75,516	$ 41,261
2016/17	$ 13,549	$ 51,722	$ 38,173
2017/18	$ 7,819	$ 36,708	$ 28,889
2018/19	$ -	$ 4,653	$ 4,653
Total	$ 191,438	$ 260,150	$ 68,711

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AI FOR

Bipole III Project
COMMUNITY DEVELOPMENT INITIATIVE
Addendum Number 07d

REVIEWED BY:
(Owning Dept Manager)
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:
2014/10/14

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$60,782,000
REVISED BUDGET $: (Total Net Cost)	$61,954,000
START DATE: (1st Cost Flow)	2014 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.7.1

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 26

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

-	2001 06 13	Original CPJ	E.R. Kristjanson	Executive Committee (Minute #1453.03)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **COMMUNITY DEVELOPMENT INITIATIVE (CDI)**

Recommendation (This section is required for all Addendums).
Increase the budget by $1.2 million for the Bipole III Community Development Initiative ("CDI") fund, that was approved by the Manitoba Hydro-Electric Board in May 2010, to a revised total of $62.0 million

Project Scope (This section is be filled out only if there is a change to the scope).
Community Development Initiative ("CDI") fund for Manitoba Hydro to provide benefits to communities in vicinity of the Bipole III Project

Background (This section is be filled out only if there is information relevant to the recommendation).

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03).

Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

Justification (This section is required for all addendums).
The CDI program remains inclusive of a variety of interests; is required as part of Bipole III; and will be an effective means of promoting community support for hosting the Bipole III project facilities

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No Change	

Other Alternatives Considered	NPV Benefits/(Costs)
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

No Change.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ -	$ -	$ -
2013/14	$ 53,937	$ 53,863	$ (73)
2014/15	$ 2,157	$ 2,291	$ 134
2015/16	$ 1,979	$ 1,979	$ -
2016/17	$ 1,787	$ 1,787	$ -
2017/18	$ 922	$ 1,581	$ 659
2018/19	$ -	$ 453	$ 453
Total	$ 60,782	$ 61,954	$ 1,172

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

Identify any additional reference documents (relative to those already listed in the previous CPJ/Addendum) that support or provide background on this recommendation.

Section:	Tab 4, App. 4.1	Page No.:	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Provide a status report on contingencies/reserve and acquisition and mitigation costs.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

Contingency and reserve amounts included within the Bipole III Control Budget total $347.6 million. Of this amount, approximately $27.4 million has been expended as part of mitigating project risks. Therefore, approximately 92% of the project contingency and reserve fund is remaining.

Please refer to responses PUB/MH-I-20b and PUB/MH-I-20c for responses on property acquisition costs.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14
Topic:	Capital Expenditures		
Subtopic:	Manitoba-Minnesota 500kV Transmission line		
Issue:	The Great Northern Transmission Line Project		

PREAMBLE TO IR (IF ANY):

MH has committed to funding 67% of the Great Northern Transmission project capital cost and a large portion of the annual OM&A costs. It isn't clear how these costs are included in IFF 14.

QUESTION:

Provide the specific IFF 14 line items (Finance, Depreciation, OM&A and Taxes) that go to MH's financial obligations to Minnesota Power with respect to the US Great Northern Transmission project.

RATIONALE FOR QUESTION:

To gain understanding of Manitoba Hydro’s financial obligations in respect of the line.

RESPONSE:

Please see Appendix 11.15 Financial Information MFR 9.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14
Topic:	Capital Expenditures		
Subtopic:	Manitoba-Minnesota 500kV Transmission line		
Issue:	The Great Northern Transmission Line Project		

PREAMBLE TO IR (IF ANY):

MH has committed to funding 67% of the Great Northern Transmission project capital cost and a large portion of the annual OM&A costs. It isn't clear how these costs are included in IFF 14.

QUESTION:

Please file any CPJs for the past three years for each of the Manitoba portion of the Manitoba/Minnesota transmission line and the U.S. Great Northern Transmission project.

RATIONALE FOR QUESTION:

To gain understanding of Manitoba Hydro's financial obligations in respect of the line.

RESPONSE:

Please find attached the capital project justification for the Manitoba-Minnesota 500kV Transmission Line. Prior to CEF14, this item was named Dorsey-US Border 500kV Transmission Line.

In August 2014, Manitoba Hydro approved entering into an agreement with Minnesota Power for the sale and purchase of surplus energy for twenty years. The Corporation also approved funding of up to $0.5 billion USD for the development and construction of the Great Northern Transmission Line (GNTL) with Minnesota Power and is recognized as an Intangible Asset in the forecasted electric operations statements. The forecast for this item is included in Manitoba Hydro's cash flow requirements statement under the Investing Activities PP&E category and not in Capital Expenditure Forecast (CEF14).

The estimated carrying and operating costs are included in Appendix 11.15, Financial Information, MFR 9.

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Dorsey – US Border New 500 kV Transmission

Addendum Number 01

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1453.03

DATE: 2013 08 20
Financial Planning

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

130813

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$204,764,000
REVISED BUDGET $: (Total Net Cost)	$350,346,000
START DATE: (1st Cost Flow)	2010 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2018 05
REVISED ISD: (Last Major In-service Date)	2019 10
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: Power Planning

I.M. NODE NUMBER: 1.5.2.4.2.1

W.B.S. NUMBERs: P:16957, P:16958, P:16959, P:16961, P:16962, P:21180, P:21616

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: C.R. Winstone

DATE PREPARED: 2013 07 31

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☒ System Supply
- ☐ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
001	2013 05 13	Update Costs for Manitoba Portion of new line	CRW	

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Dorsey – US Border New 500 kV Transmission Line

Recommendation (This section is required for all Addendums).
Increase the budget from $204.8 M to $350.3 M to reflect updated costs for equipment to terminate line at Riel and Dorsey and communication equipment.

Project Scope (This section is be filled out only if there is a change to the scope).
A change in scope includes a Phase Shifting transformer at the Glenboro station to control North Dakota-Manitoba loop flow.

Background (This section is be filled out only if there is information relevant to the recommendation).
The need for phase shifting transformers has only recently been identified, and is a$21.5 M increase in scope from the original CPJ. The project in-service date has changed from 2018 05 to 2019 10 reflecting the current sales negotiations with Minnesota Power and Wisconsin Public Service.

Justification (This section is required for all addendums).
This project has been included in resource plans since the 2008/09 Power Resource Plan. It is required to meet export sales to Wisconsin Public Service and Minnesota Power.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	**For current corporate rates see G911**	**For clarification on hurdle rates, contact Economic Analysis Department**

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**
List each alternative considered as well as its calculated NPV.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).
The design of the transmission line is dependent on the final negotiations of potential sales with Wisconsin Public Service and Minnesota Power, and potentially others. Final design could consist of only 230 kV line,

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

if only Minnesota Power consummates the sale. Conversely, Manitoba Hydro may be required to own a share of the US portion of the line if a 500 kV line is constructed.

Not constructing this line in time for the WPS Sale would result in either a smaller 230 kV line being constructed to serve only the 250 MW MP Sale, or potentially result in no new interconnection. Either result would affect the long-term development plan currently recommended in the Power Resource Plan.

The proposed line in both Canada and the US will incur ongoing operation and maintenance costs, and the US portion will require annual management fees.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 2,627	$ 1,321	$ (1,306)
2013/14	$ 10,738	$ 444	$ (10,294)
2014/15	$ 11,769	$ 3,763	$ (8,006)
2015/16	$ 56,745	$ 29,706	$ (27,039)
2016/17+	$ 122,885	$ 315,112	$ 192,227
Total	$ 204,764	$ 350,346	$ 145,582

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The proposed In-Service Date is 2020, coincident with the start of the MP Sale.

Related Projects (This section is be filled out only if changed).

Reference Documents (This section is be filled out only if changed).

2012/13 Power Resource Plan.

Section:	Tab 4	Page No.:	4 of 26
Topic:	Capital Expenditures		
Subtopic:	New Generation & Transmission Project Costs.		
Issue:	Increases in Capital Expenditures		

PREAMBLE TO IR (IF ANY):

In addition to construction contract costs, Manitoba Hydro incurs other project related costs which are capitalized.

QUESTION:

In a similar format as PUB/MH I-10 (a) (2012 GRA) provide a table by major capital G&T project for the years 2008/09 to 2013/14 actual, listing the annual amounts incurred/paid to:

External Consultants hired by MH,
Internal MH Staff Costs,
MH funded expenses for costs incurred by third parties,
Amounts paid under joint generation development agreements, and
Annual mitigation costs paid to third parties.

RATIONALE FOR QUESTION:

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

RESPONSE:

The following table categorizes all capital spending for Major New Generation and Transmission projects from 2009 to 2014.

MAJOR NEW GENERATION & TRANSMISSION	**Fiscal Year**					
(In thousands)	**2,009**	**2,010**	**2,011**	**2,012**	**2,013**	**2,014**
Wuskwatim - Generation						
Internal MH Staff Costs	$ 13,134	$ 15,407	$ 15,597	$ 17,364	$ 12,935	$ 3,890
External Consultants hired by MH	11,337	12,517	8,014	2,527	1,735	870
MH Funded Expenses for Costs Incurred by Third Parties	121,554	245,111	218,395	90,103	36,654	6,837
Materials & Other	4,347	6,799	6,755	3,771	(5,511)	713
Joint Generation Development Agreements, Process and Study Costs*	869	1,248	1,278	1,228	2,062	210
Mitigation*	4,682	141	149	172	20	-
Capitalized Interest	18,717	28,347	44,779	58,642	23,825	54
	174,639	309,569	294,967	173,807	71,720	12,574
Wuskwatim - Transmission						
Internal MH Staff Costs	7,693	10,861	10,026	6,188	953	152
External Consultants hired by MH	23,708	15,633	3,474	3,866	1,117	1,494
MH Funded Expenses for Costs Incurred by Third Parties	33,000	16,352	1,683	2,189	21	6
Materials & Other	7,533	2,713	2,228	15,720	141	233
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	(618)	354
Mitigation*	126	270	360	487	-	-
Capitalized Interest	7,304	11,736	13,618	15,268	6,408	-
	79,366	57,564	31,388	43,718	8,022	2,239
Herblet Lake-The Pas 230 kV Transmission						
Internal MH Staff Costs	2,487	6,505	6,762	2,738	57	0
External Consultants hired by MH	3,757	2,156	651	786	181	242
MH Funded Expenses for Costs Incurred by Third Parties	1,916	13,765	8,231	240	2	-
Materials & Other	(1,528)	11,294	2,107	2,974	60	(1)
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	(133)	50
Mitigation*	-	-	-	-	-	-
Capitalized Interest	298	1,336	3,339	1,513	-	-
	6,931	35,055	21,090	8,251	167	291
Keeyask - Generation						
Internal MH Staff Costs	4,415	6,417	6,589	10,733	17,983	25,486
External Consultants hired by MH	11,803	11,731	2,340	2,330	16,936	26,800
MH Funded Expenses for Costs Incurred by Third Parties	42	135	5,149	17,745	54,452	161,955
Materials & Other	723	751	7,598	9,404	3,728	7,765
Joint Generation Development Agreements, Process and Study Costs*	12,579	12,388	8,051	8,783	8,177	8,082
Mitigation*	5,886	4,635	1,103	1,528	787	1,993
Capitalized Interest	18,832	20,620	25,605	29,707	35,715	45,316
	54,280	56,677	56,434	80,229	137,778	277,396
Grand Rapids Fish Hatchery Upgrade & Expansion						
Internal MH Staff Costs	-	-	-	-	-	286
External Consultants hired by MH	-	-	-	-	-	569
MH Funded Expenses for Costs Incurred by Third Parties	-	-	-	-	-	2
Materials & Other	-	-	-	-	-	9
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	-	-	-	-	34
	-	-	-	-	-	899

MAJOR NEW GENERATION & TRANSMISSION *(In thousands)*	**Fiscal Year** 2,009	2,010	2,011	2,012	2,013	2,014
Conawapa - Generation						
Internal MH Staff Costs	5,792	6,292	5,141	5,526	6,880	10,562
External Consultants hired by MH	12,591	6,674	5,238	2,869	4,551	7,176
MH Funded Expenses for Costs Incurred by Third Parties	670	1,313	628	59	352	2,263
Materials & Other	2,294	2,305	4,116	3,299	309	302
Joint Generation Development Agreements, Process and Study Costs*	3,961	3,699	2,414	2,431	3,146	3,477
Mitigation*	-	4,800	-	-	-	-
Capitalized Interest	8,120	10,087	12,188	14,019	15,496	16,716
	33,429	35,169	29,724	28,203	30,733	40,497
Kelsey Improvements & Upgrades						
Internal MH Staff Costs	9,093	7,945	8,648	8,051	7,276	5,434
External Consultants hired by MH	260	435	402	58	249	116
MH Funded Expenses for Costs Incurred by Third Parties	27,031	29,756	21,197	18,029	15,196	10,385
Materials & Other	5,479	6,105	4,378	3,607	3,579	2,694
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	2,614	2,788	3,172	3,049	1,512	904
	44,477	47,028	37,797	32,794	27,812	19,534
Kettle Improvements & Upgrades						
Internal MH Staff Costs	465	1,215	3,854	7,153	1,233	838
External Consultants hired by MH	3	15	256	24	26	19
MH Funded Expenses for Costs Incurred by Third Parties	10	6,045	11,013	10,023	1,463	780
Materials & Other	285	64	1,793	2,850	424	246
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	21	162	897	2,088	144	195
	785	7,502	17,814	22,137	3,289	2,078
Pointe du Bois - Spillway Replacement						
Internal MH Staff Costs	3,893	4,240	4,616	6,832	9,438	9,708
External Consultants hired by MH	7,438	4,049	6,885	8,767	7,002	7,380
MH Funded Expenses for Costs Incurred by Third Parties	189	(2)	505	3,673	64,573	201,027
Materials & Other	473	250	336	1,543	2,664	2,459
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	143	61
Mitigation*	-	-	-	-	-	6
Capitalized Interest	1,352	2,101	2,912	4,064	6,638	16,329
	13,346	10,639	15,253	24,880	90,456	236,969
Pointe du Bois - Transmission						
Internal MH Staff Costs	1,016	1,603	3,671	7,330	5,630	5,363
External Consultants hired by MH	296	452	824	(617)	71	681
MH Funded Expenses for Costs Incurred by Third Parties	81	18	1,350	1,426	1,115	4,248
Materials & Other	225	3,693	10,159	5,646	1,926	1,284
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	97	226	1,000	1,959	1,263	372
	1,715	5,992	17,004	15,743	10,004	11,947

MAJOR NEW GENERATION & TRANSMISSION	Fiscal Year					
(In thousands)	2,009	2,010	2,011	2,012	2,013	2,014
Gillam Redevelopment and Expansion Program						
Internal MH Staff Costs	-	-	12	(12)	-	-
External Consultants hired by MH	-	-	-	-	-	-
MH Funded Expenses for Costs Incurred by Third Parties	-	-	-	-	-	-
Materials & Other	-	-	2	(2)	-	-
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	-	-	-	-	-
	-	-	14	(14)	-	-
Bipole III - Transmission Line						
Internal MH Staff Costs	1,473	3,420	3,981	4,442	8,251	12,551
External Consultants hired by MH	916	3,932	5,266	4,819	2,486	2,259
MH Funded Expenses for Costs Incurred by Third Parties	2	3	40	1	2,894	17,159
Materials & Other	203	2,200	5,205	3,905	5,662	14,987
Joint Generation Development Agreements, Process and Study Costs*	-	247	2,374	1,786	1,291	1,732
Mitigation*	-	-	-	-	3	-
Capitalized Interest	744	1,907	2,135	3,398	4,505	5,588
	3,336	11,709	19,002	18,350	25,091	54,276
Bipole III - Converter Stations						
Internal MH Staff Costs	292	3,425	5,864	7,453	11,434	15,613
External Consultants hired by MH	531	3,151	3,708	5,551	6,395	6,656
MH Funded Expenses for Costs Incurred by Third Parties	-	1,877	5,163	13,848	39,228	96,823
Materials & Other	13,706	6,987	11,689	5,858	15,637	12,436
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	13	443	1,645	3,707	7,025	12,627
	14,542	15,882	28,069	36,417	79,718	144,153
Bipole III - Collector Lines						
Internal MH Staff Costs	-	-	318	985	1,672	3,752
External Consultants hired by MH	-	-	7	107	73	60
MH Funded Expenses for Costs Incurred by Third Parties	-	-	40	299	104	15,993
Materials & Other	-	-	20	620	2,341	5,878
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	-	2	64	204	582
	-	-	387	2,075	4,394	26,265
Bipole III - Community Development Initiative						
Internal MH Staff Costs	-	-	-	-	-	-
External Consultants hired by MH	-	-	-	-	-	-
MH Funded Expenses for Costs Incurred by Third Parties	-	-	-	-	-	-
Materials & Other	-	-	-	-	-	-
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	53,863
Capitalized Interest	-	-	-	-	-	-
	-	-	-	-	-	53,863

MAJOR NEW GENERATION & TRANSMISSION *(In thousands)*	Fiscal Year 2,009	2,010	2,011	2,012	2,013	2,014
Riel 230/500 kV Station						
Internal MH Staff Costs	2,189	3,798	4,635	5,472	7,669	12,356
External Consultants hired by MH	563	5,219	3,424	2,540	1,967	2,149
MH Funded Expenses for Costs Incurred by Third Parties	24	6,887	10,739	26,006	36,813	30,686
Materials & Other	663	8,684	24,383	12,471	27,648	13,891
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	220	895	3,284	6,244	10,040	14,428
Costs Transferred to Bipole 3 - Transmission	(1,651)	-	-	-	-	-
	2,007	25,483	46,465	52,732	84,136	73,510
Manitoba-Minnesota Transmission Project (formerly Dorsey - US Border New 500kV Transmission Line)						
Internal MH Staff Costs	-	-	64	2	108	1,205
External Consultants hired by MH	-	811	32	-	101	(113)
MH Funded Expenses for Costs Incurred by Third Parties	-	-	2	-	-	16
Materials & Other	-	-	5	1	3	60
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	-	56	65	72	(98)
	-	811	158	68	283	1,069
St. Joseph Wind Transmission						
Internal MH Staff Costs	6	462	3,529	704	23	4
External Consultants hired by MH	-	343	499	15	-	-
MH Funded Expenses for Costs Incurred by Third Parties	-	9	1,193	414	-	-
Materials & Other	-	(62)	2,777	(148)	30	-
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	4	134	51	14	-
	6	756	8,131	1,037	68	4
Firm Import Upgrades						
Internal MH Staff Costs	-	8	49	10	-	1
External Consultants hired by MH	-	-	109	-	-	1
MH Funded Expenses for Costs Incurred by Third Parties	-	-	-	-	-	-
Materials & Other	-	-	-	-	-	-
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	-	3	12	13	14
	-	8	161	22	13	15
Brandon Combustion Turbine Pipeline Upgrade						
Internal MH Staff Costs	-	-	-	-	-	-
External Consultants hired by MH	-	-	-	-	-	-
MH Funded Expenses for Costs Incurred by Third Parties	-	3,660	20	-	-	-
Materials & Other	-	-	-	-	-	-
Joint Generation Development Agreements, Process and Study Costs*	-	-	-	-	-	-
Mitigation*	-	-	-	-	-	-
Capitalized Interest	-	-	-	-	-	-
	-	3,660	20	-	-	-
Total	$ 428,857	$ 623,503	$ 623,878	$ 540,449	$ 573,682	$ 957,578

*Joint Generation Development Agreements, Process and Study Costs and Mitigation categories reflect both accruals and cash payments.

Section:	Tab 4	Page No.:	4 of 26
Topic:	Capital Expenditures		
Subtopic:	New Generation & Transmission Project Costs.		
Issue:	Increases in Capital Expenditures		

PREAMBLE TO IR (IF ANY):

In addition to construction contract costs, Manitoba Hydro incurs other project related costs which are capitalized.

QUESTION:

Please provide a similar analysis to (a) for the forecast period 2014/15 to 2023/24

RATIONALE FOR QUESTION:

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

RESPONSE:

Manitoba Hydro is unable to disclose the information as requested given concerns as to the sensitivity of disclosing future Joint Generation Development Agreements and Mitigation forecasts as many agreements are not yet finalized. Manitoba Hydro has provided the requested information to the PUB in confidence.

Section:	Tab 4	**Page No.:**	4 of 26
Topic:	Capital Expenditures		
Subtopic:	New Generation & Transmission Project Costs.		
Issue:	Increases in Capital Expenditures		

PREAMBLE TO IR (IF ANY):

In addition to construction contract costs, Manitoba Hydro incurs other project related costs which are capitalized.

QUESTION:

Please provide a similar level of breakdown in (a) and (b) for Sustaining Capital (Major & Base)

RATIONALE FOR QUESTION:

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

RESPONSE:

The following table categorizes all capital spending for Sustaining capital from 2009 to 2014 in a similar format as provided for Major and Major New Generation & Transmission projects in part a).

BUSINESS UNIT	Fiscal Year 2009	2010	2011	2012	2013	2014
Generation Operations						
Internal MH Staff Costs	$ 21,031	$ 25,390	$ 27,782	$ 32,505	$ 28,151	$ 33,467
External Consultants hired by MH	6,977	8,456	12,411	6,771	7,377	8,258
MH Funded Expenses for Costs Incurred by Third Parties	29,574	60,139	71,425	53,214	42,942	45,693
Materials & Other	8,858	10,246	16,781	20,475	15,507	20,072
Interest Capitalized	3,458	4,782	7,747	8,182	7,748	8,361
Joint Generation Development Agreements	-	-	-	300	721	49
	69,898	109,013	136,147	121,447	102,446	115,901
Transmission						
Internal MH Staff Costs	41,647	41,397	37,967	43,259	43,556	43,163
External Consultants hired by MH	3,763	4,936	5,686	6,616	7,019	8,605
MH Funded Expenses for Costs Incurred by Third Parties	11,081	9,880	20,161	8,917	13,086	10,875
Materials & Other	27,254	29,429	40,147	52,620	35,341	34,185
Interest Capitalized	3,560	4,486	4,511	5,891	6,526	6,004
	87,306	90,127	108,471	117,302	105,528	102,832
Customer Service & Distribution						
Internal MH Staff Costs	106,661	106,979	100,213	113,175	106,090	115,269
External Consultants hired by MH	847	764	1,277	217	1,015	2,156
MH Funded Expenses for Costs Incurred by Third Parties	15,100	13,529	11,043	21,388	25,844	28,229
Materials & Other	17,006	27,191	24,508	31,813	34,676	32,151
Interest Capitalized	3,298	3,998	4,172	5,865	7,630	7,942
	142,912	152,461	141,212	172,459	175,256	185,747
Customer Care & Energy Conservation						
Internal MH Staff Costs	31	132	199	169	383	512
External Consultants hired by MH	-	-	-	-	-	-
MH Funded Expenses for Costs Incurred by Third Parties	9	2	93	(34)	-	4
Materials & Other	2,308	2,495	2,782	2,825	2,306	2,515
Interest Capitalized	-	-	-	-	-	-
	2,348	2,629	3,074	2,961	2,689	3,031
Human Resources & Corporate Services						
Internal MH Staff Costs	9,920	10,762	11,909	12,117	12,215	12,002
External Consultants hired by MH	1,918	1,497	2,384	1,399	2,693	4,045
MH Funded Expenses for Costs Incurred by Third Parties	1,124	4,565	4,737	4,477	1,733	5,481
Materials & Other	32,557	33,253	33,278	31,824	28,928	39,557
Interest Capitalized	1,013	1,037	1,404	1,158	903	1,484
	46,533	51,113	53,711	50,975	46,471	62,570
Finance & Regulatory						
Internal MH Staff Costs	-	7	4	30	4	5
External Consultants hired by MH	-	-	-	0	0	0
MH Funded Expenses for Costs Incurred by Third Parties	-	-	-	5	-	-
Materials & Other	7	21	27	42	296	24
Interest Capitalized	-	-	-	-	-	-
	7	28	31	78	300	29
Total	**$ 349,005**	**$ 405,371**	**$ 442,646**	**$ 465,222**	**$ 432,690**	**$ 470,110**

With respect to part b), the forecast for Sustaining capital is based upon the establishment of annual targets which are allocated to each Business Unit considering financial and operational risks. The allocation of funds to individual projects is managed on an ongoing basis through the Business Units capital prioritization and approval processes. Detailed plans are developed as individual projects are identified and approved. As a result, the breakdown of the Sustaining capital forecast is not available at the same level of detail (i.e. by cost category) as individual project plans and actual spending.

However, Figure 4.12 in Tab 4 presents the Sustaining capital forecast by asset type for each Business Unit from 2015 to 2017 and was developed to supplement the Electric Infrastructure Condition Assessment report. The table below is an expansion of Figure 4.12 to include the remaining years, 2018 to 2024. The seven year projection was 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	2018-2024	10 Year Total
Generation Operation					
Turbines	$ 19.7	$ 13.4	$ 15.8	$ 117.7	$ 166.5
Generators	14.4	17.8	20.1	201.6	254.0
Auxiliary Systems (Sewer, Water, Fire, etc)	12.4	10.3	12.5	29.2	64.4
Transformers	12.4	7.4	7.9	120.8	148.4
Licensing	10.4	10.8	8.3	44.0	73.6
Instrumentation & Controls	9.0	15.1	11.8	33.0	68.8
Townsite Infrastructure	8.9	10.4	5.0	16.7	41.1
Breakers	8.9	4.3	1.3	57.7	72.3
Spillway & Water Controls	7.4	13.5	24.1	62.0	107.0
Powerhouse, Dams, Dykes	6.7	7.6	8.1	41.4	63.7
Physical Security & Public Safety	5.4	3.2	2.0	13.0	23.5
AC Supporting Electrical Systems	5.2	7.6	6.4	67.5	86.7
Governors	4.6	3.9	1.6	27.4	37.6
Exciters	2.9	3.5	3.7	41.7	51.7
Tools & Equipment	2.4	2.2	1.4	7.7	13.7
Communication Systems & Equipment	1.4	1.2	1.9	7.4	11.9
Combustion Turbines	-	-	-	51.4	51.4
	132.0	**132.0**	**132.0**	**940.1**	**1,336.1**
Transmission					
Station Equipment	16.3	15.2	13.9	140.7	186.1
Station Civil Infrastructure	15.9	9.1	2.8	83.2	110.9
Transformers	15.2	12.5	12.6	49.6	89.9
Communication Systems & Equipment	14.5	7.2	8.6	71.6	101.9
Protection Relays & Control, Metering & SCADA	13.8	7.2	3.2	11.9	36.1
HVDC Synchronous Condensers	9.0	8.8	2.9	20.7	41.4
Steel Structures	7.3	12.4	34.0	126.0	179.6
Wood Poles	6.7	33.2	14.1	45.7	99.7
Breakers	6.7	5.3	3.7	34.8	50.6
Battery Banks	4.0	2.5	1.9	13.4	21.9
Conductor Attachments	3.6	4.4	5.1	5.4	18.4
HVDC Valve Group	2.8	0.7	0.1	246.6	250.2
Tools & Equipment	2.4	1.6	1.4	30.0	35.4
Land & Easements	2.3	1.1	10.2	16.6	30.2
Overhead Conductors	1.8	2.4	9.5	50.1	63.8
System Control Centre	0.4	0.3	0.3	5.4	6.3
Diesel Generation	0.4	-	-	23.1	23.5
HVDC Smoothing Reactors	0.1	0.4	0.5	-	1.0
Other	1.8	0.9	0.1	0.2	3.1
	125.0	**125.0**	**125.0**	**975.0**	**1,350.0**
Customer Services & Distribution					
Poles	43.3	38.5	48.3	302.9	433.0
Overhead Conductors	39.1	33.3	33.8	179.2	285.4
Underground Cables	31.3	37.3	45.5	260.9	375.1
Station Breakers and Other Station Equipment	23.8	29.6	28.7	146.2	228.3
Overhead Transformers	22.5	18.2	22.2	112.6	175.5
Station Transformers	21.0	23.1	24.7	120.7	189.5
Padmount Transformers	17.9	12.2	15.7	77.3	123.1
Street Lights	11.0	10.8	12.8	68.7	103.4
Ductlines & Manholes	7.9	16.0	13.2	85.2	122.4
Station Site Prep	6.0	9.2	9.3	45.0	69.4
Land & Easement	3.7	0.4	0.0	0.0	4.1
Buildings	4.4	10.1	12.7	61.4	88.5
Equipment	1.4	1.2	1.4	7.0	11.0
Steel Structures	0.8	0.7	-	-	1.6
Other	1.3	-	-	-	1.3
	235.5	**240.9**	**268.3**	**1,467.1**	**2,211.8**
Customer Care & Energy Conservation					
Meters & Meter Transformers	3.2	4.0	4.1	28.0	39.2
	3.2	**4.0**	**4.1**	**28.0**	**39.2**
Human Resources & Corporate Services					
Computers & IT Systems	29.0	29.1	29.6	201.1	288.9
Buildings	22.4	24.3	9.3	70.2	126.2
Fleet	21.0	18.9	13.3	98.7	152.0
Land & Easements	1.7	1.8	1.8	14.3	19.6
Tools & Equipment	0.9	0.9	0.9	7.3	10.0
	75.0	**75.0**	**55.0**	**391.7**	**596.7**
Finance Regulatory					
Tools & Equipment	0.2	0.2	0.2	1.6	2.2
	0.2	**0.2**	**0.2**	**1.6**	**2.2**
Target Adjustment	-	-	25.0	100.0	125.0
Sustaining Capital Total	**$ 570.9**	**$ 577.0**	**$ 609.6**	**$ 3,903.4**	**$ 5,661.0**

Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	**Page No.:**	14
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please detail all expenditures related to Conawapa from 2014 to 2017.

RATIONALE FOR QUESTION:

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

RESPONSE:

Please see the response to PUB/MH-I-23c.

Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	**Page No.:**	14
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

In (a), please detail any monies paid, including payments to First Nations, consultants, and contractors relating to the cancellation of any agreements related to Conawapa.

RATIONALE FOR QUESTION:

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

RESPONSE:

As of December 31, 2014, a total of $195,700 has been paid to First Nations as a result of the cancellation of agreement related to Conawapa. There have been no monies paid to consultants or contractors as a result of the cancellation of agreements related to Conawapa.

Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	**Page No.:**	14
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the cumulative detail of the $397 million balance of Conawapa expenditures by major category in similar level of detail of the response to PUB/MH I-10 (a) (2012 GRA).

RATIONALE FOR QUESTION:

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

RESPONSE:

Please see the following schedule which outlines the Conawapa expenditures by major category from 2004 to 2017.

CONAWAPA GS							**Fiscal Year**						
In thousands	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015-2017**	**Total**
Conawapa - Generation													
Internal MH Staff Costs	$ 49	$ 2 503	$ 4 790	$ 6 762	$ 6 338	$ 5 792	6 292	5 141	5 526	6 880	10 562	-	60 636
External Consultants hired by MH	148	4 096	8 167	12 585	11 748	12 591	6 674	5 238	2 869	4 551	7 176	-	75 842
MH Funded Expenses for Costs Incurred by Third Parties	-	26	415	3 107	1 540	670	1 313	628	59	352	2 263	-	10 371
Materials & Other	-	1 563	13 992	5 239	4 707	2 294	2 305	4 116	3 299	309	302	-	38 125
Joint Generation Development Agreements, Process and Study Costs	-	291	734	1 510	3 958	3 961	3 699	2 414	2 431	3 146	3 477	-	25 621
Mitigation	-	-	-	-	-	-	4 800	-	-	-	-	-	4 800
Capitalized Interest	-	(1)	-	3 434	5 740	8 120	10 087	12 187	14 019	15 496	16 716	-	85 798
Forecast Years:													
Pre-Suspension Activities	-	-	-	-	-	-	-	-	-	-	-		10 952
Negotiations and environmental assessments												5 306	
NFAT												2 872	
Engineering												2 206	
Regional Cumulative Effects assessment												293	
Public engagement programs												102	
Other												173	
Post-Suspension Activities	-	-	-	-	-	-	-	-	-	-	-		22 370
Aboriginal Traditional Studies												7 500	
Environmental Studies												9 600	
Close of negotiations and environmental assessment activities, regulatory activities and engineering												2 370	
Contingency & project management												2 900	
Capitalized Interest and Escalation	-	-	-	-	-	-	-	-	-	-	-	62 469	62 469
	197	8 478	28 098	32 636	34 030	33 429	35 169	29 724	28 203	30 733	40 496	95 791	$ 396 984

Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	**Page No.:**	14
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain the proposed regulatory accounting treatment for the $397 million spent on Conawapa to be put into service in 2017 and the rationale for this treatment.

RATIONALE FOR QUESTION:

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

RESPONSE:

IFF14 was prepared based on an assumption that the activities described in the response to MIPUG/MH-I-10a would be concluded by 2016/17 and after that time, Manitoba Hydro would not proceed with any further activities associated with the Conawapa Generating Station. As such, for the completeness of the forecast, it was assumed in IFF14 that the deferred Conawapa costs would be treated as a regulatory deferral account balance and amortized over a period of 30 years commencing in 2016/17. A 30-year amortization period was assumed in order to minimize the potential impact on rates and promote rate stability for customers.

Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	**Page No.:**	14
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule detailing the proposed full amortization of Conawapa costs.

RATIONALE FOR QUESTION:

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

RESPONSE:

This information is contained in Appendix 11.15 Financial Information MFR 9.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Keeyask Generating Station Project Cost		
Issue:	Revised Cost Estimates		

PREAMBLE TO IR (IF ANY):

The latest Keeyask Generating Station project cost estimate in CEF 14 is $6.496B, the same as reported during NFAT. MH has since awarded contracts for a major portion of the work to be done on Keeyask.

QUESTION:

Provide an updated breakdown of each awarded contract document and pending contract documents.

RATIONALE FOR QUESTION:

Capital costs for new generation are one of the reasons for Manitoba Hydro's rate increase requests.

RESPONSE:

Approximately 90% of contracts have been awarded as of December 31, 2014 for a total value to date of $2.74 B. The total value of awarded contracts as of December 31, 2014 is within the overall control budget.

A further break-down of contract values is commercially sensitive as several major contracts are still to be awarded and providing such a breakdown could provide bidders with information on amounts remaining in the budgets for the remainder of the contracts.

Information on awarded contracts is as follows:

- Approximately 96% (by $ value) of Civil Contracts for Direct Work on the Generating Station have been awarded.
- Approximately 80% (by $ value) of Mechanical and Electrical Contracts for Direct Work on the Generating Station have been awarded.
- Approximately 85% (by $value) of other contracts for Indirect Work, and Transmission Work on the Keeyask Project, have been awarded.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Keeyask Generating Station Project Cost		
Issue:	Revised Cost Estimates		

PREAMBLE TO IR (IF ANY):

The latest Keeyask Generating Station project cost estimate in CEF 14 is $6.496B, the same as reported during NFAT. MH has since awarded contracts for a major portion of the work to be done on Keeyask.

QUESTION:

Provide the CPJ sheets for the last two years that would support the current estimate.

RATIONALE FOR QUESTION:

Capital costs for new generation are one of the reasons for Manitoba Hydro's rate increase requests.

RESPONSE:

Please find attached the capital project justification supporting the current estimate for Keeyask

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

Keeyask Generating Station

Addendum #4

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: Dave Bo

Constructing Division: Dave B

Financial Department: Doreen Perez
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: Ant... OCT. 28, 2014

Business Unit V.P.: Bruce A Barrett 31 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$6,220,088,000
REVISED BUDGET $: (Total Net Cost)	$6,496,061,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 12
REVISED ISD: (Last Major In-service Date)	2020 12
RISK MATRIX/ BUSINESS CASE TIER:	n/a
INVESTMENT REASON:	CL04 Future Power Generation

OWNING DIVISION: New Generation Construction

I.M. NODE NUMBER: 1.5.1.6

W.B.S. NUMBERs: P:05866/P:14539/P:14621/P:14622/ P:15264/P:15955/P:16020/P:16021/ P:16022/P:16024/P:16895/P:18568/ P:14625/P:14703/P:16892/P:16897/ P:17448/P:21087/P:21089

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J.D. Bowen

DATE PREPARED: 2014 10 21

REPORT NUMBER:

FILE NUMBER (Optional):

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
4	2014 03 20	Revision to budget	J.D. Bowen	
3	2012 09 06	Sensitivity Analysis Review	G.P.F. Schick	E.C. Minute 1418.04
2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	CPJ	C. Michaluk	Board Minute # 796-08 04

Project Name (This section is required for all Addendums).
Keeyask Generating Station

Recommendation (This section is required for all Addendums).
That the project estimate be increased by $276 million to a revised total of $6,496 million.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change

Background (This section is be filled out only if there is information relevant to the recommendation).

This CPJA reflects the control budget prepared as part of the NFAT and a detailed summary is provided below.

The Keeyask Project control budget was updated in March 2014. The last detailed project estimate was completed in 2009 with a detailed sensitivity analysis conducted in Summer of 2012. The control budget includes bid prices from the major contractors including the General Civil Contract and current budget of the Keeyask Infrastructure Project.

<u>P50 Estimate:</u>
The following changes were made to the P50 Estimate:

- Increase for actual escalation to bring the estimate to 2014$ with a subsequent decrease to future escalation resulting in no net change
- Increase for the difference between awarded value and estimate for the General Civil Works, plus the addition of a performance bonus
- Increase for post-construction adverse effects due to signed agreement
- Increase for site staffing due to partial augmentation through an external consultant
- Decrease to contingency based on an updated risk model

<u>Reserves:</u>
The following changes were made to the Management Reserves:

- Decrease to the labour & escalation reserves as a result of re-calculation using current information from the General Civil Contract

<u>In-Service Costs:</u>
The overall increase to the in-service cost of the project is $276M (5%). The increase to the in-service cost is due to increases to the P50 estimate and corresponding increase to interest offset by a decrease to management reserves and escalation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
No change.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The Labour and Escalation risks previously identified remain unchanged; however the reserve amounts have been re-calculated.

Labour:
The Labour Reserve was re-calculated using the methodology followed in 2012 but with new information as a result of awarding the General Civil Contract. Both the successful and the highest bidder, in combination with lessons learned, including the Wuskwatim project, were used as a basis of deriving the new reserve with an additional consideration of the successful bidder's contracting strategy.

Escalation:
The Escalation Reserve was re-calculated using the revised total project capital costs and associated cashflows.

Interest:
Interest has the potential to change the control budget significantly. Recent updates to interest may cause an increase to the control budget and in-service costs. This will be continuously evaluated over the life of the project.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No change.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 502,072	$ 502,072	$ -
2012/13	$ 201,778	$ 137,778	$ (64,001)
2013/14	$ 339,036	$ 277,396	$ (61,640)
2014/15	$ 405,137	$ 776,272	$ 371,135
2015/16	$ 636,463	$ 676,333	$ 39,870
2016/17	$ 883,863	$ 962,189	$ 78,326
2017/18	$ 1,132,127	$ 1,351,297	$ 219,170
2018/19	$ 955,395	$ 927,908	$ (27,487)
2019/20	$ 804,135	$ 616,472	$ (187,663)
2020/21	$ 288,155	$ 208,578	$ (79,577)
2021/22	$ 71,926	$ 55,193	$ (16,733)
2022/23	$ -	$ 4,470	$ 4,470
2023/24	$ -	$ 103	$ 103
Total	$ 6,220,088	$ 6,496,061	$ 275,973

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

2014 Public Utilities Board Report on the Needs for and Alternatives To
K-C NFAT Submission – Original NFAT submission
March 2014 Update - Presentation & Undertakings
2013/14 Power Resource Plan
CPJ dated October 15, 2008 - Keeyask Generating Station
CPJ Addendum #1 dated March 6, 2009
CPJ Addendum #2 dated September 09, 2010
CPJ Addendum #3 dated September 6, 2012

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1418.04

DATE: 2012 10 30
Financial Planning

CAPITAL PROJECT JUSTIFICA FOR

Keeyask Generating Station

Addendum #3

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$5,636,949,000
REVISED BUDGET $: (Total Net Cost)	$6,220,088,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 08
REVISED ISD: (Last Major In-service Date)	2020 12
RISK MATRIX/ BUSINESS CASE TIER:	n/a
INVESTMENT REASON:	CL04 Future Power Generation

OWNING DIVISION: New Generation Construction

I.M. NODE NUMBER: 1.5.1.6

W.B.S. NUMBERs: P:05866/P:14539/P:14621/ P:14622/P:15264/P:15955/P:16021/ P:16022/P:16895/P:18568/P:14625/ P:14703/P:16892/P:16897/P:17448

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: G.P.F Schick

DATE PREPARED: 2012 09 06

REPORT NUMBER:

FILE NUMBER (Optional):

2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	CPJ	C. Michaluk	Board Minute # 796-08 04
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Keeyask Generating Station

Recommendation (This section is required for all Addendums).
That the project estimate be increased by $583 million to a revised total of $6,220 million.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change

Background (This section is be filled out only if there is information relevant to the recommendation).

The last detailed project estimate was completed in 2009 with a detailed sensitivity analysis conducted in the Summer of 2012. This review incorporated up-to-date experiences and recent market information. The results of the review showed the need to adjust estimate to better address uncertainty related to future costs. As such, the recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for labour and escalation risks.

P50 Estimate:

Since the last estimate was developed in 2009 it was necessary to bring the estimate to 2012$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in the following changes to the P50 Estimate:

- $187M increase for actual escalation that has occurred to bring the estimate to 2012$.
- $34M increase to Planning & Licensing for additional adverse affects, regulatory and environmental costs related to Sturgeon activities, First Nation Activities and EIS preparation
- $60M increase toTransmission costs due to increased detail of scope to include tower type and numbers, additional lines from GS to Switching Stn, additional bank addition and breaker replacments
- $17M increase to infrastructure costs to upgrade camp for labour attraction and retention

Reserves:

A Management Reserve has been established to address significant risks related to labour ($384M) & escalation ($116M). See Risk Analysis section.

In-Service Costs:

The overall increase to the in-service cost of the project is $583M (10%). This increase to the in-service cost is due to the addition of the Management Reserve and base estimate increases offset by reduced interest costs from reduced forecasted interest rates ($215M).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
An additional dependable energy source is required in 2019/20 to meet forecast Manitoba loads and export commitments consistent with the recommended development plan of the 2012/13 Power Resource Plan.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Keeyask risks related to labour productivity & escalation are addressed through use of management reserves due to the magnitude of the cost variation they may cause. Keeyask estimates include both a labour reserve and an escalation reserve:

The labour reserve represents the potential additional costs associated with labour productivity and cumulative impacts. The labour reserve is derived by applying outcomes of the Wuskwatim process reviews to the labour components of the Keeyask estimates including:

- Increases to the number of labour hours required per work activity and the resulting number of workers due to reduced labour productivity;
- Additional costs for extended construction duration due to lower productivity;
- Increases to collective agreement wages to attract and retain workers; Increases to the size of the camp to accommodate the additional workers required due to lower productivity;
- Increases to the service contracts to accommodate the additional workers required;
- Increases to project management costs related to additional supervisory staff to monitor less experienced and less productive workers; and
- Additional costs for 7-12 work schedule (7 days per week, 12 hours per day).

The Corporation expects to utilize the labour reserve if there are restrictions in our ability to address the current and expected state of the Canadian construction labour market (demand/supply), specifically labour availability and productivity. Examples include (a) restrictions on the ability to modify wage rates, hours

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

of work per day, and turnaround schedules in the Burntwood Nelson Agreement, and (b) constraints on the project using labour outside of Manitoba and Canada.

The escalation reserve represents the potential additional costs to the project associated with cost escalation greater than Canadian CPI. The escalation reserve is derived by projecting the total project capital costs utilizing rates of inflation comprised of components directly related to major hydro project construction, such as copper, cement, concrete reinforcing bar, and diesel fuel price increases, rather than the broadly defined components comprising Canadian CPI. The Corporation expects that it will utilize the escalation reserve.

Considering the uncertainties in heavy construction escalation, labour productivity and project construction conditions, there is a greater likelihood that the actual costs to construct Keeyask will be less than the updated cost estimates than more. This is provided that the in-service dates, interest rates, escalation and major scope items are consistent with the estimate assumptions.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No changes to the resource requirements.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$365,409	$365,409	$0
2010/11	$71,140	$56,434	($14,706)
2011/12	$152,465	$80,229	($72,236)
2012/13	$179,137	$201,778	$22,641
2013/14	$316,097	$339,036	$22,939
2014/15	$381,566	$405,137	$23,571
2015/16	$684,346	$636,463	($47,883)
2016/17	$750,677	$883,863	$133,186
2017/18	$1,082,934	$1,132,127	$49,193
2018/19	$813,264	$955,395	$142,131
2019/20	$631,995	$804,135	$172,140
2020/21	$207,919	$288,155	$80,236
2021/22		$71,926	$71,926
Total	$5,636,949	$6,220,088	$583,139

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).
The PR 280 Upgrades started in October 2010 as outlined in CPJA#2 The Infrastructure started in December 2011 which is 6 months later than the date outline in CPJA#2 The first unit In-Service-Date is November of 2019 (unchanged from CPJA#2) and the last unit In-Service Date is December of 2020 (4 months later than CPJA#2).

Related Projects (This section is be filled out only if changed).
Conawapa Generating Station Transmission Lines related to Export Sales to Minnesota Power and Wisconsin Public Service Bipole III Transmission and Converters

Reference Documents (This section is be filled out only if changed).
2012 Keeyask & Conawapa Recommended Budgets 2012 Keeyask & Conawapa Sensitivity Analysis Summary 2012 EC Recommendation – Keeyask Budget Basis - August 28, 2012 Minute 1409.02 2012 Power Resource Plan Report

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Keeyask Generating Station Project Cost		
Issue:	Revised Cost Estimates		

PREAMBLE TO IR (IF ANY):

The latest Keeyask Generating Station project cost estimate in CEF 14 is $6.496B, the same as reported during NFAT. MH has since awarded contracts for a major portion of the work to be done on Keeyask.

QUESTION:

Provide an update on contingency and management reserves.

RATIONALE FOR QUESTION:

Capital costs for new generation are one of the reasons for Manitoba Hydro's rate increase requests.

RESPONSE:

Overall, total planned project costs are within the total control budget and there are no significant changes to the planned project contingency drawdown and management reserves to report at this time. Manitoba Hydro will continue to monitor the forecast to completion (or outlook) for the project control budget.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Keeyask Generating Station Project Cost		
Issue:	Revised Cost Estimates		

PREAMBLE TO IR (IF ANY):

The latest Keeyask Generating Station project cost estimate in CEF 14 is $6.496B, the same as reported during NFAT. MH has since awarded contracts for a major portion of the work to be done on Keeyask.

QUESTION:

Provide a cost summary of mitigation obligations.

RATIONALE FOR QUESTION:

Capital costs for new generation are one of the reasons for Manitoba Hydro's rate increase requests.

RESPONSE:

The estimate for mitigation obligations is $209M as of December 31, 2014.

The estimate includes the following:

- Environmental Mitigation
- Social Mitigation
- Adverse Effects Payment Obligation
- Operational Employment Payment Obligation

Section:	Tab 4:	**Page No.:**	
Topic:	Capital Expenditure Forecast		
Subtopic:	Projects in excess of $5 million		
Issue:	Changes in CEF		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a list of all projects over the 2012/13 to 2023/24 period where the total project costs have changed as between CEF11-2 and CEF14 and the current total project cost exceeds $5M. Where the difference is more than 5% please provide an explanation.

RATIONALE FOR QUESTION:

To understand the changes in capital expenditure costs of major projects.

RESPONSE:

The table below provides a list of all projects over the 2012/13 to 2023/24 period where the total project costs have changed from CEF12 to CEF14 and the current total project cost exceeds $5M. Where the difference is greater than 5% an explanation is provided below the table.

Projects *(in millions of dollars)*	CEF12 Total Cost	CEF14 Total Cost	Increase/ (Decrease) in CEF	Percentage Increase/ (Decrease)	Reference
Conawapa - Generation	10,192.4	397.0	(9,795.4)	-96%	1
Kelsey Improvements & Upgrades	301.7	340.4	38.6	13%	2
Kettle Improvements & Upgrades	165.7	191.6	25.9	16%	3
Pointe du Bois - Transmission	85.9	114.3	28.4	33%	4
Pointe du Bois Powerhouse Rebuild	1,538.3	1,852.2	313.9	20%	5
Gillam Redevelopment and Expansion Program (GREP)	366.5	266.5	(100.0)	-27%	6
Riel 230/500kV Station	267.6	329.9	62.4	23%	7
Manitoba-Minnesota Transmission Project	204.8	350.3	145.6	71%	8
Generating Station Improvements & Upgrades	98.3	138.6	40.3	41%	9
Great Falls Unit 4 Overhaul	43.2	53.6	10.5	24%	10
New Madison Station - 115/24kV Station	65.9	87.1	21.2	32%	11
Burrows New 66/12kV Station	42.6	54.7	12.1	28%	12
Bipole III - Transmission Line	1,259.9	1,655.4	395.5	31%	13
Bipole III - Converter Stations	1,828.5	2,675.1	846.6	46%	13
Bipole III - Collector Lines	191.4	260.2	68.7	36%	13

1. Conawapa – Generation: The decrease reflects suspension of construction activities pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in process through August 2016.

2. Kelsey Improvements & Upgrades: The increase is primarily related to deficiency work on the head covers of all seven units required to improve safety and reliability. In addition, increased costs for wastewater treatment upgrades.

3. Kettle Improvements & Upgrades: The increase reflects actual costs incurred for Unit 4 including scope increases for thrust runner replacements, new excitation transformer, rebabitting of bearings and the removal and disposal of the old stator for units 1-4.

4. Pointe du Bois – Transmission: The increase is primarily related to a change in concept for replacement of the 66kV lines from Pointe du Bois to Rover Stations as well as increased costs for the Stafford Stations rebuild and Pointe du Bois Bank 7 replacement.

5. Pointe du Bois Powerhouse Rebuild: The increase is primarily to reflect revised interest and escalation costs as a result of the deferral of the in-service date to 2039/40.

6. Gillam Redevelopment and Expansion Program (GREP): The decrease reflects a re-evaluation of the project resulting in cost reductions due to optimization of the project through a re-design of the town centre, residential site development, trailer park and industrial park as well as a re-analysis of customer requirements resulting in a reduction in the scope of work.

7. Riel 230/500kV Station: The increase is primarily related to incorporation of awarded contracts amounts and a deferral of the in-service date from May 2014 to October 2014.

8. Manitoba-Minnesota Transmission Project: The increase reflects additional line length and a scope increase for a phase shifting transformer and the associated transmission line re-alignment at Glenboro Station.

9. Generating Station Improvements & Upgrades: The increase reflects an increased provision for overhauls at northern generating stations.

10. Great Falls Unit 4 Overhaul: The increase reflects additional work to refurbish the service bay floor, upgrade line protection as a result of an Interconnection Study, upgrade the powerhouse crane, repair a damaged draft tube elbow as well as increased interest costs associated with a delay in in-service.

11. New Madison Station – 115/24kV Station: The increase reflects scope changes requiring installation of new cable, re-design of the 115kV terminations, addition of special bus bar connections, modification of the existing switchgear, relocations of circuits, and protection upgrades. In addition, awarded contract prices and updated interest and escalation were included.

12. Burrows New 66/12kV Station: The increase reflects a deferral of the project in-service date from March 2013 to March 2015 as well as increased costs to complete the feeder conversions and to install a new 66kV underground supply.

13. Bipole III: Please refer to PUB/MH-I-20a for an explanation of the increase in costs.

Section:	Tab 4:	**Page No.:**	
Topic:	Capital Expenditure Forecast		
Subtopic:	Projects in excess of $5 million		
Issue:	Changes in CEF		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule setting out all capital projects that were placed in- service in 2012/13 to 2031/14 (or 2014/15 if available) with a total cost of more than $5M. Compare the estimated project costs as per IFF11-2 with the total final costs. Please provide an explanation for any variances greater than 5%.

RATIONALE FOR QUESTION:

To understand the changes in capital expenditure costs of major projects.

RESPONSE:

The table below provides a list of all projects that were placed in-service in 2012/13 or 2013/14 with a total cost of greater than $5 million and a variance of greater than $1 million.

Projects (in millions of dollars)	CEF12 Forecast	In-Service Cost	Under/(Over) Expenditure	Reference
Wuskwatim - Transmission	322.9	320.0	2.9	1
Seven Sisters Rewind	10.5	14.6	(4.1)	2
Transmission Line Re-rating	31.7	30.4	1.3	3
Dorsey 230KV Relay Bldg - Phase 1	17.4	12.6	4.8	4
HVDC Converter Transformer Bushing Replacement	5.9	4.1	1.8	5
Winpak 5 Year - 7MVA Expansion	9.4	7.8	1.6	6
Frobisher Station Upgrade	14.4	12.9	1.5	7
York Station Bank & Switchgear Addition	6.0	7.7	(1.6)	8
Defective RINJ Cable Replacment	8.7	6.4	2.3	9

1. Wuskwatim Transmission: The under expenditure was primarily due to the project not requiring the risk forecast associated with schedule, contractor or material delays, price fluctuations, and additional unforeseen costs.

2. Seven Sisters Rewind: The over expenditure was primarily due to issues identified during the disassembly of the unit.

3. Transmission Line Re-rating: The under expenditure is due to a lower requirement for transmission line design activities than originally planned for data analysis and identification of line clearance violations.

4. Dorsey 230kV Relay Bldg – Phase I: The under expenditure reflects cancellation of work to design and purchase three mobile protection and control trailers no longer required as a result of the hardening and fire risk mitigation of the Dorsey 230kV Relay Building and the addition of Bipole III.

5. HVDC Converter Transformer Bushing Replacement: The under expenditure is due a scope change to removing the replacement of the 450kV bushings from the project.

6. Winpak 5 Year 0 7MVA Expansion: The under expenditure is primarily due to a shorter distribution line route reducing overall costs.

7. Frobisher Station Upgrade: The under expenditure is due to less work required for the feeder upgrade than anticipated.

8. York Station Bank & Switchgear Addition: The over expenditure was due to the failure in acceptance testing for several switchgear which resulted in a delay in delivery, design, construction and commissioning activities.

9. Defective R1NJ Cable Replacement: The under expenditure was primarily due to a change in scope to only replace defective cables.

Section:	Tab 5: Section 5.6 Figure 5.8 Appendix 11.38	**Page No.:**	22
Topic:	Financial Results and Forecasts		
Subtopic:	Finance Expense		
Issue:	Finance Expense and Interest Allocated to Construction		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please recast Figure 5.8 to include the provincial debt guarantee fee and extend the graph to 2034.

b) Please confirm Figure 5.8 represents the information in Appendix 11.38. If not please file the data underlying Figure 5.8.

c) Please include on Figure 5.8 the comparative plot of finance expense based on IFF13.

RATIONALE FOR QUESTION:

To understand the changes in detail of finance expense from the last forecast.

RESPONSE:

a) Numerical values supporting the finance expense information depicted in Figure 5.8 were filed in Appendix 11.38 with the exception of the data for the fiscal year 2008/09. A revised table from Appendix 11.38 is supplied in this response to provide for completeness of data.

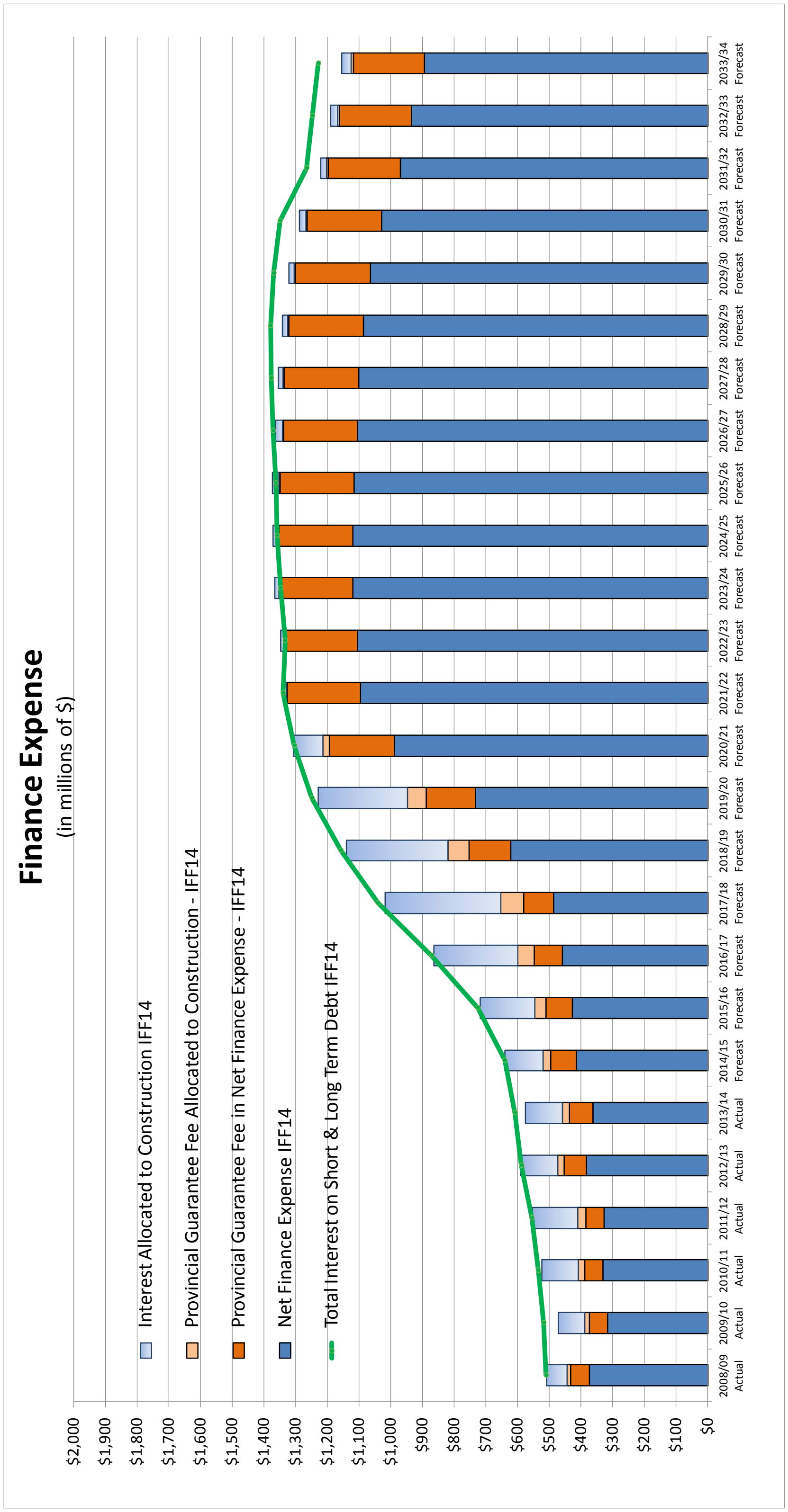
MANITOBA HYDRO
Summary of Total Finance Expense IFF14
($ millions CAD)

	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	$ 469	$ 472	$ 472	$ 490	$ 515	$ 528	$ 554	$ 627	$ 756	$ 903	$ 995	$ 1,076	$ 1,120
Provincial Guarantee Fee	70	72	77	82	90	96	105	118	140	167	197	213	225
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)	(23)	(27)	(32)	(37)	(42)	(45)
Total Interest on Short & Long Term Debt	**509**	**517**	**535**	**555**	**587**	**608**	**640**	**725**	**871**	**1,040**	**1,157**	**1,248**	**1,303**
Interest Allocated to Construction	**(74)**	**(98)**	**(136)**	**(167)**	**(138)**	**(140)**	**(146)**	**(207)**	**(316)**	**(437)**	**(388)**	**(341)**	**(112)**
Interest Earned on Sinking Fund	(25)	(24)	(17)	(10)	(10)	(24)	(0)	(2)	(9)	(19)	(24)	(24)	(21)
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**	**$ 510**	**$ 548**	**$ 581**	**$ 752**	**$ 887**	**$ 1,194**

	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	$ 1,137	$ 1,125	$ 1,141	$ 1,149	$ 1,154	$ 1,163	$ 1,168	$ 1,171	$ 1,161	$ 1,143	$ 1,067	$ 1,050	$ 1,032
Provincial Guarantee Fee	232	231	233	236	236	238	239	240	241	239	232	232	232
Amortization of (Premiums), Discounts, and Transaction Costs	4	3	1	2	2	2	2	3	3	3	4	4	4
Intercompany Interest Receivable	(34)	(26)	(28)	(29)	(30)	(32)	(33)	(34)	(36)	(37)	(39)	(39)	(40)
Total Interest on Short & Long Term Debt	**1,338**	**1,333**	**1,347**	**1,358**	**1,362**	**1,371**	**1,376**	**1,379**	**1,368**	**1,349**	**1,264**	**1,247**	**1,228**
Interest Allocated to Construction	**(12)**	**(14)**	**(17)**	**(20)**	**(24)**	**(25)**	**(17)**	**(20)**	**(20)**	**(24)**	**(25)**	**(27)**	**(38)**
Interest Earned on Sinking Fund	(19)	(7)	(9)	(13)	(16)	(30)	(44)	(59)	(69)	(82)	(62)	(76)	(91)
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	**$ 1,326**	**$ 1,334**	**$ 1,349**	**$ 1,351**	**$ 1,348**	**$ 1,338**	**$ 1,337**	**$ 1,321**	**$ 1,301**	**$ 1,263**	**$ 1,197**	**$ 1,161**	**$ 1,116**

b) On the following page, the original Figure 5.8 in Tab 5 has been extended to 2033/34 and has been recast to separately identify the provincial debt guarantee fee. In the original Figure 5.8, a portion of the provincial debt guarantee fee would have been included within the total interest allocated to construction, with the residual amount of provincial debt guarantee fee included in net finance expense.

The proportion of interest allocated to construction divided by gross interest for any fiscal year was used to calculate the amount of provincial debt guarantee fee allocated to construction for that fiscal year, with the residual amount of provincial debt guarantee fee included in net finance expense.


Finance Expense
(in millions of $)
Interest Allocated to Construction IFF14
Provincial Guarantee Fee Allocated to Construction - IFF14
Provincial Guarantee Fee in Net Finance Expense - IFF14
Net Finance Expense IFF14
Total Interest on Short & Long Term Debt IFF14
$2,000
$1,900
$1,800
$1,700
$1,600
$1,500
$1,400
$1,300
$1,200
$1,100
$1,000
$900
$800
$700
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$500
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2008/09 Actual
2009/10 Actual
2010/11 Actual
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2015/16 Forecast
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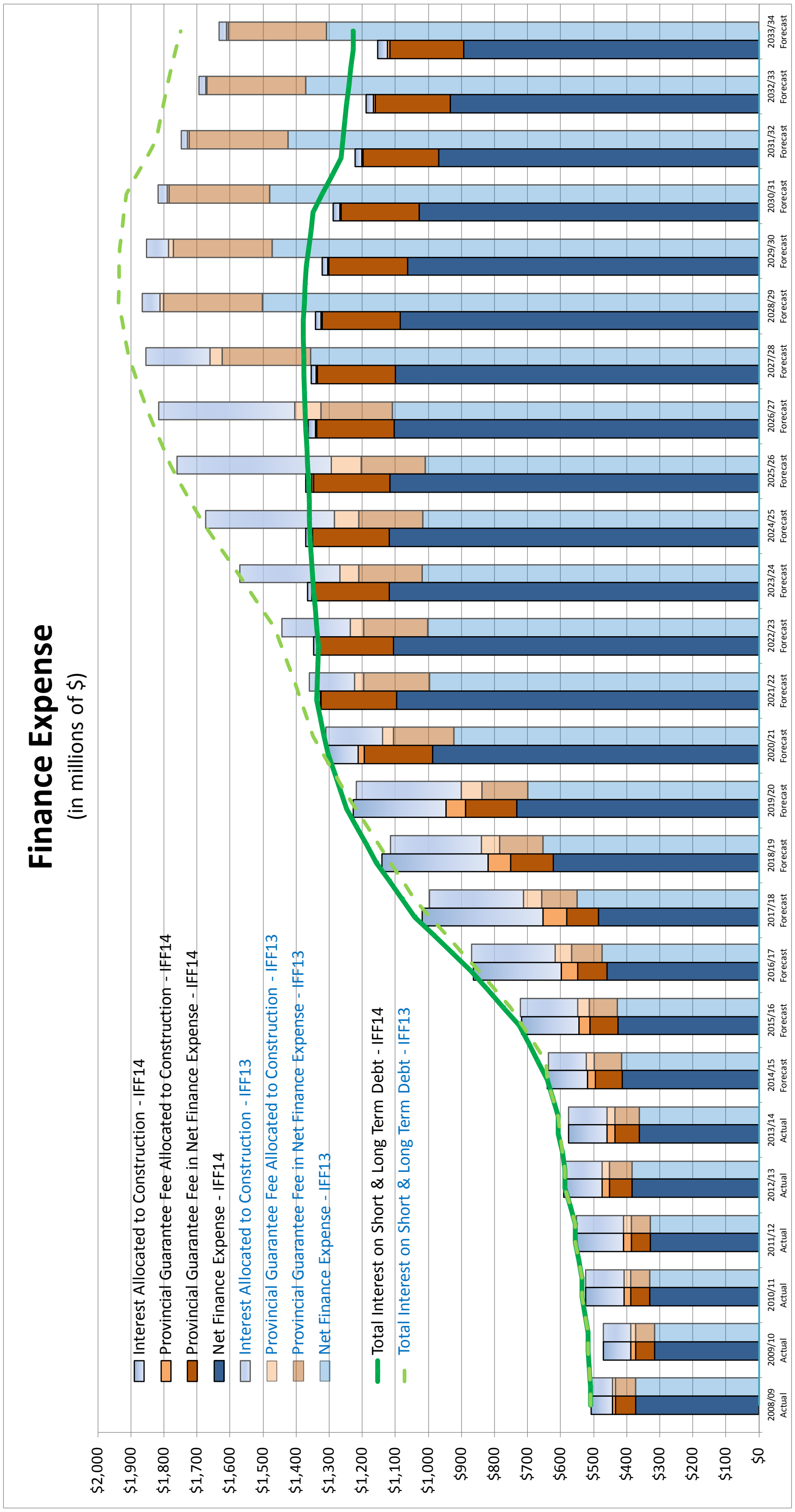
2024/25 Forecast
2025/26 Forecast
2026/27 Forecast
2027/28 Forecast
2028/29 Forecast
2029/30 Forecast
2030/31 Forecast
2031/32 Forecast
2032/33 Forecast
2033/34 Forecast

c) The second graph in this response adds a comparative plot of finance expense based on IFF13.



Section:	Tab 5: Section 5.7, Schedule 5.1.6	Page No.:	27
Topic:	Financial Results & Forecasts		
Subtopic:	Amortization Expense		
Issue:	Amortization Expense Detail		

PREAMBLE TO IR (IF ANY):

21T

QUESTION:

Please provide a breakdown by major component of rate regulated amortization expense in similar detail to CAC/MH I-14 (f) (2012 GRA) for 2012/13 through 2016/17 and indicate where the expenditures are included in the detail of depreciation and amortization expense in Schedule 5.1.6.

RATIONALE FOR QUESTION:

To understand how rate regulated balances, including Conawapa, impact revenue requirement in the application.

RESPONSE:

Please see the following table for a breakdown by major component and expenditure category in Schedule 5.1.6.

MANITOBA HYDRO
RATE REGULATED AMORTIZATION EXPENSE (000's)

	Schedule 5.1.6 Categorization	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Regulated Assets						
Power Smart programs - Electric	Generation - Demand Side Management	28 217	30 262	31 576	34 957	37 501
Conawapa	Other - Conawapa					7 711
Site Restoration Costs - General	Other - Miscellaneous	1 924	1 991	2 126	2 179	2 223
Site Restoration Costs - Diesel	Other - Miscellaneous	1 556	1 634	1 665	1 555	1 498
Acquisition Costs	Other - Miscellaneous	692	692	692	692	692
Regulatory Costs	Other - Miscellaneous	2 622	2 572	27	765	1 307
		$ 35 011	$ 37 151	$ 36 086	$ 40 149	$ 50 933

Section:	Tab 5 Appendix 5.4	Page No.:	Appendix 5.5 p. 6
Topic:	Financial Results & Forecasts		
Subtopic:	IFRS Transition		
Issue:	Transitional Adjustment Impact on Retained Earnings		

PREAMBLE TO IR (IF ANY):

MH is transitioning to IFRS in 2015/16 and will be restating 2014/15 for comparative purposes including adjustments to retained earnings.MH indicates that it expects to make transitional adjustments in particular the reclassification of pension actuarial experience losses to AOCI.

QUESTION:

Please provide details on the accounting entry for the reclassification of Pension actuarial experience losses to AOCI.

RATIONALE FOR QUESTION:

To understand how transitional adjustments are reflected on the financial forecasts.

RESPONSE:

Upon transition to IFRS, the net unamortized actuarial loss of $424 million will be reclassified from other long-term assets to accumulated other comprehensive income (AOCI) on the balance sheet. The net change in historical pension expense of $21 million will be reclassified from other long-term assets to retained earnings.

Section:	Tab 5 Appendix 5.4	**Page No.:**	Appendix 5.5 p. 6
Topic:	Financial Results & Forecasts		
Subtopic:	IFRS Transition		
Issue:	Transitional Adjustment Impact on Retained Earnings		

PREAMBLE TO IR (IF ANY):

MH is transitioning to IFRS in 2015/16 and will be restating 2014/15 for comparative purposes including adjustments to retained earnings.MH indicates that it expects to make transitional adjustments in particular the reclassification of pension actuarial experience losses to AOCI.

QUESTION:

Please indicate to what years the $445 million in actuarial experience losses relate.

RATIONALE FOR QUESTION:

To understand how transitional adjustments are reflected on the financial forecasts.

RESPONSE:

The $445 million is related to the fiscal years 2001 to 2014.

The $445 million is the total IFRS adjustment related to pensions. As the following table indicates, the net actuarial loss of $424 million is adjusted to AOCI and the change in historical pension expense of $21 million is adjusted to retained earnings.

Summary of Net Actuarial Gain (Loss) - IFRS Fair Value

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	Total
Schedule of net actuarial gain (loss)															
Actuarial gain (loss) on accrued benefit obligation	(9)	(14)	(37)	(6)	(21)	(6)	(27)	(22)	20	(9)	(26)	(147)	(197)	19	**(482)**
Actuarial gain (loss) on plan assets	(18)	(5)	(53)	73	22	68	35	(62)	(185)	80	41	(39)	15	87	**59**
	(26)	(19)	(91)	66	1	62	8	(84)	(165)	70	15	(186)	(183)	106	**(424)**

Retrospective Retained Earnings Adjustment (elimination of the corridor amortization, past service amortization, change in expected return on fund assets)**:** **(21)**

Appendix 5.4 Table **(445)**

Section:	Tab 5 Appendix 5.4	**Page No.:**	Appendix 5.5 p. 6
Topic:	Financial Results & Forecasts		
Subtopic:	IFRS Transition		
Issue:	Transitional Adjustment Impact on Retained Earnings		

PREAMBLE TO IR (IF ANY):

MH is transitioning to IFRS in 2015/16 and will be restating 2014/15 for comparative purposes including adjustments to retained earnings.MH indicates that it expects to make transitional adjustments in particular the reclassification of pension actuarial experience losses to AOCI.

QUESTION:

Please discuss the implications of this accounting change to financial reporting and how it is reflected in the IFF.

RATIONALE FOR QUESTION:

To understand how transitional adjustments are reflected on the financial forecasts.

RESPONSE:

The transitional adjustments reflected in the financial forecasts are:

1) Under Canadian GAAP, Manitoba Hydro used the corridor method of amortization for actuarial gains and losses related to the pension plans. The amortization of these gains and losses was recognized in pension expense on an annual basis when the cumulative unamortized net gain or loss exceeded 10% of the greater of the accrued benefit obligation or the market value of the plan assets at the beginning of the year. This excess was amortized to operating expenses over the estimated remaining service lives of employees covered by the plan.

The corridor accounting methodology has been eliminated under IFRS as IFRS requires the immediate recognition of actuarial gains and losses in AOCI in the period they occur. As a result, all changes in the value of the defined benefit obligation and in the value of plan assets are recognized in the period they occur in AOCI. This results in a reduction to pension expense.

2) Under Canadian GAAP, the expected return on plan assets was set at management discretion, looking at historical trends and future expectations. IFRS requires that the interest rate used to determine the expected return on plan assets is the same as the discount rate used to determine the obligation. This results in an increase in annual pension expense.

IFF14 reflects the remeasurement and restatement of pension expense and experience gains/losses of the net defined benefit obligation under IFRS beginning in the fiscal year 2015/16 with all retrospective transitional adjustments reflected in the April 1, 2015 opening balances for fiscal 2015/16. This will result in an opening balance adjustment of $424 million to AOCI and $21 million to retained earnings.

Section:	Tab 5 Appendix 5.4	**Page No.:**	Appendix 5.5 p. 6
Topic:	Financial Results & Forecasts		
Subtopic:	IFRS Transition		
Issue:	Transitional Adjustment Impact on Retained Earnings		

PREAMBLE TO IR (IF ANY):

MH is transitioning to IFRS in 2015/16 and will be restating 2014/15 for comparative purposes including adjustments to retained earnings.MH indicates that it expects to make transitional adjustments in particular the reclassification of pension actuarial experience losses to AOCI.

QUESTION:

Please indicate how the Pension and Benefits adjustments for discount rate changes in figure 5.5.5 would change based on IFRS IAS19. Please explain whether this amount should be indicated as an increase in operating costs under IFRS ?

RATIONALE FOR QUESTION:

To understand how transitional adjustments are reflected on the financial forecasts.

RESPONSE:

The pension and benefit adjustment identified in figure 5.5.5 relating to changes in discount rate would not change based on IFRS IAS 19 and as such there is no increase in operating costs under IFRS.

As discussed in Section 3.5.3 of the IFRS Status Update Report filed in Appendix 5.4, the Canadian GAAP requirement is similar to the IFRS standards. Manitoba Hydro determines an annual discount rate which complies with the recommendations of the Canadian Institute of Actuaries, GAAP and IFRS. Manitoba Hydro does not anticipate changing the manner in which it determines its annual discount rate upon transition to IFRS.

Section:	Tab 5	**Page No.:**	16, 17
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expense		
Issue:	Wages and Salaries		

PREAMBLE TO IR (IF ANY):

At the last GRA, MH was forecasting labor and benefits including overtime of $642.5 million for 2012/13 and $655.4 million for 2013/14.

QUESTION:

Please provide a detailed comparison of the wages and salaries, overtime and benefits forecast at last GRA for the years 2012/13 through 2016/17 and explain the variances.

RATIONALE FOR QUESTION:

OM&A costs are included in revenue requirement.

RESPONSE:

The following table provides a comparison of wages and salaries, overtime and benefits forecasted in IFF12 (as filed at the last GRA) against actual results for the years 2012/13 and 2013/14.

MANITOBA HYDRO
WAGES & SALARIES, OVERTIME AND BENEFITS

	2012/13 Actual	2012/13 Forecast	2012/13 Variance	%	2013/14 Actual	2013/14 Forecast	2013/14 Variance	%
Wages & Salaries	$ 466,165	$ 476,570	$ 10,404	2%	$ 480,511	$ 486,101	$ 5,590	1%
Overtime	61,031	56,005	(5,025)	-9%	62,365	57,126	(5,239)	-9%
Employee Benefits	130,886	117,264	(13,622)	-12%	157,094	126,002	(31,092)	-25%
Total	**$ 658,082**	**$ 649,839**	**$ (8,243)**	**-18%**	**$ 699,970**	**$ 669,229**	**$ (30,742)**	**-33%**

Wages & salaries are below forecast in both 2012/13 and 2013/14 as a result of the Corporation's continuing efforts to control costs. These reductions have been offset primarily by the impacts of changes in the discount rate on pension and other benefits.

Higher overtime costs in 2012/13 were required to address storm restoration work. The additional overtime in 2013/14 was related to increased capital construction requirements primarily for Bipole III, Pointe du Bois Spillway and NFAT activities and to provide assistance following the Trans Canada Pipeline explosion and Toronto Hydro storm. The additional overtime costs for both the Trans Canada Pipeline explosion and Toronto storm were offset in Operating Expense Recoveries.

A comparison of overall OM&A costs between IFF12 and IFF14 for 2014/15 through 2016/17 is provided in Coalition/MH I-14e. Detailed forecasts providing wage and salary, overtime and benefit costs were only prepared for the 2012/13 and 2013/14 test years at the last GRA.

Section:	Tab 5	Page No.:	16, 17
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expense		
Issue:	Wages and Salaries		

PREAMBLE TO IR (IF ANY):

At the last GRA, MH was forecasting labor and benefits including overtime of $642.5 million for 2012/13 and $655.4 million for 2013/14.

QUESTION:

Please file a copy of any actuarial revaluation to support the changes to benefits from that indicated at the last GRA.

RATIONALE FOR QUESTION:

OM&A costs are included in revenue requirement.

RESPONSE:

The primary driver for changes in benefits costs is related to pension expense on the MHEB core plan. Actuarial valuations are attached for the plan for 2011, 2012 and 2013. Please see the attachments to this response.

The valuations indicate the actuarial liability at the December 31 for each of the years. Manitoba Hydro rolls this amount forward to calculate the liability as at March 31ST for financial statement purposes.

Past service pension expense under Canadian GAAP includes interest on the liability, amortization of corridor (actuarial gains/losses) and management fees, partially offset by the expected return on the pension asset.

Current service pension expense is calculated by applying the employee contribution percentage and the employer contribution rate (as provided in the actuarial valuation) to pensionable earnings. Pensionable earnings, employee contribution rates and employer contribution rates have all increased resulting in an increase to current service pension costs. The forecast assumes the employee contribution rates remain at the January 2015 level and the employer contribution rate remains constant at 124.5% over the forecast period.

The following table provides the employee contribution percentages before and after yearly maximum pensionable earnings (YMPE).

Employee Contributions

	up to YMPE	after YMPE	YMPE
up to December 2012	6.5%	7.5%	50 100
December 2012- December 2013	7.0%	8.0%	51 100
December 2013 - December 2014	7.5%	8.5%	52 500
January 2015 forward	8.0%	9.0%	53 600

The following table provides the employer contribution rates based on the actuarial valuations.

Employer Contributions

Valuation Date	Applies to fiscal year	Rate
December 31, 2011	2012-13	121.5%
December 31, 2012	2013-14	139.8%
December 31, 2013	2014-15	124.5%

ACTUARIAL REPORT

(for pension expense purposes)

on the Pension Liabilities which the

MANITOBA HYDRO-ELECTRIC BOARD

has as at

DECEMBER 31, 2011

(as a result of participation of its employees in the Civil Service Superannuation Act)

June, 2012

Prepared by:

ELLEMENT & ELLEMENT
CONSULTING ACTUARIES

TABLE OF CONTENTS

APPENDICES

1. PURPOSE

The purpose of this Report is to:

- indicate the liabilities which the Manitoba Hydro-Electric Board (Manitoba Hydro) has at December 31, 2011, as a result of the participation of its employees in the Civil Service Superannuation Act (Superannuation Act), and
- provide a formula which can be used to estimate the increase in these liabilities in the following 12 to 18 months after December 31, 2011.

These liabilities are an estimate of the present value of the future payments which Manitoba Hydro is expected to make to the Civil Service Superannuation Fund (Fund).

The liabilities have been computed on a going concern basis. This basis contemplates the continued existence of the pension plan and the funding arrangements for the benefits under the pension plan.

The guidance for the calculation of the liabilities and the preparation of this Report are the Practice-Specific Standards for Pension Plans of the Canadian Institute of Actuaries and IAS 19, Employee Benefits issued by the International Accounting Standards Committee.

2. DATA

It is anticipated no amendments will be made to the Superannuation Act or if amendments are made, they will not affect Manitoba Hydro's pension liabilities.

The data used in the calculations includes the portion of each pension, currently in payment or which is expected to be in payment, that Manitoba Hydro is responsible for.

The data on the pensions in payment and the accrued pensionable service of employees was provided by the Civil Service Superannuation Board (Superannuation Board).

Information on the pensions and benefits paid by Manitoba Hydro and the employee contributions for 2011 were obtained from the Superannuation Board.

The data was checked for missing information, illogical information and reconciled with the prior valuation data. A few minor changes to the data resulted from the checks made.

3. MEMBERSHIP

The data provided indicated that Manitoba Hydro was the employer of record for the following participants:

	December 31, 2011			December 31, 2010		
	Males	Females	Total	Males	Females	Total
Pensioners	2,617	334	2,951	2,482	284	2,766
Deferred Pensioners	155	74	229	145	66	211
Contributors	4,408	1,467	5,875	4,447	1,486	5,933
TOTAL	7,180	1,875	9,055	7,074	1,836	8,910

A reconciliation of the number of member records used in the calculations is shown in Appendix I.

The numbers shown for deferred pensioners includes 11 reciprocal transfer records at December 31, 2011 and 11 at December 31, 2010.

The numbers shown for pensioners includes 557 beneficiary records at December 31, 2011 and 561 at December 31, 2010.

4. ASSUMPTIONS

The assumptions used in this valuation and the assumptions used in the last valuation of the Manitoba Hydro pension liabilities are shown in Appendix II.

The selection of the demographic assumptions is made by the actuary. The demographic assumptions have been developed from the most current accumulated experience of the CSSF. This experience is reflected in the demographic assumptions adopted for the valuations of the CSSF. The last changes to these assumptions were made for the valuation of the CSSF as at December 31, 2009. These demographic assumptions have been adopted for this Report.

The selection of the economic assumptions is made by management with consultation provided by the actuary. The economic assumptions adopted for this Report, by management have been changed from those used in the last valuation of the Manitoba Hydro pension liabilities as at December 31, 2010. In particular, the discount rate has been reduced from 6.50% to 5.25% for this valuation.

The selection of the assumptions is for the most part on a best estimate basis plus a small allowance for adverse deviation.

5. MANITOBA HYDRO SHARE OF BENEFIT PAYMENTS

The benefits expected to be paid are based on the provisions of the Superannuation Act.

Manitoba Hydro is expected to make payments due to:

- pensions in payment at December 31, 2011 for which Manitoba Hydro is responsible as a result of service with Manitoba Hydro,
- pensions expected to become payable to former employees who retained the right to a deferred paid-up pension, and
- pensions and other benefits expected to become payable to existing employees as a result of service completed up to the valuation date.

At present, Manitoba Hydro is contributing to the Fund based on the pay-as-you-go method of funding. Under this method, no advance funding payments for the employer share of the cost of pensions are made to the Fund. Manitoba Hydro has, however, established a separate pension fund which is being credited with interest earnings and employer contributions. It is intended that this separate fund be maintained to meet the Manitoba Hydro pension liabilities.

Each month, Manitoba Hydro makes payments to the Fund to reimburse it for:

- a portion (currently about 47%) of each pension payment to retired employees,
- a portion (currently about 47%) of each pension payment to a beneficiary of a deceased pensioner or the survivor of an employee who dies in service,
- the interest portion of any cash settlement paid to the beneficiary of an employee who dies in service,
- a portion of any amounts transferred to other pension plans under reciprocal agreements,
- a portion of any commuted values paid out as a result of employees terminating service or as a result of marriage breakdowns, and
- a portion of the administrative costs of operating the Fund in respect of Manitoba Hydro records.

Pensions in payment are indexed to 2/3 of the increases in the cost of living, provided sufficient funds exist to finance such increases. Former employees who retain a right to a deferred paid-up pension have these pensions indexed during both the deferral period and the pay-out period.

The employer share of each pension is based on when the pension starts. For pensions which commenced:

(a) prior to March 31, 1961, the employer is responsible for a portion of each increase in that pension, and

(b) after March 31, 1961, the employer is responsible for a portion (currently about 47%) of the pension paid.

The interest portion of each cash settlement is calculated by adding interest to contributions from the midpoint of the year of contribution to the date of payment to the beneficiary. Contributions made for service prior to January 1, 1984 are credited with interest at the rate of 3% per year. Contributions made for service after this date are credited with interest based on the interest rates available on 5-year fixed term deposits.

Pursuant to CSSA subsection 22(11), employer funding for employees who have service with more than one non-matching Agency shall be on a pro rata basis. This proration of the benefits assigned to an employer is based on the proration of service allocated to the employer. This proration assignment was made effective for events on or after January 1, 1998. This may decrease or increase the pension obligations in the absence of CSSA subsection 22(11). However, for enhanced benefits, it is the administrative practice to bill all of the enhanced benefits to the current employer.

6. VALUATION PROCEDURE

The accrued benefit actuarial cost method with salary projection has been used to determine the accrued liabilities and the current service cost for basic benefits applicable to each year after the valuation date. Under this method, the accrued liabilities are equal to the amount needed to fund the projected benefits accrued for service up to the valuation date. The current service cost or normal cost is equal to the estimated cost of projected benefits expected to accrue for service in the year following the valuation date.

The accrued liabilities for prior indexing adjustments are financed by a portion of the accrued assets in the COLA Account. The excess of the accrued assets plus future contributions at 10.2% of employees' contributions plus special allocations from time to time plus interest are used to finance targeted indexing adjustments of 2/3 of inflation. For this Report, all excess assets over accrued liabilities are held as a future obligation of the COLA Account. In addition, we have included an amount equal to 10.2% of employees' contributions as the indexing current service cost included in the total current service cost.

7. VALUATION RESULTS

The following table shows the accrued liabilities which Manitoba Hydro has at December 31, 2011 and December 31, 2010 as a result of the participation of its employees and former employees in the Superannuation Act:

	after change in assumptions			*before change in assumptions*					
	December 31, 2011			December 31, 2011			December 31, 2010		
	BASIC	COLA	TOTAL	BASIC	COLA	TOTAL	BASIC	COLA	TOTAL
Pensioners	$404,401,000	$50,192,800	$ 454,593,800	$361,205,300	$47,442,400	$408,647,700	$317,101,300	$43,313,300	$360,414,600
Deferred Pensioners	6,364,900	-	6,364,900	5,344,900	-	5,344,900	5,238,500	-	5,238,500
Contributors	496,951,500	-	496,951,500	410,550,200	-	410,550,200	405,838,300	-	405,838,300
Reserves									
- asset smoothing	-	-	-	-	-	-	-	-	-
- strenghtening assumptions	-	-	-	-	-	-	-	-	-
- contribution deficiency	10,237,500	-	10,237,500	10,237,500	-	10,237,500	7,729,000	-	7,729,000
- 30 year run off - 1986	-	1,932,200	1,932,200	-	1,971,800	1,971,800	-	2,572,900	2,572,900
- 30 year run off - 2004	-	29,509,300	29,509,300	-	30,114,600	30,114,600	-	32,048,900	32,048,900
- Amount to finance future adjustments	-	7,395,100	7,395,100	-	7,546,800	7,546,800	-	13,564,100	13,564,100
TOTAL	$917,954,900	$89,029,400	$1,006,984,300	$787,337,900	$87,075,600	$874,413,500	$735,907,100	$91,499,200	$827,406,300

The expected average remaining service life (EARSL) of the employees who are contributors to the Fund at the valuation date is 13 years.

8. PROJECTION FORMULA FOR LIABILITIES

The reconciliation of the change in accrued liabilities for 2011 is shown in Appendix III.

The following formula can be used to project the estimated increase in liabilities in the 12 to 18 months after the valuation date:

- Add interest at the rate of 5.25% per year to the liabilities at the beginning of the period.

  The interest addition for the current service cost and the payments from the accounts should be prorated to recognize investment for half the period, on average.
- Add employer contributions at the rate of 121.5% of the employee contributions required to be made for the period.
- Deduct the actual employer pension and benefit payments made to the Fund for the period.

9. ACCOUNTING FOR PENSION OBLIGATIONS

Pursuant to the Agreement in principle between Manitoba Hydro and the Unions (the Agreement), the previously established pension fund known as the Manitoba Hydro Pension Fund (MHPF) is to be used solely for the benefit of retired, current and future employees of Manitoba Hydro who are participants in the CSSF and those former employees entitled to deferred pensions.

The dedication of future surpluses as a benefit for employees and former employees will impact the determination of Manitoba Hydro's pension expense.

The pension expense for a period is normally equal to the following components:

(a) current service cost,

(b) plus interest on accrued benefit obligations,

(c) less expected interest on assets,

(d) plus amount of past service cost,

(e) plus amount of actuarial gains/losses,

(f) plus amount of transitional asset/obligations.

There will be a transitioning period as Manitoba Hydro moves from it's previously existing method of determining the pension expense to the CSSF Approach and the associated Pension Liabilities under the MHPF. This process commenced with the 2007 pension expense report.

10. ACTUARIAL OPINION

In our opinion, for the purposes of this Report:

- The membership data is sufficient and reliable.
- The assumptions, in aggregate which have been used, are appropriate for the purpose of determining the accounting requirements of the Plan on a going concern basis.
- The method which has been used is appropriate for the purpose of determining the accounting requirements of the Plan on a going concern basis.
- We are not aware of any other matters or events occurring since the completion of this Report, which will materially affect the calculation of the liabilities as at December 31, 2011.
- This Report has been prepared and my opinion given in accordance with accepted actuarial practice in Canada.

DATED at Winnipeg, this 29th day of June, 2012.

ELLEMENT & ELLEMENT

Louis Ellement

Louis Ellement, F.S.A., F.C.I.A.
MH rpt 2011.doc

APPENDIX I

▪ Reconciliation of Membership

	Contributors			Deferred Pensioners			Reciprocal Transfers			Pensions in Payment		
	Males	Females	Total	Males	Females	Total	Males	Females	Total	Males	Females	Total
December 31, 2010	4,447	1,486	5,933	136	64	200	9	2	11	2,482	284	2,766
Adjustments	3	(1)	2	(1)	-	(1)	-	-	-	(1)	-	(1)
Retirements from Disability	-	-	-	-	-	-	-	-	-	-	-	-
New Contributors	213	58	271	-	-	-	-	-	-	-	-	-
Contributor Deaths:												
- cash/transfer	(4)	(2)	(6)	-	-	-	-	-	-	-	-	-
- beneficiary pension	(4)	-	(4)	(1)	-	(1)	-	-	-	5	-	5
Terminations:												
- cash/transfer	(45)	(12)	(57)	(1)	-	(1)	-	-	-	-	-	-
- deferred pension	(6)	(6)	(12)	6	6	12	-	-	-	-	-	-
- reciprocal transfer	1	3	4	(1)	-	(1)	-	-	-	-	-	-
- pending	(25)	(7)	(32)	17	3	20	-	-	-	-	-	-
Disablements	-	-	-	-	-	-	-	-	-	3	-	3
Retirements	(172)	(52)	(224)	(9)	(1)	(10)	-	-	-	182	53	235
Pensioner Deaths:												
- pension ceases	-	-	-	-	-	-	-	-	-	(54)	(3)	(57)
- pension continues	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2011	4,408	1,467	5,875	146	72	218	9	2	11	2,617	334	2,951

▪ Contributors

MALES — **NUMBER OF MEMBERS IN EACH YEARS OF SERVICE CELL**

Age	Count	Average Service	Average Salary	0 - 4	5 - 9	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 - 39	40 - 44	45 - 49
15 - 19	4	0.21	$ 34,562	4	-	-	-	-	-	-	-	-	-
20 - 24	215	1.94	42,592	209	6	-	-	-	-	-	-	-	-
25 - 29	531	3.89	55,492	382	146	3	-	-	-	-	-	-	-
30 - 34	552	6.07	64,598	248	199	105	-	-	-	-	-	-	-
35 - 39	506	8.34	69,913	165	126	178	36	1	-	-	-	-	-
40 - 44	553	12.26	74,251	106	99	152	80	114	2	-	-	-	-
45 - 49	733	17.92	78,584	75	64	133	53	251	150	7	-	-	-
50 - 54	600	20.98	79,106	42	34	113	31	132	136	104	8	-	-
55 - 59	481	25.94	79,704	16	19	68	25	68	62	84	138	1	-
60 - 64	179	26.91	82,030	9	10	32	3	12	16	23	60	14	-
65 - 69	50	31.28	79,568	4	1	2	1	7	2	8	11	13	1
70 - 74	4	11.10	50,014	2	-	1	-	-	1	-	-	-	-
2011 Tot/Avg	4,408	13.94	$ 71,035	1,262	704	787	229	585	369	226	217	28	1
2010 Tot/Avg	4,447	14.30	$ 68,090	1,274	924	465	295	600	333	246	281	27	2

FEMALES — **NUMBER OF MEMBERS IN EACH YEARS OF SERVICE CELL**

Age	Count	Average Service	Average Salary	0 - 4	5 - 9	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 - 39	40 - 44	45 - 49
15 - 19	1	0.08	$ 30,141	1	-	-	-	-	-	-	-	-	-
20 - 24	30	1.67	41,588	29	1	-	-	-	-	-	-	-	-
25 - 29	113	3.34	53,839	91	22	-	-	-	-	-	-	-	-
30 - 34	155	5.25	63,646	81	62	12	-	-	-	-	-	-	-
35 - 39	181	6.97	66,704	64	70	47	-	-	-	-	-	-	-
40 - 44	183	10.34	68,689	38	58	43	29	14	1	-	-	-	-
45 - 49	316	15.95	66,611	40	39	73	33	76	50	5	-	-	-
50 - 54	295	18.13	67,665	20	27	88	27	48	47	36	2	-	-
55 - 59	128	19.21	64,526	2	15	37	15	26	9	15	9	-	-
60 - 64	56	20.17	62,903	1	4	19	6	9	6	3	5	3	-
65 - 69	9	21.83	51,972	-	1	1	1	4	1	-	-	1	-
70 - 74	-	-	-	-	-	-	-	-	-	-	-	-	-
2011 Tot/Avg	1,467	12.66	$ 64,847	367	299	320	111	177	114	59	16	4	-
2010 Tot/Avg	1,486	12.58	$ 61,406	379	446	147	150	184	103	47	25	5	-

- ## Pensions in Payment

MALES

Age	Count for Basic	Average Basic Pension	Count for Cola	Average Cola Pension
35 - 39	-	$ -	-	$ -
40 - 44	1	545.10	1	50.34
45 - 49	8	506.88	6	29.98
50 - 54	12	798.77	11	50.13
55 - 59	256	3,086.57	153	92.38
60 - 64	490	2,797.91	437	156.57
65 - 69	558	2,409.05	535	287.54
70 - 74	359	2,042.62	357	403.06
75 - 79	318	1,667.11	317	479.98
80 - 84	262	1,360.06	262	523.73
85 - 89	184	970.33	184	548.58
90 - 94	127	549.83	127	451.44
95 - 99	34	252.82	34	345.35
>99	8	218.22	8	496.43
2011 Tot/Avg	2,617	$ 2,062.69	2,432	$ 347.21
2010 Tot/Avg	2,482	$ 1,964.68	2,369	$ 327.78

FEMALES

Age	Count for Basic	Average Basic Pension	Count for Cola	Average Cola Pension
35 - 39	-	$ -	-	$ -
40 - 44	2	532.78	2	23.55
45 - 49	2	370.53	1	35.72
50 - 54	1	493.53	1	49.68
55 - 59	65	2,326.07	36	59.25
60 - 64	83	1,684.94	70	92.29
65 - 69	65	1,308.33	59	126.48
70 - 74	55	1,082.84	51	171.11
75 - 79	24	825.45	24	212.25
80 - 84	22	877.23	22	280.83
85 - 89	11	511.12	11	214.63
90 - 94	3	475.28	3	385.54
95 - 99	1	485.52	1	363.84
>99	-	-	-	-
2011 Tot/Avg	334	$ 1,450.86	281	$ 142.59
2010 Tot/Avg	284	$ 1,296.42	261	$ 131.51

Notes:

1. Both the pension amounts and cost-of-living (cola) amounts shown in the above table are the total amounts paid.
2. Counts are based on the primary pensioner sex.

- **Deferred Pensioners**

MALES

Age	Count	Average Basic Pension
20 - 24	2	$ 87.08
25 - 29	8	133.31
30 - 34	14	275.86
35 - 39	10	181.23
40 - 44	17	780.01
45 - 49	41	668.79
50 - 54	31	808.62
55 - 59	14	503.99
60 - 64	7	459.05
65 - 69	2	176.51
2011 Tot/Avg	146	$ 570.45
2010 Tot/Avg	136	$ 587.98

FEMALES

Age	Count	Average Basic Pension
20 - 24	1	$ 7.57
25 - 29	-	-
30 - 34	6	299.41
35 - 39	6	91.56
40 - 44	14	646.10
45 - 49	21	448.58
50 - 54	14	228.23
55 - 59	6	890.59
60 - 64	2	241.71
65 - 69	2	225.60
2011 Tot/Avg	72	$ 420.73
2010 Tot/Avg	64	$ 409.38

APPENDIX II

Summary of Actuarial Assumptions - Pension

		December 31, 2011	December 31, 2010
1.	Actuarial cost method	ABCM with salary projection	same
2.	Discount Rate for benefits		
	▪ Basic Part	5.25%	6.50%
	▪ COLA Liabilities	5.25%	6.00%
	Annual Rate of Inflation Included in Discount Rate	2.00%	2.50%
3.	General salary increases (service and merit is separate and age specific)		
	▪ general salary increase rate for year after valuation date	2.75%	3.25%
	▪ general salary increase rate for future periods	2.75%	3.25%
4.	Annual Salary Merit Increases	see Table	same
5.	Indexing of Pensions (2/3 of the assumed rate of inflation)	1.33%	1.67%
6.	Annual Increase in Earnings under Canada Pension Plan	2.75%	3.25%
7.	Annual Increase in Maximum Pension under Income Tax Act	2012: $2,646.67 Indexed ≥ 2013: 2.75%	same
8.	Annual Rate of Interest Credited to Employee Contributions	3.25%	4.50%
9.	Employer Portion of Administrative Costs - % of employee contributions	nil	0.81%
10.	Annual Rates of Death	UP2020	same
11.	Proportion of Employees with a Spouse	see Table	same
12.	Annual Rates of Termination of Service	see Table	same
13.	Annual Rates of Disability	see Table	same
14.	Annual Rates of Retirement	see Table	same
15.	Reserves	23.89% of corresponding CSSF Amounts	24.38% of corresponding CSSF Amounts

	Mortality-UP2020		Termination		Disability		Retirement	
Age	Males	Females	Males	Females	Males	Females	Males	Females
20	0.03%	0.02%	10.15%	12.60%	-	-	-	-
25	0.05	0.02	6.60	9.20	-	-	-	-
30	0.08	0.03	4.63	6.88	-	-	-	-
35	0.08	0.04	3.39	5.31	0.01%	0.01%	-	-
40	0.09	0.05	2.58	4.26	0.04	0.06	-	-
45	0.12	0.07	2.06	3.64	0.09	0.13	-	-
50	0.17	0.10	1.71	3.22	0.23	0.30	-	-
55	0.29	0.20	0.00	0.00	0.66	0.76	24.86%	24.49%
60	0.56	0.42	0.00	0.00	-	-	27.10	21.45
65	1.08	0.82	-	-	-	-	100.00	100.00
70	1.72	1.30	-	-	-	-	-	-
75	2.77	1.98	-	-	-	-	-	-
80	5.14	3.53	-	-	-	-	-	-
85	8.71	6.23	-	-	-	-	-	-
90	14.82	11.56	-	-	-	-	-	-
95	23.84	19.01	-	-	-	-	-	-
100	33.24	28.96	-	-	-	-	-	-

	Service and Merit		Married Proportions	
Age	Males	Females	Males	Females
20	3.00%	3.00%	33.00%	35.00%
25	2.50	2.50	69.00	55.00
30	2.00	2.00	90.00	68.40
35	1.50	1.50	92.70	70.50
40	1.00	1.00	93.30	70.00
45	0.50	0.50	93.50	67.80
50	0.25	0.25	90.00	71.00
55	0.00	0.00	90.00	71.00
60	0.00	0.00	90.00	71.00
65	0.00	0.00	90.00	71.00

Based on the distribution of employees by age and sex at the valuation date, the average rate of service and merit is 0.87%.

Plus allowance for use of accrued vacation in calculation of average annual salary at date of retirement: 3.45%.

APPENDIX III

Reconciliation of Change in Manitoba Hydro Accrued Pension Liabilities for 2011

1.	**Actuarial Liabilities net of reserves at December 31, 2010** before reserves	$ 771,491,400
2.	Additional Liability for a new retirement not previously recognized	385,000
3.	Interest on liabilities and cash flow (*6.50% & 6.00% (COLA)*)	49,615,200
4.	Employer Contributions (CSC for 2011 / Cost of in year COLA)	29,411,500
5.	Employer Benefit Payments	(39,806,600)
6.	**Projected Liabilities net of reserves at December 31, 2011** before reserves	$ 811,096,500
7.	**ACTUAL LIABILITIES** net of reserves at December 31, 2011 before change in assumptions	$ 824,542,800
8.	**ACTUAL LIABILITIES** net of reserves at December 31, 2011 after change in assumptions	$ 957,910,200
9.	**RESERVES AT 31-DEC-2010 (2010 factors)**	$ 55,914,900
10.	**RESERVES AT 31-DEC-2011 (2011 factors)**	49,074,100
11.	**ACTUAL LIABILITIES** plus Reserves at December 31, 2011	$ 1,006,984,300
	GAIN/(LOSS) due to actual experience: [6] - [7] (Note 1)	$ (13,446,300)
	GAIN/(LOSS) due to change in assumptions: [7] - [8] (Note 2)	$ (133,367,400)
	GAIN/(LOSS) due to change in reserves: [9] - [10] (Note 3)	$ 6,840,800

Note 1: IMPACT OF ACTUAL EXPERIENCE vs EXPECTED EXPERIENCE

	GAIN/(LOSS)
1. Salary change impact: A:E (5.31% : 3.55%)	$ (6,647,100)
2. Retirement Experience: A:E (244: 207)	(3,491,600)
3. Termination Experience: A:E values	(4,201,700)
4. Mortality Experience: A:E (48: 57)	57,700
5. Other DEMOGRAPHIC Experience:	836,400
Total effect of all Experience	$ (13,446,300)

The other demographic experience is the unallocated amount for which a precise allocation could not be easily identified.
This amount is within the tolerance level of 0.50% of total liabilities.

Note 2: IMPACT OF CHANGE IN ASSUMPTIONS

		GAIN/(LOSS)
1.	Decrease in interest rate from 6.50%/6.00% to 5.25%/5.25%	$ (133,367,400)
		-
	Total effect of change in assumptions	$ (133,367,400)

Note 3: IMPACT OF CHANGE IN RESERVES

		GAIN/(LOSS)
1.	Reserve for contribution deficiency	$ (2,508,500)
2.	Reserve for 30-yr run off of 1986 transfer	640,700
3.	Reserve for 30-yr run off re delayed 2004 transfer	2,539,600
4.	Reserve for future adjustments (surplus)	6,169,000
	Total effect of change in reserves	$ 6,840,800

Actuarial Valuation Report as at December 31, 2012
(for pension expense purposes)

Manitoba Hydro-Electric Board
Liabilities for Pension Benefits
(as a result of participation of its employees in the Civil Service Superannuation Act)

Submitted: May, 2013

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APPENDICES

1. PURPOSE

The purpose of this Actuarial Valuation Report (Report) is to:

- indicate the liabilities which the Manitoba Hydro-Electric Board (Manitoba Hydro) has as at December 31, 2012 (Valuation Date), as a result of the participation of its employees in the Civil Service Superannuation Act (Superannuation Act), and
- provide a formula which can be used to estimate the increase in these liabilities in the following 12 to 18 months after December 31, 2012.

These liabilities are an estimate of the present value of the future payments which Manitoba Hydro is expected to make to the Civil Service Superannuation Fund (Fund).

The liabilities have been computed on a going concern basis. This basis contemplates the continued existence of the pension plan and the funding arrangements for the benefits under the pension plan.

The guidance for the calculation of the liabilities and the preparation of this Report are the Practice-Specific Standards for Pension Plans of the Canadian Institute of Actuaries and the International Accounting Standards Committee.

2. DATA

It is anticipated no amendments will be made to the Superannuation Act or if amendments are made, they will not affect Manitoba Hydro's pension liabilities.

The data used in the calculations includes the portion of each pension, currently in payment or which is expected to be in payment, that Manitoba Hydro is responsible for.

The data on the pensions in payment and the accrued pensionable service of employees was provided by the Civil Service Superannuation Board (Superannuation Board).

Information on the pensions and benefits paid by Manitoba Hydro and the employee contributions for 2012 were obtained from the Superannuation Board.

The data was checked for missing information, illogical information and reconciled with the prior valuation data. A few minor changes to the data resulted from the checks made.

3. MEMBERSHIP

The data provided indicated that Manitoba Hydro was the employer of record for the following participants:

	31-Dec-2012			31-Dec-2011		
	Males	Females	Total	Males	Females	Total
Actives	4,508	1,500	6,008	4,408	1,467	5,875
Deferreds	162	76	238	155	74	229
Pensioners & Survivors	2,178	874	3,052	2,617	334	2,951
Total	6,848	2,450	9,298	7,180	1,875	9,055

A reconciliation of the number of member records used in the calculations is shown in Appendix I.

The numbers shown for deferred pensioners includes 11 reciprocal transfer records at December 31, 2012 and 11 at December 31, 2011.

The numbers shown for pensioners includes 563 beneficiary records at December 31, 2012 and 557 at December 31, 2011.

4. ASSUMPTIONS

The assumptions used in this valuation and the assumptions used in the last valuation of the Manitoba Hydro pension liabilities are shown in Appendix II.

The selection of the demographic assumptions is made by the actuary. The demographic assumptions have been developed from the most current accumulated experience of the CSSF. This experience is reflected in the demographic assumptions adopted for the valuations of the CSSF. The last changes to these assumptions were made for the valuation of the CSSF as at December 31, 2011. These demographic assumptions have been adopted for this Report.

The selection of the economic assumptions is made by management with consultation provided by the actuary. The economic assumptions adopted for this Report, by management have been changed from those used in the last valuation of the Manitoba Hydro pension liabilities as at December 31, 2011. In particular, the discount rate has been reduced from 5.25% to 4.25% for this Report.

The selection of the assumptions is for the most part on a best estimate basis plus a small allowance for adverse deviation.

5. MANITOBA HYDRO SHARE OF BENEFIT PAYMENTS

The benefits expected to be paid are based on the provisions of the Superannuation Act.

Manitoba Hydro is expected to make payments due to:

- pensions in payment at December 31, 2012 for which Manitoba Hydro is responsible as a result of service with Manitoba Hydro,
- pensions expected to become payable to former employees who retained the right to a deferred paid-up pension, and
- pensions and other benefits expected to become payable to existing employees as a result of service completed up to the valuation date.

At present, Manitoba Hydro is contributing to the Fund based on the pay-as-you-go method of funding. Under this method, no advance funding payments for the employer share of the cost of pensions are made to the Fund. Manitoba Hydro has, however, established a separate pension fund which is being credited with interest earnings and employer contributions. It is intended that this separate fund be maintained to meet the Manitoba Hydro pension liabilities.

Each month, Manitoba Hydro makes payments to the Fund to reimburse it for:

- a portion (currently about 47%) of each pension payment to retired employees,
- a portion (currently about 47%) of each pension payment to a beneficiary of a deceased pensioner or the survivor of an employee who dies in service,
- the interest portion of any cash settlement paid to the beneficiary of an employee who dies in service,
- a portion of any amounts transferred to other pension plans under reciprocal agreements,
- a portion of any commuted values paid out as a result of employees terminating service or as a result of marriage breakdowns, and
- a portion of the administrative costs of operating the Fund in respect of Manitoba Hydro records.

Pensions in payment are indexed to 2/3 of the increases in the cost of living, provided sufficient funds exist to finance such increases. Former employees who retain a right to a deferred paid-up pension have these pensions indexed during both the deferral period and the pay-out period.

The employer share of each pension is based on when the pension starts. For pensions which commenced:

(a) prior to March 31, 1961, the employer is responsible for a portion of each increase in that pension, and

(b) after March 31, 1961, the employer is responsible for a portion (currently about 47%) of the pension paid.

The interest portion of each cash settlement is calculated by adding interest to contributions from the midpoint of the year of contribution to the date of payment to the beneficiary. Contributions made for service prior to January 1, 1984 are credited with interest at the rate of 3% per year. Contributions made for service after this date are credited with interest based on the interest rates available on 5-year fixed term deposits.

Pursuant to CSSA subsection 22(11), employer funding for employees who have service with more than one non-matching Agency shall be on a pro rata basis. This proration of the benefits assigned to an employer is based on the proration of service allocated to the employer. This proration assignment was made effective for events on or after January 1, 1998. This may decrease or increase the pension obligations in the absence of CSSA subsection 22(11). However, for enhanced benefits, it is the administrative practice to bill all of the enhanced benefits to the current employer.

6. VALUATION PROCEDURE

The accrued benefit actuarial cost method with salary projection has been used to determine the accrued liabilities and the current service cost for basic benefits applicable to each year after the valuation date. Under this method, the accrued liabilities are equal to the amount needed to fund the projected benefits accrued for service up to the valuation date. The current service cost or normal cost is equal to the estimated cost of projected benefits expected to accrue for service in the year following the valuation date.

The accrued liabilities for prior indexing adjustments are financed by a portion of the accrued assets in the COLA Account. The excess of the accrued assets plus future contributions at 10.2% of employees' contributions plus special allocations from time to time plus interest are used to finance targeted indexing adjustments of 2/3 of inflation. For this Report, all excess assets over accrued liabilities are held as a future obligation of the COLA Account. In addition, we have included an amount equal to 10.2% of employees' contributions as the indexing current service cost included in the total current service cost.

7. VALUATION RESULTS

The following table shows the accrued liabilities which Manitoba Hydro has at December 31, 2012 and December 31, 2011 as a result of the participation of its employees and former employees in the Superannuation Act:

	31-Dec-2012			31-Dec-2011		
	BASIC	COLA	TOTAL	BASIC	COLA	TOTAL
Actives	$ 635,854,400	$ -	$ 635,854,400	$496,951,500	$ -	$ 496,951,500
Deferreds	7,155,600	-	7,155,600	6,364,900	-	6,364,900
Pensioners & Survivors	466,024,300	60,089,700	526,114,000	404,401,000	50,192,800	454,593,800
Reserves						
- asset smoothing	-	-	-	-	-	-
- strenghtening assumptions	-	-	-	-	-	-
- adverse experience	-	-	-	-	-	-
- contribution deficiency	11,833,800	-	11,833,800	10,237,500	-	10,237,500
- 30 year run off - 1986	-	1,610,000	1,610,000	-	1,932,200	1,932,200
- 30 year run off - 2004	-	31,746,300	31,746,300	-	29,509,300	29,509,300
- Amount to finance future adjustments	-	8,284,500	8,284,500	-	7,395,100	7,395,100
Total	$ 1,120,868,100	$ 101,730,500	$1,222,598,600	$917,954,900	$89,029,400	$1,006,984,300

The expected average remaining service life (EARSL) of the employees who are contributors to the Fund as at the Valuation Date is 13 years.

8. PROJECTION FORMULA FOR LIABILITIES

The reconciliation of the change in accrued liabilities for 2012 is shown in Appendix III.

The following formula can be used to project the estimated increase in liabilities in the 12 to 18 months after the valuation date:

- Add interest at the rate of 4.25% per year to the liabilities at the beginning of the period.

  The interest addition for the current service cost and the payments from the accounts should be prorated to recognize investment for half the period, on average.
- Add employer contributions at the rate of 139.8% of the employee contributions required to be made for the period.
- Deduct the actual employer pension and benefit payments made to the Fund for the period.

9. ACCOUNTING FOR PENSION OBLIGATIONS

Pursuant to the Agreement in principle between Manitoba Hydro and the Unions (the Agreement), the previously established pension fund known as the Manitoba Hydro Pension Fund (MHPF) is to be used solely for the benefit of retired, current and future employees of Manitoba Hydro who are participants in the CSSF and those former employees entitled to deferred pensions.

The dedication of future surpluses as a benefit for employees and former employees will impact the determination of Manitoba Hydro's pension expense.

The pension expense for a period is normally equal to the following components:

(a) current service cost,

(b) plus interest on accrued benefit obligations,

(c) less expected interest on assets,

(d) plus amount of past service cost,

(e) plus amount of actuarial gains/losses,

(f) plus amount of transitional asset/obligations.

There will be a transitioning period as Manitoba Hydro moves from its previously existing method of determining the pension expense to the CSSF Approach and the associated Pension Liabilities under the MHPF. This process commenced with the 2007 pension expense report.

10. ACTUARIAL OPINION

In our opinion, for the purposes of this Report:

- The membership data are sufficient and reliable.
- The assumptions which have been used, in aggregate, are appropriate for the purpose of determining the accounting requirements of the Plan on a going concern basis.
- The method which has been used is appropriate for the purpose of determining the accounting requirements of the Plan on a going concern basis.
- We are not aware of any other matters or events occurring since the completion of this Report, which will materially affect the calculation of the liabilities as at December 31, 2012.
- This Report has been prepared and our opinion given in accordance with accepted actuarial practice in Canada.

Respectfully submitted,

ELLEMENT & ELLEMENT

Dennis Ellement

Dennis Ellement, F.S.A., F.C.I.A.
Winnipeg, Manitoba May 29, 2013

Brandon Ellement

Brandon Ellement, A.S.A., A.C.I.A.

APPENDIX I

Reconciliation of Membership

	ACTIVES	DEFERREDS	RECIPROCALS	PENSIONERS	SURVIVORS
OPEN 31-Dec-2011	5,875	218	11	2,394	557
ACTIVE (New)	354	-	-	-	-
DEFERRED (Termination)	(30)	30	-	-	-
RECIPROCAL (Transfer)	-	-	-	-	-
PENSIONER (Retirement)	(128)	(10)	-	139	(1)
SURVIVOR (Death)	(2)	-	-	(30)	32
LUMPSUM (Termination)	(61)	(11)		(14)	(25)
CLOSE 31-Dec-2012	6,008	227	11	2,489	563

Actives

ACTIVES - MALES 31-DEC-2012

		Average			Number of Members in Each Years of Service Cell								
Age	Count	Age	Service	Salary	00 - 04	05 - 09	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 - 39	> 40
15 - 19	8	21.54	0.50	38,760	8	-	-	-	-	-	-	-	-
20 - 24	244	23.15	2.21	45,422	232	12	-	-	-	-	-	-	-
25 - 29	582	27.62	4.04	59,011	397	179	6	-	-	-	-	-	-
30 - 34	581	32.52	6.47	68,464	235	222	120	4	-	-	-	-	-
35 - 39	533	37.41	8.66	74,074	165	136	171	61	-	-	-	-	-
40 - 44	555	42.51	12.19	78,739	104	105	164	67	114	1	-	-	-
45 - 49	723	47.66	18.39	83,021	73	58	133	43	231	172	13	-	-
50 - 54	629	52.35	21.53	83,393	37	42	113	26	129	148	119	15	-
55 - 59	439	57.26	25.59	83,362	17	15	75	15	75	56	56	127	3
60 - 64	158	61.88	27.48	85,640	7	8	28	5	13	7	23	47	20
65 - 69	51	66.59	29.96	84,463	4	1	8	-	6	2	3	11	16
70 - 74	5	70.80	18.70	66,728	1	1	1	-	-	1	-	-	1
2012 Total/Avg	4,508	42.23	13.77	74,522	1,280	779	819	221	568	387	214	200	40
2011 Total/Avg	4,408	42.40	13.94	71,035	1,262	704	787	229	585	369	226	217	29

ACTIVES - FEMALES 31-DEC-2012

		Average			Number of Members in Each Years of Service Cell								
Age	Count	Age	Service	Salary	00 - 04	05 - 09	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 - 39	> 40
15 - 19	3	19.54	0.36	33,899	3	-	-	-	-	-	-	-	-
20 - 24	37	23.51	1.59	44,448	37	-	-	-	-	-	-	-	-
25 - 29	121	27.64	3.51	55,433	90	31	-	-	-	-	-	-	-
30 - 34	165	32.47	5.38	66,577	82	67	16	-	-	-	-	-	-
35 - 39	193	37.45	7.25	68,914	64	72	53	4	-	-	-	-	-
40 - 44	181	42.44	10.15	71,867	45	52	47	21	15	1	-	-	-
45 - 49	303	47.72	16.27	70,379	37	33	78	26	70	54	5	-	-
50 - 54	314	52.32	18.70	70,147	20	20	103	24	47	54	42	4	-
55 - 59	122	57.12	20.39	68,421	1	9	37	12	26	12	11	14	-
60 - 64	52	62.04	21.14	66,683	1	2	20	2	9	8	3	3	4
65 - 69	9	67.25	21.30	51,809	-	-	3	-	4	1	-	-	1
70 - 74	-	-	-	-	-	-	-	-	-	-	-	-	-
2012 Total/Avg	1,500	44.15	12.79	67,586	380	286	357	89	171	130	61	21	5
2011 Total/Avg	1,467	44.02	12.66	64,847	367	299	320	111	177	114	59	16	4

- **Deferred Pensioners**

DEFERREDS- MALES 31-DEC-2012

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
15 - 19	-	-	-	-
20 - 24	1	$ 360.89	-	-
25 - 29	7	418.28	-	-
30 - 34	17	309.02	-	-
35 - 39	7	573.39	-	-
40 - 44	24	706.03	-	-
45 - 49	39	783.11	-	-
50 - 54	36	784.25	-	-
55 - 59	12	418.22	-	-
60 - 64	8	387.62	-	-
65 - 69	2	323.11	-	-
70 - 74	-	-	-	-
2012 Total/Avg	153	$ 634.25	-	-
2011 Total/Avg	146	$ 570.45	-	-

DEFERREDS- FEMALES 31-DEC-2012

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
15 - 19	-	-	-	-
20 - 24	1	$ 105.27	-	-
25 - 29	-	-	-	-
30 - 34	5	258.19	-	-
35 - 39	9	292.68	-	-
40 - 44	14	732.44	-	-
45 - 49	20	388.04	-	-
50 - 54	17	756.09	-	-
55 - 59	5	916.71	-	-
60 - 64	3	125.62	-	-
65 - 69	-	-	-	-
70 - 74	-	-	-	-
2012 Total/Avg	74	$ 538.64	-	-
2011 Total/Avg	72	$ 420.73	-	-

▪ Pensions in Payment

PENSIONERS - MALES 31-DEC-2012

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
40 - 44	-	-	-	-
45 - 49	-	-	-	-
50 - 54	3	$ 1,607.84	2	$ 20.33
55 - 59	267	3,243.66	177	95.66
60 - 64	498	2,936.33	436	171.54
65 - 69	494	2,520.31	468	229.82
70 - 74	330	2,235.11	328	294.03
75 - 79	250	1,683.82	245	359.94
80 - 84	160	1,592.04	160	444.80
85 - 89	95	1,142.34	95	359.65
90 - 94	38	935.96	38	534.33
95 - 99	6		6	377.74
2012 Total/Avg	2,141	$ 2,400.29	1,955	$ 372.26
2011 Total/Avg	2,092	$ 2,310.28	1,910	$ 358.30

PENSIONERS - FEMALES 31-DEC-2012

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
40 - 44	-	-	-	-
45 - 49	2	$ 631.91	2	$ 0.03
50 - 54	-	-	-	-
55 - 59	67	2,359.12	42	26.27
60 - 64	93	1,853.51	75	27.55
65 - 69	75	1,274.34	68	13.71
70 - 74	54	1,092.84	52	30.66
75 - 79	20	663.03	20	73.05
80 - 84	23	803.01	23	5.37
85 - 89	10	487.37	10	7.64
90 - 94	3	414.18	3	-
95 - 99	1	485.52	1	-
2012 Total/Avg	348	$ 1,507.53	296	$ 149.79
2011 Total/Avg	302	$ 1,451.00	257	$ 144.17

Survivors in Payment

SURVIVORS - MALES 31-DEC-2012

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
40 - 44	4	$ 422.35	3	-
45 - 49	7	396.00	4	-
50 - 54	6	1,087.84	4	$ 43.06
55 - 59	1	810.68	-	-
60 - 64	4	860.19	3	-
65 - 69	4	991.97	3	0.63
70 - 74	3	362.05	2	164.21
75 - 79	3	352.78	3	-
80 - 84	2	158.51	2	-
85 - 89	2	154.03	2	-
90 - 94	1	216.50	1	-
95 - 99	-	-	-	-
>99	-	-	-	-
2012 Total/Avg	37	$ 599.83	27	$ 114.84
2011 Total/Avg	32	$ 577.34	23	$ 110.53

SURVIVORS - FEMALES 31-DEC-2012

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
40 - 44	1	$ 480.58	1	-
45 - 49	4	749.81	2	-
50 - 54	8	1,160.86	8	-
55 - 59	17	1,071.26	15	$ 14.11
60 - 64	46	1,504.11	44	29.87
65 - 69	71	1,125.61	69	64.54
70 - 74	64	918.12	61	145.45
75 - 79	82	873.63	81	79.81
80 - 84	107	640.45	106	137.94
85 - 89	77	547.06	77	26.53
90 - 94	37	386.38	37	78.37
95 - 99	11	247.65	11	106.50
>99	1	497.83	1	-
2012 Total/Avg	526	$ 833.94	513	$ 331.80
2011 Total/Avg	525	$ 802.67	512	$ 319.35

APPENDIX II

Summary of Actuarial Assumptions - Pension

		31-Dec-2012	31-Dec-2011
1.	Actuarial cost method	ABCM with salary projection	same
2.	Discount Rate for benefits		
	▪ Basic Part	4.25%	5.25%
	▪ COLA Liabilities	4.25%	5.25%
	Annual Rate of Inflation Included in Discount Rate	2.00%	same
3.	General salary increases (service and merit is separate and age specific)		
	▪ general salary increase rate for year after valuation date	0.00%	2.75%
	▪ general salary increase rate for future periods	2.75%	same
4.	Annual Salary Merit Increases	varies by age	same
5.	Indexing of Pensions (2/3 of the assumed rate of inflation)	1.33%	same
6.	Annual Increase in Earnings under Canada Pension Plan	2.75%	same
7.	Annual Increase in Maximum Pension under Income Tax Act	2013: \$2,697 Indexed ≥ 2014: 2.75%	2012: \$2,647 Indexed ≥ 2013: 2.75%
8.	Annual Rate of Interest Credited to Employee Contributions	2.25%	3.25%
9.	Employer Portion of Administrative Costs - % of employee contributions	nil	same
10.	Annual Rates of Death	UP1994 Generational Mortality using Scale AA	UP2020
11.	Proportion of Employees with a Spouse	varies by age and gender	same
12.	Annual Rates of Termination of Service	varies by age and gender	same
13.	Annual Rates of Disability	varies by age and gender	same
14.	Annual Rates of Retirement	varies by age and gender	same
15.	Reserves	24.48% of corresponding CSSF Amounts	23.89% of corresponding CSSF Amounts

APPENDIX III

Reconciliation of Change in Manitoba Hydro Accrued Pension Liabilities for 2012

Opening 31-Dec-2011 with Reserves @ 23.89%	$ 1,006,984,300
Reserves 31-Dec-2011 @ 23.89%	(49,074,100)
Opening 31-Dec-2011 without Reserves	$ 957,910,200
Interest @ 5.25%	49,938,600
Current Service cost @ 121.5% * $27,570,000	33,497,600
Employer Benefit Payments	(46,894,000)
Projected Closing 31-Dec-2012	$ 994,452,400
Experience loss/(gain) *	10,784,200
Preliminary Closing 31-Dec-2012	$ 1,005,236,600
Impact of interest from 5.25% to …	176,788,500
Impact of inflation from 2.00% to …	-
Impact of no wage growth in 2013 …	(12,901,100)
Closing 31-Dec-2012 without Reserves	$ 1,169,124,000
Closing 31-Dec-2012 with Reserves @ 24.48%	53,474,600
Closing 31-Dec-2012 with Reserves @ 24.48%	$ 1,222,598,600

* Contains a salary loss of $4,820,400 & higher than expected COLA cost on 01-Jul-2012 of $4,618,100.

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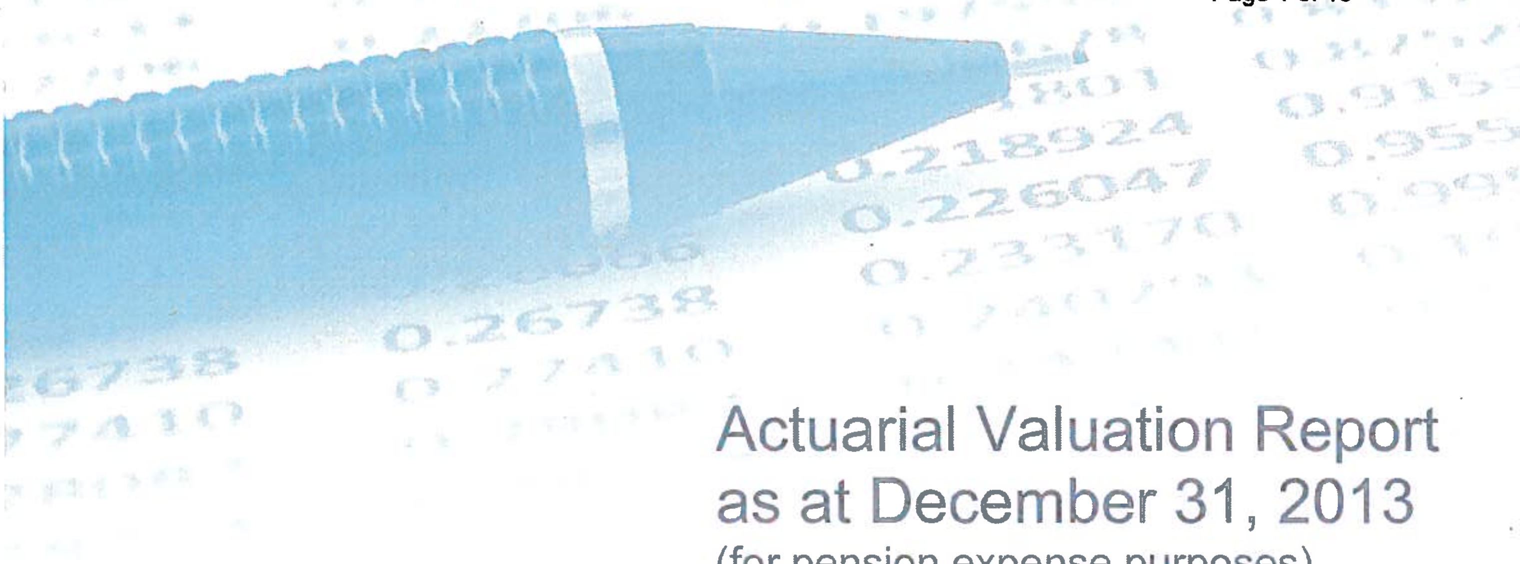

Actuarial Valuation Report as at December 31, 2013

(for pension expense purposes)

Manitoba Hydro-Electric Board Liabilities for Pension Benefits

(as a result of participation of its employees in the Civil Service Superannuation Act)

Submitted: June, 2014

Ellement

Pensions | Benefits | Investments

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APPENDICES

1. PURPOSE

The purpose of this Actuarial Valuation Report (Report) is to:

- indicate the liabilities which the Manitoba Hydro-Electric Board (Manitoba Hydro) has as at December 31, 2013 (Valuation Date), as a result of the participation of its employees in the Civil Service Superannuation Act (Superannuation Act), and

- provide a formula which can be used to estimate the increase in these liabilities in the following 12 to 18 months after December 31, 2013.

These liabilities are an estimate of the present value of the future payments which Manitoba Hydro is expected to make to the Civil Service Superannuation Fund (Fund).

The liabilities have been computed on an accounting basis. This basis contemplates the continued existence of the pension plan and the funding arrangements for the benefits under the pension plan.

The guidance for the calculation of the liabilities and the preparation of this Report are the Practice-Specific Standards for Pension Plans of the Canadian Institute of Actuaries and the International Accounting Standards Committee.

2. DATA

It is anticipated no amendments will be made to the Superannuation Act or if amendments are made, they will not affect Manitoba Hydro's pension liabilities.

The data used in the calculations includes the portion of each pension, currently in payment or which is expected to be in payment, that Manitoba Hydro is responsible for.

The data on the pensions in payment and the accrued pensionable service of employees was provided by the Civil Service Superannuation Board (Superannuation Board).

Information on the pensions and benefits paid by Manitoba Hydro and the employee contributions for 2013 were obtained from the Superannuation Board.

The data was checked for missing information, illogical information and reconciled with the prior valuation data. A few minor changes to the data resulted from the checks made.

3. MEMBERSHIP

The data provided indicated that Manitoba Hydro was the employer of record for the following participants:

	31-Dec-2013			31-Dec-2012		
	Males	Females	Total	Males	Females	Total
Actives	4,555	1,522	6,077	4,508	1,500	6,008
Deferreds	173	85	258	162	76	238
Pensioners & Survivors	2,201	945	3,146	2,178	874	3,052
Total	6,929	2,552	9,481	6,848	2,450	9,298

A reconciliation of the number of member records used in the calculations is shown in Appendix I.

The numbers shown for deferred pensioners includes 11 reciprocal transfer records at December 31, 2013 and 11 at December 31, 2012.

The numbers shown for pensioners includes 579 beneficiary records at December 31, 2013 and 563 at December 31, 2012.

4. ASSUMPTIONS

The assumptions used in this valuation and the assumptions used in the last valuation of the Manitoba Hydro pension liabilities are shown in Appendix II.

The selection of the demographic assumptions is made by the actuary. The demographic assumptions have been developed from the most current accumulated experience of the CSSF. This experience is reflected in the demographic assumptions adopted for the valuations of the CSSF. The last changes to these assumptions were made for the valuation of the CSSF as at December 31, 2012. These demographic assumptions have been adopted for this Report except for the mortality table used. The Canadian Institute of Actuaries released a new mortality table in early 2014, the Canadian Pensioner Mortality (CPM) Public Table projected using Scale B, and this table was used to value the liabilities in this Report.

The selection of the economic assumptions is made by management with consultation provided by the actuary. The economic assumptions adopted for this Report, by management have been changed from those used in the last valuation of the Manitoba Hydro pension liabilities as at December 31, 2012. In particular, the discount rate has been increased from 4.25% to 4.50% for this Report.

The selection of the assumptions is for the most part on a best estimate basis plus a small allowance for adverse deviation.

5. MANITOBA HYDRO SHARE OF BENEFIT PAYMENTS

The benefits expected to be paid are based on the provisions of the Superannuation Act.

Manitoba Hydro is expected to make payments due to:

- pensions in payment at December 31, 2013 for which Manitoba Hydro is responsible as a result of service with Manitoba Hydro,
- pensions expected to become payable to former employees who retained the right to a deferred paid-up pension, and
- pensions and other benefits expected to become payable to existing employees as a result of service completed up to the valuation date.

At present, Manitoba Hydro is contributing to the Fund based on the pay-as-you-go method of funding. Under this method, no advance funding payments for the employer share of the cost of pensions are made to the Fund. Manitoba Hydro has, however, established a separate pension fund which is being credited with interest earnings and employer contributions. It is intended that this separate fund be maintained to meet the Manitoba Hydro pension liabilities.

Each month, Manitoba Hydro makes payments to the Fund to reimburse it for:

- a portion (currently about 47%) of each pension payment to retired employees,
- a portion (currently about 47%) of each pension payment to a beneficiary of a deceased pensioner or the survivor of an employee who dies in service,
- the interest portion of any cash settlement paid to the beneficiary of an employee who dies in service,
- a portion of any amounts transferred to other pension plans under reciprocal agreements,
- a portion of any commuted values paid out as a result of employees terminating service or as a result of marriage breakdowns, and
- a portion of the administrative costs of operating the Fund in respect of Manitoba Hydro records.

Pensions in payment are indexed to 2/3 of the increases in the cost of living, provided sufficient funds exist to finance such increases. Former employees who retain a right to a deferred paid-up pension have these pensions indexed during both the deferral period and the pay-out period.

The employer share of each pension is based on when the pension starts. For pensions which commenced:

(a) prior to March 31, 1961, the employer is responsible for a portion of each increase in that pension, and
(b) after March 31, 1961, the employer is responsible for a portion (currently about 47%) of the pension paid.

The interest portion of each cash settlement is calculated by adding interest to contributions from the midpoint of the year of contribution to the date of payment to the beneficiary. Contributions made for service prior to January 1, 1984 are credited with interest at the rate of 3% per year. Contributions made for service after this date are credited with interest based on the interest rates available on 5-year fixed term deposits.

Pursuant to CSSA subsection 22(11), employer funding for employees who have service with more than one non-matching Agency shall be on a pro rata basis. This proration of the benefits assigned to an employer is based on the proration of service allocated to the employer. This proration assignment was made effective for events on or after January 1, 1998. This may decrease or increase the pension obligations in the absence of CSSA subsection 22(11). However, for enhanced benefits, it is the administrative practice to bill all of the enhanced benefits to the current employer.

6. VALUATION PROCEDURE

The accrued benefit actuarial cost method with salary projection has been used to determine the accrued liabilities and the current service cost for basic benefits applicable to each year after the valuation date. Under this method, the accrued liabilities are equal to the amount needed to fund the projected benefits accrued for service up to the valuation date. The current service cost or normal cost is equal to the estimated cost of projected benefits expected to accrue for service in the year following the valuation date.

The accrued liabilities for prior indexing adjustments are financed by a portion of the accrued assets in the COLA Account. The excess of the accrued assets plus future contributions at 10.2% of employees' contributions plus special allocations from time to time plus interest are used to finance targeted indexing adjustments of 2/3 of inflation. For this Report, all excess assets over accrued liabilities are held as a future obligation of the COLA Account. In addition, we have included an amount equal to 10.2% of employees' contributions as the indexing current service cost included in the total current service cost.

7. VALUATION RESULTS

The following table shows the accrued liabilities which Manitoba Hydro has at December 31, 2013 and December 31, 2012 as a result of the participation of its employees and former employees in the Superannuation Act:

	31-Dec-2013			31-Dec-2012		
	BASIC	COLA	TOTAL	BASIC	COLA	TOTAL
Actives	$ 632,777,900	$ -	$ 632,777,900	$ 635,854,400	$ -	$ 635,854,400
Deferreds	9,629,100	-	9,629,100	7,155,600	-	7,155,600
Pensioners & Survivors	502,489,800	61,003,900	563,493,700	466,024,300	60,089,700	526,114,000
Reserves						
- asset smoothing	-	-	-	-	-	-
- strenghtening assumptions	-	-	-	-	-	-
- adverse experience	-	-	-	-	-	-
- contribution deficiency	2,498,200	-	2,498,200	11,833,800	-	11,833,800
- 30 year run off - 1986	-	1,253,000	1,253,000	-	1,610,000	1,610,000
- 30 year run off - 2004	-	34,522,600	34,522,600	-	31,746,300	31,746,300
- Amount to finance future adjustments	-	11,040,800	11,040,800	-	8,284,500	8,284,500
Total	$ 1,147,395,000	$ 107,820,300	$1,255,215,300	$ 1,120,868,100	$ 101,730,500	$1,222,598,600

The expected average remaining service life (EARSL) of the employees who are contributors to the Fund as at the Valuation Date is 13 years.

8. PROJECTION FORMULA FOR LIABILITIES

The reconciliation of the change in accrued liabilities for 2013 is shown in Appendix III.

The following formula can be used to project the estimated increase in liabilities in the 12 to 18 months after the valuation date:

- Add interest at the rate of 4.50% per year to the liabilities at the beginning of the period.

  The interest addition for the current service cost and the payments from the accounts should be prorated to recognize investment for half the period, on average.
- Add employer contributions at the rate of 124.5% of the employee contributions required to be made for the period.
- Deduct the actual employer pension and benefit payments made to the Fund for the period.

9. ACCOUNTING FOR PENSION OBLIGATIONS

Pursuant to the Agreement in principle between Manitoba Hydro and the Unions (the Agreement), the previously established pension fund known as the Manitoba Hydro Pension Fund (MHPF) is to be used solely for the benefit of retired, current and future employees of Manitoba Hydro who are participants in the CSSF and those former employees entitled to deferred pensions.

The dedication of future surpluses as a benefit for employees and former employees will impact the determination of Manitoba Hydro's pension expense.

The pension expense for a period is normally equal to the following components:

(a) current service cost,

(b) plus interest on accrued benefit obligations,

(c) less expected interest on assets,

(d) plus amount of past service cost,

(e) plus amount of actuarial gains/losses,

(f) plus amount of transitional asset/obligations.

There will be a transitioning period as Manitoba Hydro moves from its previously existing method of determining the pension expense to the CSSF Approach and the associated Pension Liabilities under the MHPF. This process commenced with the 2007 pension expense report.

10. ACTUARIES' OPINION

In our opinion, for the purposes of this Report:

- The membership data are sufficient and reliable.

- The assumptions which have been used, in aggregate, are appropriate for the purpose of determining the accounting requirements of the Plan on an accounting basis.

- The method which has been used is appropriate for the purpose of determining the accounting requirements of the Plan on an accounting basis.

- We are not aware of any other matters or events occurring since the completion of this Report, which will materially affect the calculation of the liabilities as at December 31, 2013.

- This Report has been prepared and our opinion given in accordance with accepted actuarial practice in Canada.

Respectfully submitted,

ELLEMENT

Dennis Ellement, F.S.A., F.C.I.A.
Winnipeg, Manitoba June 3, 2014

Brandon Ellement, F.S.A., A.C.I.A.

APPENDIX I

Reconciliation of Membership

	ACTIVES	DEFERREDS	RECIPROCALS	PENSIONERS	SURVIVORS
OPEN 31-Dec-2012	6,008	227	11	2,489	563
ACTIVE (New)	320	-	-	-	-
DEFERRED (Termination)	(35)	35	-	-	-
RECIPROCAL (Transfer)	-	-	-	-	-
PENSIONER (Retirement)	(136)	(5)	-	145	(4)
SURVIVOR (Death)	-	(1)	-	(39)	40
LUMPSUM (Termination)	(80)	(9)		(28)	(20)
CLOSE 31-Dec-2013	6,077	247	11	2,567	579

Actives

ACTIVES - MALES 31-DEC-2013

		Average			Number of Members in Each Years of Service Cell								
Age	Count	Age	Service	Salary	00 - 04	05 - 09	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 - 39	> 40
15 - 19	14	19.34	0.54	34,511	14	-	-	-	-	-	-	-	-
20 - 24	256	23.17	2.08	45,572	236	20	-	-	-	-	-	-	-
25 - 29	555	27.70	4.30	60,709	338	208	9	-	-	-	-	-	-
30 - 34	604	32.39	6.55	70,194	214	265	120	5	-	-	-	-	-
35 - 39	593	37.42	9.11	75,462	147	181	178	87	-	-	-	-	-
40 - 44	536	42.66	12.30	79,733	97	113	128	102	93	3	-	-	-
45 - 49	665	47.72	18.28	82,967	61	68	112	58	199	160	7	-	-
50 - 54	679	52.37	21.80	84,909	38	47	126	29	119	175	126	19	-
55 - 59	419	57.25	25.04	82,863	18	19	72	23	55	68	60	97	7
60 - 64	182	61.95	27.75	85,911	8	11	25	9	16	17	16	51	29
65 - 69	49	66.85	29.24	83,114	4	1	9	1	2	4	4	9	15
70 - 74	3	70.33	30.32	70,292	-	-	-	-	2	-	-	-	1
2013 Total/Avg	4,555	42.20	13.81	75,344	1,175	933	779	314	486	427	213	176	52
2012 Total/Avg	4,508	42.23	13.77	74,522	1,280	779	819	221	568	387	214	200	40

ACTIVES - FEMALES 31-DEC-2013

		Average			Number of Members in Each Years of Service Cell								
Age	Count	Age	Service	Salary	00 - 04	05 - 09	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 - 39	> 40
15 - 19	-	-	-	-	-	-	-	-	-	-	-	-	-
20 - 24	43	23.28	1.57	44,190	42	1	-	-	-	-	-	-	-
25 - 29	129	27.70	3.34	53,935	99	29	1	-	-	-	-	-	-
30 - 34	175	32.59	5.44	68,109	82	75	18	-	-	-	-	-	-
35 - 39	186	37.55	7.68	69,371	56	64	57	9	-	-	-	-	-
40 - 44	186	42.35	9.53	73,287	42	63	49	20	12	-	-	-	-
45 - 49	266	47.74	16.01	71,854	37	31	61	26	62	48	1	-	-
50 - 54	344	52.37	19.30	69,972	17	30	100	30	47	68	51	1	-
55 - 59	126	57.05	20.25	69,747	3	7	44	8	27	16	7	13	1
60 - 64	57	62.08	22.44	65,195	1	4	17	4	10	5	7	5	4
65 - 69	10	67.94	22.26	55,190	-	-	3	-	4	2	-	-	1
70 - 74	-	-	-	-	-	-	-	-	-	-	-	-	-
2013 Total/Avg	1,522	44.19	12.88	68,036	379	304	350	97	162	139	66	19	6
2012 Total/Avg	1,500	44.15	12.79	67,586	380	286	357	89	171	130	61	21	5

▪ Deferred Pensioners

DEFERREDS- MALES 31-DEC-2013

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
15 - 19	-	$ -	-	-
20 - 24	2	1,619.80	-	-
25 - 29	14	968.04	-	-
30 - 34	14	660.01	-	-
35 - 39	11	856.65	-	-
40 - 44	22	1,030.36	-	-
45 - 49	34	643.43	-	-
50 - 54	44	541.77	-	-
55 - 59	13	210.34	-	-
60 - 64	7	371.11	-	-
65 - 69	3	447.38	-	-
70 - 74	-	-	-	-
2013 Total/Avg	164	$ 673.85	-	-
2012 Total/Avg	153	$ 634.25	-	-

DEFERREDS- FEMALES 31-DEC-2013

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
15 - 19	-	$ -	-	-
20 - 24	-	-	-	-
25 - 29	1	231.14	-	-
30 - 34	4	501.81	-	-
35 - 39	12	635.59	-	-
40 - 44	16	1,046.44	-	-
45 - 49	21	424.15	-	-
50 - 54	18	323.87	-	-
55 - 59	8	695.82	-	-
60 - 64	3	185.08	-	-
65 - 69	-	-	-	-
70 - 74	-	-	-	-
2013 Total/Avg	83	$ 571.89	-	-
2012 Total/Avg	74	$ 538.64	-	-

▪ Pensioners and Survivors in Payment

PENSIONERS & SURVIVORS - MALES 31-DEC-2013

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
35 - 39	-	$ -	-	$ -
40 - 44	-	-	-	-
45 - 49	1	480.74	1	38.00
50 - 54	4	447.90	3	43.70
55 - 59	251	3,210.16	184	68.15
60 - 64	473	3,109.12	429	163.32
65 - 69	548	2,636.35	524	292.44
70 - 74	346	2,290.31	337	434.14
75 - 79	259	1,786.50	254	559.94
80 - 84	174	1,613.90	174	644.14
85 - 89	106	1,124.67	106	642.80
90 - 94	33	1,063.87	33	754.35
95 - 99	6	330.00	6	332.18
>99	-	-	-	-
2013 Total/Avg	2,201	$ 2,460.53	2,051	$ 356.73
2012 Total/Avg	2,178	$ 2,369.70	1,982	$ 368.75

PENSIONERS & SURVIVORS - FEMALES 31-DEC-2013

Age	Count	Average Monthly Basic Pension	Count	Average Monthly Cola Pension
35 - 39	1	$ 167.10	-	$ -
40 - 44	2	628.12	1	64.04
45 - 49	7	481.18	4	53.43
50 - 54	10	628.00	7	63.32
55 - 59	90	2,157.92	58	50.82
60 - 64	127	1,892.76	112	90.17
65 - 69	140	1,440.86	134	160.10
70 - 74	128	1,103.57	122	243.16
75 - 79	79	895.04	77	294.77
80 - 84	119	874.13	118	376.65
85 - 89	100	738.83	100	414.89
90 - 94	97	468.48	97	381.46
95 - 99	39	281.25	39	328.73
>99	6	312.62	6	490.59
2013 Total/Avg	945	$ 1,159.30	875	$ 258.61
2012 Total/Avg	874	$ 1,102.14	809	$ 265.21

APPENDIX II

Summary of Actuarial Assumptions - Pension

		31-Dec-2013	31-Dec-2012
1.	Actuarial cost method	ABCM with salary projection	same
2.	Discount Rate for benefits		
	▪ Basic Part	4.50%	4.25%
	▪ COLA Liabilities	4.50%	4.25%
	Annual Rate of Inflation Included in Discount Rate	2.00%	same
3.	General salary increases (service and merit is separate and age specific)		
	▪ general salary increase rate for the year after the valuation date	2.75%	0.00%
	▪ general salary increase rate for the second year after the valuation date	2.75%	same
	▪ general salary increase rate for future periods	2.50%	2.75%
4.	Annual Salary Merit Increases	varies by age	same
5.	Indexing of Pensions (2/3 of the assumed rate of inflation)	1.33%	same
6.	Annual Increase in Earnings under Canada Pension Plan	2.75%	same
7.	Annual Increase in Maximum Pension under Income Tax Act	2014: $2,770 Indexed ≥ 2015: 2.75%	2013: $2,697 Indexed ≥ 2014: 2.75%
8.	Annual Rate of Interest Credited to Employee Contributions	2.50%	2.25%
9.	Employer Portion of Administrative Costs - % of employee contributions	nil	same
10.	Annual Rates of Death	CPM Public Mortality projected using Scale B	UP1994 Generational Mortality using Scale AA
11.	Proportion of Employees with a Spouse	varies by age and gender	same
12.	Annual Rates of Termination of Service	varies by age and gender	same
13.	Annual Rates of Disability	varies by age and gender	same
14.	Annual Rates of Retirement	varies by age and gender	same
15.	Reserves	24.44% of corresponding CSSF Amounts	24.48% of corresponding CSSF Amounts

APPENDIX III

Reconciliation of Change in Manitoba Hydro Accrued Pension Liabilities for 2013

Opening 31-Dec-2012 with Reserves @ 24.48%	$ 1,222,598,600
Reserves 31-Dec-2012 @ 24.48%	(53,474,600)
Opening 31-Dec-2012 without Reserves	$ 1,169,124,000
Interest @ 4.25%	49,648,700
Current Service cost @ 139.8% * $31,338,000	43,810,500
Employer Benefit Payments	(45,648,000)
Projected Closing 31-Dec-2013	$ 1,216,935,200
Experience loss/(gain)	2,346,700
Preliminary Closing 31-Dec-2013	$ 1,219,281,900
Impact of mortality CPM PUB 2014 PROJB	47,814,900
Impact of interest from 4.25% to …	(48,201,800)
Impact of wage growth from 2.75% to …	(12,994,300)
Impact of inflation from 2.00% to …(see wage)	-
Closing 31-Dec-2013 without Reserves	$ 1,205,900,700
Reserves 31-Dec-2013 @ 24.44%	49,314,600
Closing 31-Dec-2013 with Reserves @ 24.44%	$ 1,255,215,300

Benefit security at a reasonable cost

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Pensions | Benefits | Investments

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Section:	Tab 5	**Page No.:**	
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expenses		
Issue:	EFT Staffing		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file an update to PUB/MH I-64 from the 2012 GRA for the years 2008/09 to 2014/15, including identifying specifically the increases in staffing levels for Conawapa.

RATIONALE FOR QUESTION:

MH has indicated that staffing reductions will be made as part of its cost containment strategy.

RESPONSE:

The attached schedules show total EFT (straight time and overtime) changes from 2008/09 to 2014/15 by business unit. Fiscal year comparisons from 2008/09 to 2011/12 are shown as filed in the last GRA (PUB/MH I 64e) and reflect the previous organizational structure. Fiscal year comparisons from 2011/12 to 2014/15 are presented in the current organizational structure.

The number of total EFTs (straight time and overtime) working on Conawapa from 2008/09 to 2014/15 has decreased from 40 to 35 as shown in the table below. EFTs are calculated based upon hours charged to the Conawapa Generation project by staff throughout the Corporation, utilizing their respective activity rates.

Prior to the suspension of the Conawapa Generation project, activities engaged in by the Corporation included the Needs For and Alternatives To (NFAT) hearing, environmental assessments, and studies in preparation of the Environmental Impact Statement, negotiations with First Nations, Aboriginal Traditional Knowledge studies and engineering design.

The number of EFTs significantly decreases following the August 2014 decision to suspend construction activities. Please refer to PUB/MH I-35b for a summary of EFTs forecast to work on Conawapa in 2015/16 and 2016/17. In addition, MIPUG/MH I-10a provides a description of the activities engaged in by the Corporation in the forecast periods.

MANITOBA HYDRO
CONAWAPA TOTAL EFTS

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast
General Counsel & Corporate Secretary	0	0	0	0	0	2	1
Corporate Relations	0	0	0	0	1	1	0
Finance & Regulatory	0	0	0	0	1	3	1
Generation Operations	12	15	11	12	15	24	10
Major Capital Projects	20	20	19	22	25	34	23
Transmission	8	8	7	4	2	2	0
Customer Care & Energy Conservation	0	0	0	0	0	4	0
Business Unit Total	**40**	**43**	**37**	**38**	**44**	**70**	**35**

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2008/09 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2009/10 Actual	Comments Regarding New Positions
President & CEO						
General Counsel	26			3	29	
Public Affairs	32			2	34	
Research & Development	2				2	
Administration	27	2	1		29	One vice-president & one division manager.
Corporate Planning and Strategic Review	20	1	3	(2)	22	Position for administrative support.
	107	3	4	3	116	
Corporate Relations						
Aboriginal Relations	67			1	68	
Administration	8		(4)	1	5	
	75	-	(4)	2	73	
Finance & Administration						
Information Technology Services	313				313	
Treasury	16			(1)	14	
Corporate Risk Management	5				5	
Gas Supply	20				20	
Rates & Regulatory Affairs	19			1	20	
Corporate Controller	107	2	4		113	Positions for IFRS project.
Human Resources	138		(5)	(3)	129	
Corporate Safety & Health	61			(4)	57	
Corporate Services	311		7	2	321	
Administration	18				18	
	1,006	2	6	(5)	1,010	

	2008/09 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2009/10 Actual	Comments Regarding New Positions
Power Supply						
Power Planning	58	7		1	66	Positions mainly for Water Resource, Energy Policy & Emissions Trading.
Power Projects Development	44			3	47	
Portfolio Projects Management	5				4	
HVDC	250			4	254	
Generation North	219			5	224	
Generation South	459	3		9	471	Positions for Ice Safety Management.
Power Sales & Operations	84			(2)	82	
Engineering Services	183	14		17	214	Positions mainly for major capital projects (Keeyask & Conawapa)
New Generation Construction	83	25			108	Positions mainly for major capital projects (Keeyask, Conawapa, Pointe du Bois, Bipole 3)
Administration	191	17			208	Positions for the Operating Technician Trainee Program
	1,576	66	-	37	1,679	
Transmission						
Transmission System Operations	362		1	1	364	
Transmission Planning & Design	191	7	(1)	9	206	Positions to support Wuskwatim and Riel Station projects.
Transmission Construction & Line Maintenance	276	4		12	292	Positions to support Wuskwatim and Riel Station projects.
Apparatus Maintenance	420			10	431	
Administration	49	6	(3)	(2)	50	Positions for Engineer-in-Training program.
	1,298	17	(3)	30	1,342	

		2008/09 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2009/10 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**						
53	Customer Service Operations - Winnipeg & North	530	3	(7)	1	528	Positions related to Special Northern Collections Initiative.
54	Customer Service Operations - South	566	1	8	2	577	Position for administrative support.
55	Distribution Engineering & Construction Rural	284		(1)	2	277	
56	Distribution Engineering & Construction Winnipeg	291		(1)	(6)	288	
57	Administration	1	2	3		7	Positions for administrative support.
58		1,671	6	2	(1)	1,678	
59							
60	**Customer Care & Marketing**						
61	Industrial & Commercial Solutions	54			3	57	
62	Consumer Marketing & Sales	216		(7)	(2)	207	
63	Business Support Services	228	2	(1)	(7)	222	Positions for quality assessment and collections function.
64	Administration	44		3	(1)	46	
65		543	2	(5)	(7)	532	
66							
67	**Total**	6,276	96	-	59	6,429	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2009/10 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2010/11 Actual	Comments Regarding New Positions
President & CEO						
General Counsel	29	2			31	Positions for Corporate Security function.
Public Affairs	34			(1)	33	
Research & Development	2		(1)	(0)	1	
Administration	29		2	1	32	
Corporate Planning and Strategic Review	22	6	1	(2)	27	Positions to support corporate strategic review, corporate planning, economic development and corporate environmental management.
	116	8	2	(2)	123	
Corporate Relations						
Aboriginal Relations	68			(3)	65	
Administration	5		(1)	-	4	
	73	-	(1)	(3)	69	
Finance & Administration						
Information Technology Services	313			1	314	
Treasury	14			(1)	13	
Corporate Risk Management	5	1		(1)	6	Position for business analysis function.
Gas Supply	20			1	21	
Rates & Regulatory Affairs	20			2	22	
Corporate Controller	113		2	(4)	110	
Human Resources	129		(1)	(1)	127	
Corporate Safety & Health	57			(0)	57	
Corporate Services	321			4	325	
Administration	18			(2)	16	
	1,010	1	-	(2)	1,009	

		2009/10 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2010/11 Actual	Comments Regarding New Positions
31	**Power Supply**						
32	Power Planning	66	4	1	4	75	Positions to support the growing environmental management and emerging energy issues within Power Supply.
33	Power Projects Development	47	2	(1)		48	Positions to support hydro power planning and assessments and licensing functions.
34	Portfolio Projects Management	4	1		1	6	Position to support Hydro's sustainable generation options.
35	HVDC	254			6	260	
36	Generation North	224			10	235	
37	Generation South	471	5		12	488	Positions for Ice Safety Management for the Winnipeg River.
38	Power Sales & Operations	82			4	86	
39	Engineering Services	214	16		3	233	Positions for Field Inspection work and to provide support in major projects such as Great Falls Unit #4 Overhaul and Physical Security Upgrades, as well as new generation projects such as Kettle Unit 1-4 Stator Replacement.
40	New Generation Construction	108	13		3	124	Positions to support new generation projects such as Wuskwatim, Conawapa, Keeyask, and Bipole III.
41	Administration	208	28		7	243	Positions for the Operating Technician Trainee Program
42		1,679	69	-	49	1,796	
43							
44	**Transmission**						
45	Transmission System Operations	364			1	365	
46	Transmission Planning & Design	206	4	(2)	6	214	Positions to support the environmental function for BPIII and to support the commissioning function for various northern projects.
47	Transmission Construction & Line Maintenance	292	6		5	303	Positions to support Riel Station and BPIII.
48	Apparatus Maintenance	431			3	434	
49	Administration	50			(2)	48	
50		1,342	10	(2)	13	1,365	
51							

		2009/10 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2010/11 Actual	Comments Regarding New Positions
52	**Customer Services & Distribution**						
53	Customer Service Operations - Winnipeg & North	528	8	1	(6)	532	Positions to support repatriation of Line Locate function from MHUS
54	Customer Service Operations - South	577			3	580	
55	Distribution Engineering & Construction Rural	277			11	288	
56	Distribution Engineering & Construction Winnipeg	288	2	2	6	298	Positions to support fleet, environmental and engineering functions.
57	Administration	7			(1)	6	
58		1,678	10	3	14	1,704	
59							
60	**Customer Care & Marketing**						
61	Industrial & Commercial Solutions	57			(3)	54	
62	Consumer Marketing & Sales	207			3	210	
63	Business Support Services	222		(2)	(4)	217	
64	Administration	46			1	47	
65		532	-	(2)	(2)	528	
66							
67	**Total**	6,429	99	-	67	6,594	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2010/11 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2011/12 Actual	Comments Regarding New Positions
President & CEO						
General Counsel	31			2	32	
Public Affairs	33				33	
Research & Development	1				1	
Administration	32		1		32	
Corporate Planning & Strategic Review	27	2	(1)	-	29	Positions to support administrative function.
	123	2	-	2	127	
Corporate Relations						
Aboriginal Relations	65			1	66	
Administration	4			(1)	3	
	69	-	-	-	69	
Finance & Administration						
Information Technology Services	314			(2)	312	
Treasury	13			(0)	13	
Corporate Risk Management	6			1	6	
Gas Supply	21			(1)	20	
Rates & Regulatory Affairs	22			(1)	21	
Corporate Controller	110			(6)	104	
Human Resources	127			(0)	126	
Corporate Safety & Health	57			(2)	55	
Corporate Services	325			(12)	313	
Administration	16			(3)	13	
	1,009	-	-	(27)	983	

		2010/11 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2011/12 Actual	Comments Regarding New Positions
32	**Power Supply**						
33	Power Planning	75			3	78	
34	Power Projects Development	48	5		1	53	Positions mainly to support major capital projects such as Keeyask, Conawapa and Pointe du Bois capital projects.
35	Portfolio Projects Management	6	3	1	(1)	9	Positions to support regulatory reviews of Hydro's major projects and associated environmental processes.
36	HVDC	260	1		(3)	258	Positions hired later in year to support BipoleIII (translates to 1 EFT).
37	Generation North	235	3	4	8	249	Positions to support the upcoming in-service for Wuskwatim and the operations of the Kettle generating station.
38	Generation South	488			1	489	
39	Power Sales & Operations	86			2	88	
40	Engineering Services	233	6	(6)	6	239	Positions to support engineering field investigations and engineering design functions.
41	New Generation Construction	124	15	2	(4)	137	Positions to support various capital projects such as Pointe Du Bois, BPIII and, Keeyask.
42	Administration	243	12			255	Positions for the Operating Technician Trainee Program.
43		1,796	45	-	12	1,853	
44							
45	**Transmission**						
46	Transmission System Operations	365			(9)	356	
47	Transmission Planning & Design	214	1		18	233	Position for Station Standards Project.
48	Transmission Construction & Line Maintenance	303	2		(5)	301	Positions to support Bipole III project.
49	Apparatus Maintenance	434			(6)	428	
50	Administration	48			(12)	36	
51		1,365	4	-	(15)	1,354	
52							

		2010/11 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2011/12 Actual	Comments Regarding New Positions
53	**Customer Services & Distribution**						
54	Customer Service Operations - Winnipeg & North	532		(13)	(11)	508	
55	Customer Service Operations - South	580			(19)	562	
56	Distribution Engineering & Construction Rural	288	4		17	309	Positions to support MTS Fibre to Home program.
57	Distribution Engineering & Construction Winnipeg	298		(7)	5	296	
58	Administration	6		20	1	27	
59		1,704	4	-	(7)	1,701	
60							
61	**Customer Care & Marketing**						
62	Industrial & Commercial Solutions	54		1	(2)	52	
63	Consumer Marketing & Sales	210		(1)	(10)	199	
64	Business Support Services	217	1		2	220	Position for Meter Compliance project.
65	Administration	47			2	49	
66		528	1	-	(8)	521	
67							
68	**Total**	6,594	55	-	(42)	6,608	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

	2011/12 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2012/13 Actual	Comments Regarding New Positions
President & CEO						
President & CEO Administration	19		(1)	(1)	19	
Public Affairs	32				31	
	51	-	(1)	(1)	49	
General Counsel & Corporate Secretary						
Law Division	19			1	20	
Internal Audit Division	13			(2)	11	
Administration	8			1	9	
	40	-	-	-	40	
Human Resources & Corporate Services						
Information Technology Services	313			(9)	304	
Human Resources	150		1	(1)	150	
Workplace Safety & Health and Corp Serv	349		2	1	352	
Corporate Environmental Management	5	-	(2)	2	5	
Administration	11		(1)	(1)	10	
	829	-	-	(7)	822	
Corporate Relations						
Aboriginal Relations	66			1	67	
Corporate Planning & Strategic Review	22		1	(3)	18	
Administration	3		(1)	1	3	
	91	-	(1)	(1)	88	
Finance & Regulatory						
Treasury	13	1		-	14	Position for administrative support.
Corporate Risk Mgmt Department	6		1	(1)	6	
Rates & Regulatory Affairs	21			(1)	20	
Corporate Controller	93			3	96	
Administration	12			1	13	
	146	1	1	2	149	

	2011/12 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2012/13 Actual	Comments Regarding New Positions
38 **Generation Operations**						
39 Power Planning	82	3	(3)	1	83	Positions for resource planning, energy policy and NFAT coordination.
40 Generation North	226	16		(17)	225	Positions for Wuskwatim operations and Kettle camp operations.
41 Generation South	430	2		(7)	425	Positions for Grand Rapids Fish Hatchery operations.
42 Engineering Services	318	1		1	320	Positions for capital project management and engineering functions and accreditation of High Voltage Test Facility.
43 Power Sales & Operations	88			(1)	87	
44 Administration	24			(1)	23	
45	1,166	22	(3)	(23)	1,164	
46						
47 **Major Capital Projects**						
48 Licensing & Relationship Management Div	53	2	(1)	2	56	Positions for hydro power planning and major project partnership functions.
49 Portfolio Projects Management	9	1	1	2	12	Positions for sturgeon stewardship coordination and project management support.
50 Bipole III Project	9	8			17	Positions to perform engineering and project management functions.
51 New Generation Construction	92	16		(8)	100	Positions for engineering and technical functions for new generation projects such as Pointe Du Bois Spillway and Keeyask.
52 Administration	35	5			40	Positions for project management and technical functions to support new generation projects, primarily Keeyask and Pointe Du Bois Spillway.
53	198	32	-	(5)	225	
54						
55 **Transmission**						
56 HVDC	258	7		(2)	263	Positions to support Bipole III project for technical and project management functions.
57 Transmission System Operations	356			1	357	
58 Transmission Planning & Design	233	3		1	237	Positions for environmental and project management functions.
59 Transmission Construction & Line Mtce	301	2	1	1	305	Positions to support Bipole III project and coordination functions.
60 Apparatus Maintenance	427			(6)	420	
61 Administration	267	23		5	296	Positions for the Operating Technician Trainee Program.
62	1,841	35	1	-	1,878	
63						

	2011/12 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2012/13 Actual	Comments Regarding New Positions
64 **Customer Service & Distribution**						
65 Distribution Eng & Construction Division	554	-	1	6	560	
66 Customer Service Operations - Wpg&North	508	5	(2)	(2)	509	Positions to support meter changes required to meet new Measurement Canada standards.
67 Customer Service Operations - South	551	8	(2)	7	564	Positions to support meter exchange program and customer growth in southern Manitoba.
68 Business Support & Capital Asset Mgmt	114		2	6	122	
69 Administration	7			(1)	6	
70	1,734	13	(1)	16	1,760	
71						
72 **Customer Care & Energy Conservation**						
73 Gas Supply	20				20	
74 Industrial & Commercial Solutions	55		2	1	58	
75 Consumer Marketing & Sales	199		1	(6)	194	
76 Business Support Services	189			(3)	186	
77 Administration	49			(4)	45	
78	512	-	3	(12)	503	
79						
80						
81 Total	6,608	103	(1)	(31)	6,678	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

1					**Overtime,**		**Comments Regarding New Positions**
2		**2012/13**	**New**		**Vacancies &**	**2013/14**	
3		**Actual**	**Positions**	**Transfers**	**Other**	**Actual**	
4							
5	**President & CEO**						
6	President & CEO Administration	19		(4)		14	
7	Public Affairs	31		(2)	(2)	29	
8		49	-	(5)	(2)	43	
9							
10	**General Counsel & Corporate Secretary**						
12	Law Division	20		(2)	1	19	
13	Internal Audit Division	11			1	13	
11	Administration	9		3	1	13	
14		40	-	2	3	44	
15							
16	**Human Resources & Corporate Services**						
18	Information Technology Services	304		1	1	306	
19	Human Resources	150		1	(1)	150	
20	Workplace Safety & Health and Corp Serv	352		8	2	362	
21	Corporate Environmental Management	5		(1)		5	
17	Administration	10		(5)		5	
22		822	-	3	3	828	
23							
24	**Corporate Relations**						
25	Aboriginal Relations	67			(1)	65	
27	Corporate Planning & Strategic Review	18		-	(2)	16	
26	Administration	3		1		5	
28		88	-	1	(4)	86	
29							
30	**Finance & Regulatory**						
31	Treasury	14			(1)	13	
32	Corporate Risk Mgmt Department	6				6	
33	Rates & Regulatory Affairs	20			1	21	
34	Corporate Controller	96			(3)	93	
36	Administration	13		5	1	19	
37		149	-	5	(2)	151	
38							

		2012/13 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2013/14 Actual	Comments Regarding New Positions
39	**Generation Operations**						
41	Power Planning	83	2			86	Positions for Grand Rapids Fish Hatchery operations and environmental analysis activities.
42	Generation North	225	9			233	Positions mainly for Wuskwatim operations.
43	Generation South	425	5		(5)	425	Positions mainly for Grand Rapids Fish Hatchery operations.
44	Engineering Services	320	7	(1)	10	336	Positions for project management activities and Enterprise Asset Management (EAM) project.
45	Power Sales & Operations	87	3	2	4	96	Positions for resource management and power marketing activities.
40	Administration	23		(2)	(2)	20	
46		1,164	25	(1)	8	1,196	
47							
48	**Major Capital Projects**						
49	Licensing & Relationship Management Div	56	5		(1)	60	Positions for new generation licensing and partnership planning activities.
50	Portfolio Projects Management	12	2		3	17	Positions for coordinating activities in sturgeon stewardship and project management function for Keeyask/Conawapa.
51	Bipole III Project	17	8		7	32	Positions for construction activities, engineering function and project management support.
53	New Generation Construction	100	24		(20)	104	Positions for engineering and support functions for new generation projects such as Pointe Du Bois Spillway, Keeyask and Conawapa.
52	Administration	40	1	2		43	Positions for management and administrative support.
55		225	40	2	(11)	256	
56							
57	**Transmission**						
58	HVDC	263			(4)	259	
60	Transmission System Operations	357			5	362	
61	Transmission Planning & Design	237	3		8	248	Positions for commissioning activities.
62	Transmission Construction & Line Mtce	305	9	(2)	10	321	Positions to support Bipole III project.
63	Apparatus Maintenance	420			(11)	409	
59	Administration	296	5	1	2	303	Positions for the Operating Technician Trainee program.
64		1,878	17	(2)	11	1,904	
65							

		2012/13 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2013/14 Actual	Comments Regarding New Positions
66	**Customer Service & Distribution**						
67	Distribution Eng & Construction Division	560	2		(2)	559	Positions for administrative support.
68	Customer Service Operations - Wpg&North	509		(6)	(14)	489	
69	Customer Service Operations - South	564	14	(4)	(23)	550	Technical positions for customer growth in southwestern Manitoba as well as positions for an additional Line Trades Training (LTT) crew.
70	Business Support & Capital Asset Mgmt	122	1	4	5	132	Position for capital and risk management.
71	Administration	6				6	
72		1,760	16	(6)	(33)	1,737	
73							
74	**Customer Care & Energy Conservation**						
75	Gas Supply	20		1	(1)	20	
77	Industrial & Commercial Solutions	58			2	60	
78	Consumer Marketing & Sales	194			8	202	
79	Business Support Services	186			(1)	185	
76	Administration	45			(2)	43	
80		503	-	1	7	511	
81							
82							
83	**Total**	6,678	98	(1)	(20)	6,756	

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY DIVISION

1-3		2013/14 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2014/15 Forecast	Comments Regarding New Positions
4							
5	**President & CEO**						
6	President & CEO Administration	14			1	15	
7	Public Affairs	29		(5)	3	27	
8		43	-	(5)	4	42	
9							
10	**General Counsel & Corporate Secretary**						
12	Law Division	19		(1)	2	20	
13	Internal Audit Division	13				13	
11	Administration	13				13	
14		44	-	(1)	2	45	
15							
16	**Human Resources & Corporate Services**						
18	Information Technology Services	306		5	(1)	310	
19	Human Resources	150		(2)	(5)	143	
20	Workplace Safety & Health and Corp Serv	362		6	16	384	
21	Corporate Environmental Management	5			(1)	4	
17	Administration	5				5	
22		828	-	9	9	846	
23							
24	**Corporate Relations**						
25	Aboriginal Relations	65		(1)	6	71	
27	Corporate Planning & Strategic Review	16			1	16	
26	Administration	5		1		6	
28		86	-	-	7	93	
29							
30	**Finance & Regulatory**						
31	Treasury	13				13	
32	Corporate Risk Mgmt Department	6			1	7	
33	Rates & Regulatory Affairs	21			2	23	
34	Corporate Controller	93		(2)	(1)	90	
36	Administration	19		1		20	
37		151	-	(1)	2	152	
38							

		2013/14 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2014/15 Forecast	Comments Regarding New Positions
39	**Generation Operations**						
41	Power Planning	86			(6)	80	
42	Generation North	233			(1)	232	
43	Generation South	425			(21)	405	
44	Engineering Services	336		(4)	15	347	
45	Power Sales & Operations	96	1		1	99	Position to support the Great Northern Transmission Line project.
40	Administration	20		(2)	1	18	
46		1,196	1	(6)	(10)	1,180	
47							
48	**Major Capital Projects**						
49	Licensing & Relationship Management Div	60			(3)	58	
50	Portfolio Projects Management	17			(2)	15	
51	Bipole III Project	32	19	1	8	60	Positions for construction activities, engineering function and project management support for Bipole III.
53	New Generation Construction	104	10	(2)	2	115	Positions for engineering and constructions activities for new generation projects such as Pointe Du Bois Spillway, Keeyask and Conawapa.
52	Administration	43	5	3	5	56	Positions for management, administrative support and project accounting and scheduling functions.
55		256	34	2	11	304	
56							
57	**Transmission**						
58	HVDC	259			10	269	
60	Transmission System Operations	362			(6)	357	
61	Transmission Planning & Design	248		1	(0)	249	
62	Transmission Construction & Line Mtce	321	17	(3)	4	340	Positions to support Bipole III project.
63	Apparatus Maintenance	409			9	418	
59	Administration	303		1	(22)	281	
64		1,904	17	(1)	(5)	1,914	
65							

		2013/14 Actual	New Positions	Transfers	Overtime, Vacancies & Other	2014/15 Forecast	Comments Regarding New Positions
66	**Customer Service & Distribution**						
67	Distribution Eng & Construction Division	559			9	568	
68	Customer Service Operations - Wpg&North	489			22	510	
69	Customer Service Operations - South	550			(1)	550	
70	Business Support & Capital Asset Mgmt	132		3	(5)	130	
71	Administration	6			(1)	5	
72		1,737	-	3	25	1,764	
73							
74	**Customer Care & Energy Conservation**						
75	Gas Supply	20				20	
77	Industrial & Commercial Solutions	60	5			65	Positions for engineering analysis activites for DSM.
78	Consumer Marketing & Sales	202	2		2	206	Positions for engineering analysis activites for DSM.
79	Business Support Services	185			7	192	
76	Administration	43			(1)	43	
80		511	6	-	8	524	
81							
82							
83	**Total**	6,756	59	-	48	6,864	

Section:	Tab 5 Appendix 5.5	Page No.:	Figure 5.5.5
Topic:	Financial Results & Forecasts		
Subtopic:	Accounting Changes		
Issue:	Impact of accounting changes on revenue requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file an update to PUB/MH I-9 d (2012 GRA) based on IFF14.

RATIONALE FOR QUESTION:

Review forecast changes to OM&A excluding the impacts related to IFRS.

RESPONSE:

Please see the response to PUB/MH-I-31b which compares MH14 to MH12.

Section:	Tab 5 Appendix 5.5	**Page No.:**	Figure 5.5.5
Topic:	Financial Results & Forecasts		
Subtopic:	Accounting Changes		
Issue:	Impact of accounting changes on revenue requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide two comparisons between (i) IFF14 and IFF13 and (ii) IFF 14 with IFF11-2.

RATIONALE FOR QUESTION:

Review forecast changes to OM&A excluding the impacts related to IFRS.

RESPONSE:

MH14 vs MH13

The decrease in cost per customer for 2014 compared to forecast is primarily due to vacancies as a result of cost containment efforts. In addition there were lower construction and maintenance service costs partly due to delays in maintenance projects and a deferral of vegetation management. The decrease in cost per customer in 2015 is primarily due to higher capitalized overhead as a result of an increase in capital requirements as well as the impact of various cost containment initiatives. The increase in cost per customer in 2017 is due to increased pension and benefit costs primarily due to changes in the discount rate as well as additional overhead costs no longer eligible for capitalization, partially offset by the impacts of various cost savings initiatives.

MH14 vs MH12

The increase in cost per customer for 2013 and 2014 compared to forecast is primarily due to changes in the discount rate impacting pension and other benefits. The decrease in 2015 is a result of the delay in the implementation of IFRS from 2015 in MH12 to 2016 in MH14. The overall decrease in 2016 and 2017 reflects the impact of various cost savings initiatives.

Similar information was provided in Appendix 11.29; however the MH12 customer numbers have been corrected in this response.

Please see the following tables comparing MH14 to MH13 and MH14 to MH12 OM&A cost per customer.

	Actual							Forecast - MH14		
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' (in millions of $)	323	364	378	397	412	463	481	486	542	552
# of Customers	521 599	527 472	532 359	537 299	542 681	548 774	555 760	561 825	568 443	575 648
OM&A (electric only) per customer (in dollars)	619	691	709	739	759	844	865	865	953	958

	Actual						Forecast - MH13			
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' (in millions of $)	323	364	378	397	412	463	485	494	542	548
# of Customers	521 599	527 472	532 359	537 299	542 681	548 774	554 957	561 140	567 344	573 555
OM&A (electric only) per customer (in dollars)	619	691	709	739	759	844	873	881	955	955

						Change				
(in millions of dollars)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A (electric only) per customer (in dollars)	-	-	-	-	-	-	(8)	(16)	(2)	3

	Actual							Forecast - MH14		
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' (in millions of $)	323	364	378	397	412	463	481	486	542	552
# of Customers	521 599	527 472	532 359	537 299	542 681	548 774	555 760	561 825	568 443	575 648
OM&A (electric only) per customer (in dollars)	619	691	709	739	759	844	865	865	953	958

	Actual					Forecast - MH12				
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A expense 'electric only' (in millions of $)	323	364	378	397	412	455	471	544	556	567
# of Customers	521 599	527 472	532 359	537 299	542 681	548 944	555 955	563 047	570 205	577 419
OM&A (electric only) per customer (in dollars)	619	691	709	739	759	829	847	965	975	982

						Change				
(in millions of dollars)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
OM&A (electric only) per customer (in dollars)	-	-	-	-	-	14	18	(101)	(22)	(23)

Section:	Tab 5 Appendix 5.5	**Page No.:**	Figure 5.5.5
Topic:	Financial Results & Forecasts		
Subtopic:	Accounting Changes		
Issue:	Impact of accounting changes on revenue requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file an update to PUB/MH I-9 e (2012 GRA) based on IFF14.

RATIONALE FOR QUESTION:

Review forecast changes to OM&A excluding the impacts related to IFRS.

RESPONSE:

Please see the following tables comparing MH14 to MH12.

	Actual						Forecast - MH14														
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OM&A expense 'electric only' (in millions of $)	364	378	397	412	463	481	486	542	552	557	571	585	601	607	619	631	644	657	669	683	697
# of Customers	527 472	532 359	537 299	542 681	548 774	555 760	561 825	568 443	575 648	582 805	589 777	596 602	603 152	609 374	615 257	620 832	626 211	631 327	636 198	640 842	645 338
OM&A per customer (in dollars)	691	709	739	759	844	865	865	953	958	956	968	981	996	996	1 006	1 017	1 028	1 040	1 052	1 065	1 079

	Actual						Forecast - MH14														
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OM&A expense 'electric only' (in millions of $)	364	378	397	412	463	481	486	542	552	557	571	585	601	607	619	631	644	657	669	683	697
CGAAP Changes																					
Intangible assets	5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6
Overhead Capitalized	5	9	29	29	60	61	62	63	63	64	65	65	66	66	68	69	71	72	73	75	76
Change in Pension & Benefits (e.g. Discount rate)	-	-	-	3	14	25	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Subtotal CGAAP Changes	10	13	33	37	78	91	94	95	95	96	97	97	98	99	100	102	103	105	106	108	109
IFRS Changes																					
Administrative Overhead	-	-	-	-	-	-	-	55	55	56	56	57	57	58	59	60	62	63	64	65	67
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Pension	-	-	-	-	-	-	-	0	3	3	3	3	3	3	4	4	4	4	4	4	4
Employee Benefits	-	-	-	-	-	-	-	(3)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Subtotal IFRS Changes	-	-	-	-	-	-	-	51	56	57	58	58	59	60	61	62	63	65	66	67	69
Total OM&A Accounting Changes	10	13	33	37	78	91	94	146	151	153	154	156	157	158	161	164	166	169	172	175	178
OM&A expense 'electric only' net of Accounting Changes	355	364	364	375	385	390	392	396	400	405	417	430	444	448	458	468	478	487	497	508	519
# of Customers	527 472	532 359	537 299	542 681	548 774	555 760	561 825	568 443	575 648	582 805	589 777	596 602	603 152	609 374	615 257	620 832	626 211	631 327	636 198	640 842	645 338
OM&A per customer (in dollars) net of Accounting Changes	672	684	678	692	701	701	698	697	695	694	707	721	736	736	745	753	763	772	782	792	804

	Actual				Forecast - MH12																
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OM&A expense 'electric only' (in millions of $)	364	378	397	412	455	471	544	556	567	590	601	617	639	653	667	681	696	727	741	757	775
CGAAP Changes																					
Intangible assets	5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6
Overhead Capitalized	5	9	29	29	56	58	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78
Change in Pension & Benefits (e.g. Discount rate)	-	-	-	3	8	10	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6
Subtotal CGAAP Changes	10	13	33	37	69	72	68	70	71	72	74	75	77	78	80	81	83	84	86	88	89
IFRS Changes																					
DSM	-	-	-	-	-	-	23	22	21	20	19	18	17	17	17	17	17	16	14	14	15
Site Remediation	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6
Regulatory Costs	-	-	-	-	-	-	1	1	2	1	1	1	1	1	1	1	1	1	1	1	1
Pension	-	-	-	-	-	-	-	2	4	5	7	9	11	12	26	29	33	36	39	43	46
Employee Benefits	-	-	-	-	-	-	(3)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	-	-	-	-
Admin & General	-	-	-	-	-	-	37	38	38	39	40	41	41	42	42	43	44	45	46	47	47
Subtotal IFRS Changes	-	-	-	-	-	-	62	66	69	69	71	73	75	77	92	96	100	104	106	111	116
Total OM&A Accounting Changes	10	13	33	37	69	72	130	135	140	141	145	148	152	156	172	178	183	188	192	199	205
OM&A expense 'electric only' net of Accounting Changes	355	364	364	375	386	399	413	421	427	448	456	469	488	497	495	504	513	539	549	559	570
# of Customers	527 472	532 359	537 299	542 681	548 944	555 955	563 047	570 205	577 419	584 667	591 908	599 130	606 344	613 540	620 702	627 821	634 889	641 901	648 855	655 750	662 582
OM&A per customer (in dollars) net of Accounting Changes	672	684	678	692	703	717	734	738	740	767	771	783	804	810	798	802	808	840	846	852	860

	Change - MH14 vs MH12																				
(in millions of dollars)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OM&A per customer (in dollars)	-	-	-	-	14	18	(101)	(22)	(23)	(53)	(48)	(49)	(58)	(68)	(68)	(68)	(67)	(93)	(90)	(89)	(90)
OM&A per customer (in dollars) net of Accounting Changes	-	-	-	-	(3)	(16)	(36)	(41)	(44)	(73)	(64)	(62)	(68)	(74)	(53)	(49)	(45)	(68)	(64)	(60)	(56)

Section:	Tab 5: Appendix 5.5	**Page No.:**	7-10
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide a description of how MH defines an EFT.

RATIONALE FOR QUESTION:

Wages and benefits including overtime is a component of OM&A expenses

RESPONSE:

An EFT represents the equivalent of an employee working full-time hours of 73.7 hours bi-weekly or 1,921 hours per year.

Section:	Tab 5: Appendix 5.5	Page No.:	7-10
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please refile Figure 5.5.6 including the years 2007/08 to 2011/12.

RATIONALE FOR QUESTION:

Wages and benefits including overtime is a component of OM&A expenses

RESPONSE:

System changes have been implemented beginning in 2012/13 to align Manitoba Hydro's capitalization practices with industry standards and support Manitoba Hydro's transition to IFRS. As a result of these changes, the EFT data is only available in the new format beginning in the 2012/13 fiscal year; information is not available for prior years.

The total EFT data for 2007/08 to 2011/12 can be found in Appendix 11.23.

Section:	Tab 5: Appendix 5.5	**Page No.:**	7-10
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file Figure 5.5.7 including the year 2007/08 through 2011/12

RATIONALE FOR QUESTION:

Wages and benefits including overtime is a component of OM&A expenses

RESPONSE:

Please see the response to PUB/MH-I-32b.

Section:	Tab 5: Appendix 5.5	**Page No.:**	7-10
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the relative payroll and benefits, including overtime associated with each of the years in (b)

RATIONALE FOR QUESTION:

Wages and benefits including overtime is a component of OM&A expenses

RESPONSE:

As discussed in PUB/MH-I-32(b), of this question, Manitoba Hydro implemented system changes beginning in 2012/13 to align Manitoba Hydro's capitalization practices with industry standards and to support Manitoba Hydro's transition to IFRS. As a result of these changes, payroll and benefit information requested can only be provided in the new format beginning in the 2012/13 fiscal year and is shown below:

MANITOBA HYDRO
WAGES, OVERTIME AND BENEFITS

					000s
(Straight Time & Overtime Combined)	**2012/13 Actual**	**2013/14 Actual**	**2014/15 Forecast**	**2015/16 Forecast**	**2016/17 Forecast**
Capital Construction	215,491	234,510	256,588	282,335	287,969
Operations & Maintenance	281,335	296,535	296,332	298,831	308,331
Governance, Support & Services	161,257	168,925	172,073	170,357	169,809
Total Corporation	**658,082**	**699,970**	**724,993**	**751,523**	**766,109**

The breakdown of payroll and benefits, including overtime, for total EFTs from 2007/08 to 2016/17 is as follows:

MANITOBA HYDRO
WAGES, OVERTIME AND BENEFITS

000s

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
(Straight Time & Overtime Combined)	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast
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	157,094	160,592	155,892	158,992
Total Labour & Benefits	477,838	509,592	540,968	571,238	611,356	658,082	699,970	724,993	751,523	766,109
Less: Labour & Benefits Charged to Capital						(215,491)	(234,510)	(256,588)	(282,335)	(287,969)
Labour & Benefits Charged to Operations						**442,591**	**465,460**	**468,405**	**469,188**	**478,140**

As indicated above, Labour & Benefits Charged to Capital can only be provided for 2012/13 and on due to system changes implemented in that year.

Section:	Tab 5: Appendix 5.5	**Page No.:**	7-10
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule for the data in (b) with two additional columns, one providing the Compound Annual Growth Rate for 2007/08 to 2013/14 and another that forecasts the Compound Annual Growth Rate 2013/14 through 2016/17

RATIONALE FOR QUESTION:

Wages and benefits including overtime is a component of OM&A expenses

RESPONSE:

As outlined in part (b) of this question, Manitoba Hydro implemented system changes beginning in 2012/13 to align Manitoba Hydro's capitalization practices with industry standards and to support Manitoba Hydro's transition to IFRS. As a result of these changes, the data requested can only be provided in the new format beginning in the 2012/13 fiscal year.

The tables below provide the compounded annual growth rate from 2013/14 to 2016/17 in the new format as well as the growth rate for total EFTs from 2007/08 to 2013/14.

As indicated, the compounded annual growth over the four years (2013/14 to 2016/17) shows an increase of 5.4% for Capital Construction EFTs and a decrease in both Operations & Maintenance and Governance, Support and Services EFTs. In addition, the growth for total EFTs over the period 2007/08 to 2013/14 is below 2%.

MANITOBA HYDRO
STRAIGHT TIME & OVERTIME EFT'S

	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	Compounded Annual Growth
Capital Construction	2,204	2,362	2,568	2,580	5.4%
Operations & Maintenance	2,908	2,855	2,765	2,733	-2.0%
Governance, Support & Services	1,644	1,647	1,569	1,501	-3.0%
Total Corporation	**6,756**	**6,864**	**6,902**	**6,814**	**0.3%**

MANITOBA HYDRO
STRAIGHT TIME & OVERTIME EFT'S

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	Compounded Annual Growth
Total Corporation	**6,071**	**6,276**	**6,429**	**6,594**	**6,608**	**6,678**	**6,756**	**1.8%**

Section:	Tab 5: Appendix 5.5	**Page No.:**	7-10
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule for the data in (c) with two additional columns one providing the Compound Annual Growth Rate for 2007/08 to 2013/14 and another that forecasts for 2013/14 through 2016/17

RATIONALE FOR QUESTION:

Wages and benefits including overtime is a component of OM&A expenses

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH-I-32e.

Section:	Tab 5: 5.4 Cost Savings Initiatives	Page No.:	45
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate any non-IFRS-related policy changes impacting revenue requirements since 2008 through the test years, and detail the impact of each such policy change.

RATIONALE FOR QUESTION:

MH is targeted staffing reductions.

RESPONSE:

Please see the response to PUB-MH-I-73a, which provides the CGAAP changes impacting revenue requirement from 2009 to 2015. There were no CGAAP changes prior to 2009.

Section:	Tab 5: 5.4 Cost Savings Initiatives	**Page No.:**	45
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate any IFRS-related policy changes impacting revenue requirements since 2008 through the test years, and detail the impact of each such policy change.

RATIONALE FOR QUESTION:

MH is targeted staffing reductions.

RESPONSE:

Please see the response to PUB/MH-I-73a, which provides IFRS changes impacting revenue requirement from 2016 to 2024.

Section:	Tab 5: 5.4 Cost Savings Initiatives	**Page No.:**	45
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide a table detailing, by business unit, annual contract, merit and progression pay increases in each of the test years.

RATIONALE FOR QUESTION:

MH is targeted staffing reductions.

RESPONSE:

Please see the following table by business unit which illustrates the wage and salary increases due to the impact of contract wage settlements, merit and progression for each of the test years.

The total increase in wages and salaries of approximately $63 million over the three year period reflects an average annual increase of approximately 4% each year. Increases for contract wage settlements, merit and progression have been offset by a number of cost saving measures in order to maintain OM&A expenditures at an annual average increase of 1% per year.

MANITOBA HYDRO
ESTIMATED ANNUAL IMPACT OF CONTRACT, MERIT AND PROGRESSION INCREASES

(in millions)	2014/15	2015/16	2016/17	Total
President & CEO	$ 0.1	$ 0.1	$ 0.1	$ 0.4
General Counsel & Corporate Secretary	0.1	0.2	0.1	0.4
Human Resources & Corporate Services	2.2	2.6	2.1	6.9
Corporate Relations	0.5	0.6	0.5	1.6
Finance & Regulatory	0.3	0.3	0.3	0.9
Generation Operations	3.8	4.6	4.1	12.5
Major Capital Projects	0.8	1.1	0.8	2.7
Transmission	5.4	6.4	5.5	17.2
Customer Service & Distribution	4.8	5.8	5.1	15.7
Customer Care & Energy Conservation	1.3	1.6	1.3	4.3
Total	**$ 19.3**	**$ 23.3**	**$ 20.1**	**$ 62.7**
Annual % wage increase	4.1%	4.7%	3.9%	

Section:	Tab 5: 5.4 Cost Savings Initiatives	Page No.:	45
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file an update to PUB/MH I-44 a,b,c,d,e. [2010-03-25] and in the case of part (a) and (b) add to the historical years included in the response.

RATIONALE FOR QUESTION:

MH is targeted staffing reductions.

RESPONSE:

Please find attached an update to Manitoba Hydro's response to PUB/MH I-44 a), b), c) and d) from the 2010 GRA, which was revised in PUB/MH I-77aR.

<u>PUB/MH I-44a (PUB/MH I-77aR)</u>

Every termination is classified into one of 14 termination codes. The termination codes are grouped into five broad termination types: retirement, resignation, health-related, involuntary termination, and job completion. For the years 2005 through 2011, resignation terminations are as follows (all numbers reported in this section exclude students and term employees):

Termination code	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total
Resignation codes											
Another job	17	18	31	30	9	20	31	32	33	50	271
Leaving province/Work locale	14	12	17	11	5	9	9	4	10	12	103
Leaving work force	0	2	2	3	8	6	1	3	3	4	32
Personal/No reason given	11	15	15	18	19	19	14	14	16	25	166
Returning to school	2	0	1	1	5	3	8	1	5	0	26
Resignation sub-total	44	47	66	63	46	57	63	54	67	91	598
Retirement	118	127	168	138	141	146	182	144	150	166	1480
Health-related	12	13	17	16	17	21	10	19	10	10	145
Involuntary termination	8	8	14	7	7	8	7	4	11	8	82
Job completed	2	0	0	0	0	1	0	0	2	3	8
Total	184	195	265	224	211	233	262	221	240	278	2313

PUB/MH I-44b (PUB/MH I-77b)

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

Definitions

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.

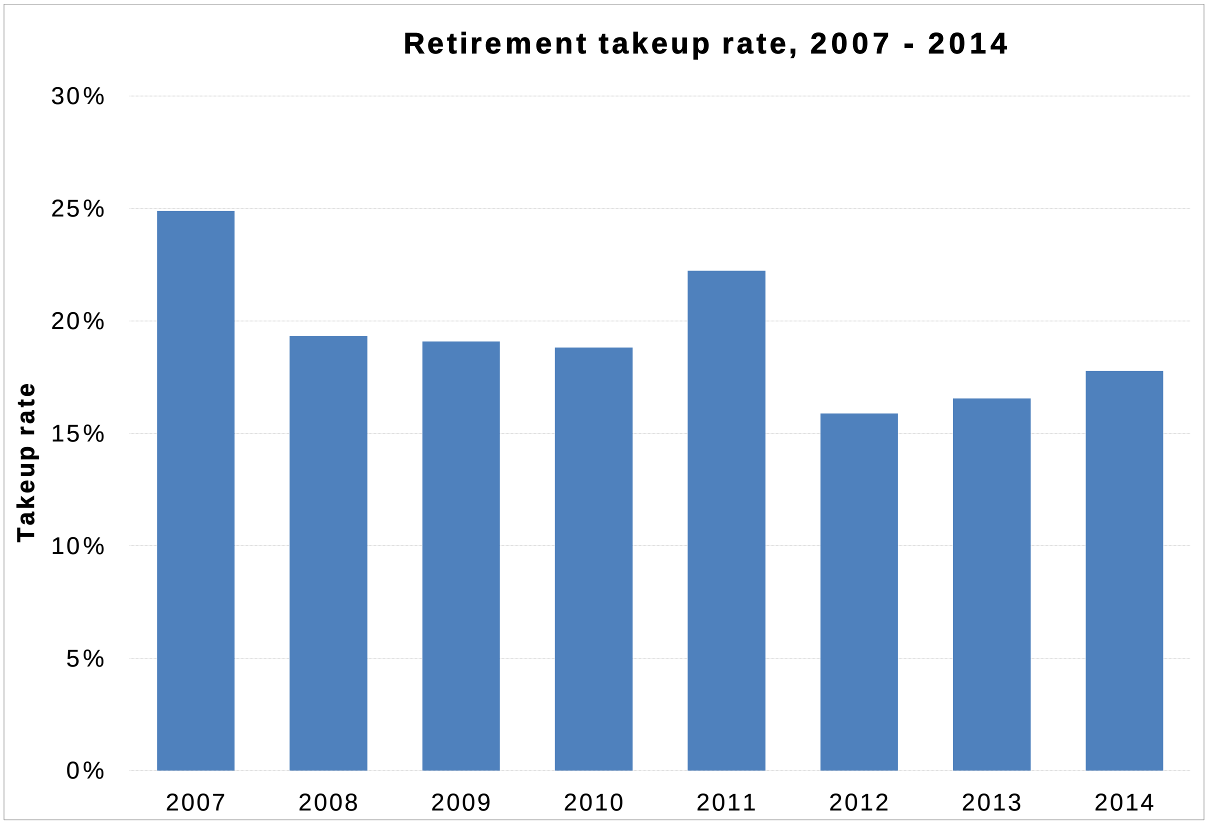
Number eligible in current year: those becoming eligible for a full, undiscounted pension in 2015 (based on age and years of service.) Includes individuals who were eligible in previous years but who have not taken up the retirement opportunity.

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.

PUB/MH I-44c (PUB/MH I-77c)

The retirement take-up rate is based on historical observation. At the beginning of the calendar year, Manitoba Hydro determines the number of people eligible for a full, undiscounted pension based on age and years of service. The retirement take-up rate for a year is the portion of the fully-eligible population which actually “takes up” the retirement opportunity.



PUB/MH I-44d

There have not been any further updates since the response provided on this topic at the 2012 GRA under item PUB/MH I-77(d).

As historical information (with updates to the number of active employees in the WCEBP and curtailed Centra plans, along with an update to the Health Spending Account benefit), the following information from the 2010 PUB/MH I-44 provides a good summary of the retirement eligibility policies.

Manitoba Hydro is a participating employer in the Civil Service Superannuation Board (CSSB) plan. This fund is governed by the Civil Service Superannuation Act and Regulations. Employees are eligible to retire on or after their 65th birthday providing they have at least one year of qualifying service. Employees can retire early, any time on or after age 55, if they have at least 10 years of qualifying service. Employees must stop making pension contributions and begin receiving a pension by December 31 of the year they turn age 71. This does not mean that the member must stop working at that age.

If employees retire between the ages of 55 and 60, their pension is unreduced if they meet the "Rule of 80". The Rule of 80 is when the combination of age (minimum age 55) and qualifying service equals 80 or more (e.g. Age 55 with 25 years of qualifying service or more). The pension is also unreduced if the employee retires on or after their 60th birthday with 10 years of service.

Manitoba Hydro also is a participating employer in the Winnipeg Civic Employee Benefits Program (WCEBP). Manitoba Hydro became a participating employer with the purchase of Winnipeg Hydro in 2002. A closed group of employees (approx. 500) continue to be members in this plan. This plan is also a defined benefit plan that provides for early retirement provisions, similar to the CSSB.

Manitoba Hydro also administers three curtailed pension plans know as the "Centra" plans. Although the plans are curtailed, accumulated pension values up to 2002 are maintained for the former Centra Gas employees. This group of employees (approx. 375) are now active participants of the CSSB.

PUB/MH I-44e

There are no specific policies in place to incent workers to stay beyond their earliest retirement date.

Section:	Tab 5: 5.4 Cost Savings Initiatives	**Page No.:**	45
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

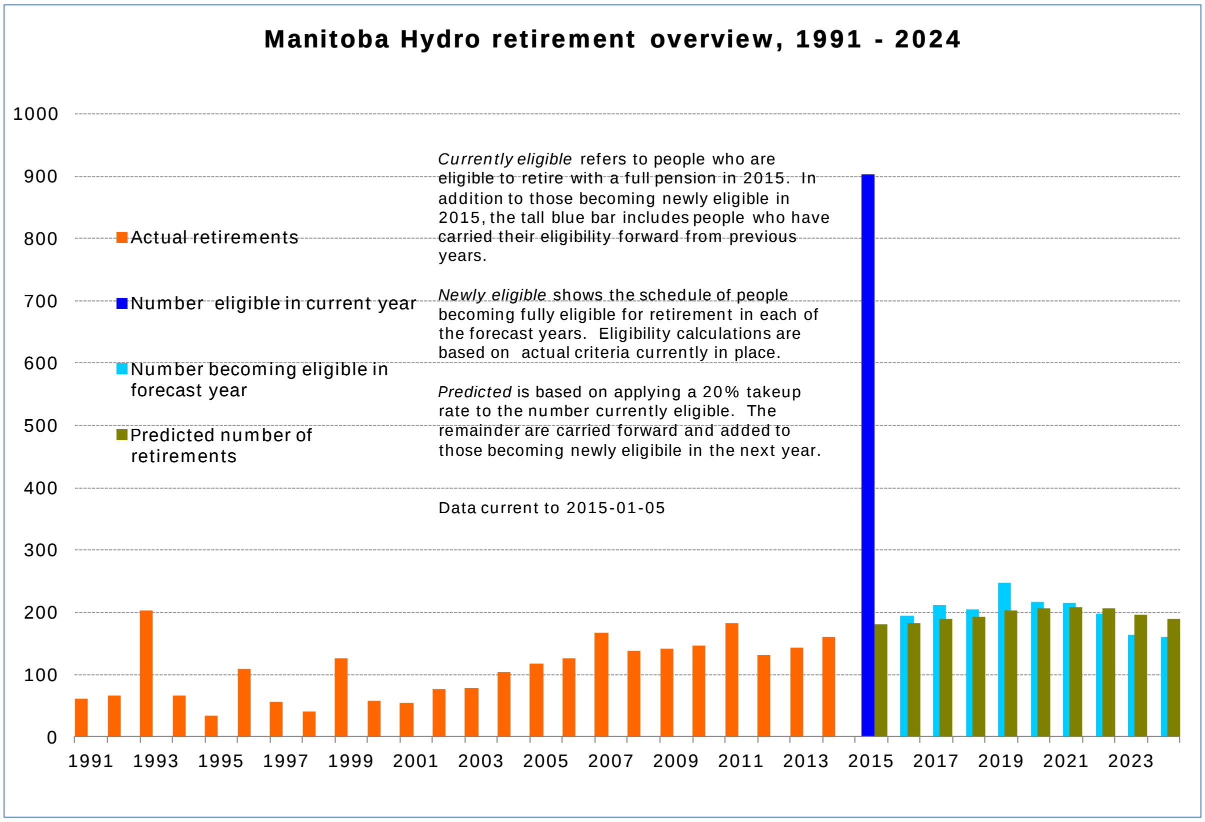
Please provide an updated graph found on page 6 of 36 of Appendix 4.4 of the 2010 GRA.

RATIONALE FOR QUESTION:

MH is targeted staffing reductions.

RESPONSE:

The following chart describes past retirement outcomes and future retirement projections, covering the period 1991-2024.


Manitoba Hydro retirement overview, 1991 - 2024
Actual retirements
Number eligible in current year
Number becoming eligible in forecast year
Predicted number of retirements
Currently eligible refers to people who are eligible to retire with a full pension in 2015. In addition to those becoming newly eligible in 2015, the tall blue bar includes people who have carried their eligibility forward from previous years.
Newly eligible shows the schedule of people becoming fully eligible for retirement in each of the forecast years. Eligibility calculations are based on actual criteria currently in place.
Predicted is based on applying a 20% takeup rate to the number currently eligible. The remainder are carried forward and added to those becoming newly eligibile in the next year.
Data current to 2015-01-05
1000
900
800
700
600
500
400
300
200
100
0
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

Section:	Tab 5: 5.4 Cost Savings Initiatives	Page No.:	45
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a comparison of actual retirement experience with that forecast in 2010 for the period 2010/11 to 2014/15

RATIONALE FOR QUESTION:

MH is targeted staffing reductions.

RESPONSE:

Retirements are tied to birth dates, service anniversaries and taxation issues, and therefore forecasting and planning of retirements are conducted on a calendar year basis. The following table shows retirement forecasts made at the beginning of 2010, together with actual retirement outcomes for the calendar years 2010 through 2014.

Calendar year	2010 Forecast	Actual
2010	155	146
2011	161	182
2012	165	132
2013	167	144
2014	172	161

Section:	Tab 5: Appendix 5.5	**Page No.:**	Figure 5.5.8 p. 10
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expense		
Issue:	Cost Savings Initiatives		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's cost saving initiatives include EFT reductions.

QUESTION:

Please indicate where the targeted 300 EFT reductions are reflected in Figure 5.5.8 for the years 2014/15 through 2016/17.

RATIONALE FOR QUESTION:

Manitoba Hydro's cost saving initiatives include EFT reductions.

RESPONSE:

Appendix 5.5, figure 5.5.3 outlines by Business Unit the committed reduction of 300 operational positions reflecting the Corporations commitment to manage its operating costs.

Figure 5.5.8 provides the forecasted EFT levels by Business Unit required to support the Corporation's operations, maintenance and capital construction functions and incorporates the 300 position reduction.

An EFT is equivalent full time and several part time or term positions can equate to 1 EFT over a fiscal year.

Section:	Tab 5: Appendix 5.5 Figure 5.5.14	Page No.:	12
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expense		
Issue:	Cost Savings Initiatives		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate the total number of EFT's (in Figure 5.5.10) by Business Unit working on Conawapa in 2012/13 and 2013/14 and the respective payroll costs including benefits and overtime

RATIONALE FOR QUESTION:

RESPONSE:

The attached table provides a summary of total EFTs and the associated payroll costs by Business Unit working on Conawapa in 2012/13 and 2013/14. EFTs and the associated payroll costs are calculated based upon hours charged to the Conawapa Generation project by staff throughout the Corporation, utilizing their respective activity rates.

Prior to the suspension of the Conawapa Generation project, activities engaged in by the Corporation included the Needs For and Alternatives To (NFAT) hearing, environmental assessments and studies in preparation of the Environmental Impact Statement, negotiations with First Nations, Aboriginal Traditional Knowledge studies and engineering design.

MANITOBA HYDRO
CONAWAPA EFTS AND PAYROLL COST

(In thousands of $)	2012/13 Actual			2013/14 Actual		
	ST EFTs	**OT EFTs**	**Payroll Cost**	**ST EFTs**	**OT EFTs**	**Payroll Cost**
General Counsel & Corporate Secretary	0	0	0	2	0	303
Corporate Relations	1	0	119	1	0	80
Finance & Regulatory	1	0	59	3	0	381
Generation Operations	14	1	1,672	22	2	2,721
Major Capital Projects	22	3	2,805	29	5	4,084
Transmission	2	0	229	2	0	211
Customer Care & Energy Conservation	0	0	0	4	0	328
Business Unit Total	**40**	**4**	**4,884**	**63**	**7**	**8,108**

Section:	Tab 5: Appendix 5.5 Figure 5.5.14	**Page No.:**	12
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expense		
Issue:	Cost Savings Initiatives		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate the number of EFT's working on Conawapa in 2014/15, 2015/16 and 2016/17 and the respective payroll costs including benefits and overtime

RATIONALE FOR QUESTION:

Manitoba Hydro's cost saving initiatives include EFT reductions.

RESPONSE:

The attached table provides a summary of total EFTs and payroll costs by Business Unit for 2014/15 through 2016/17. EFTs and the associated payroll costs are calculated based upon hours forecasted to be charged to the Conawapa Generation project by staff throughout the Corporation, utilizing their respective activity rates.

The number of EFTs significantly decrease following the August 2014 decision to suspend construction activities. MIPUG/MH-I-10a provides a description of the activities engaged in by the Corporation over the forecast period.

MANITOBA HYDRO
CONAWAPA EFTS AND PAYROLL COST

(In thousands of $)	2014/15 Forecast			2015/16 Forecast			2016/17 Forecast		
	ST EFTs	**OT EFTs**	**Payroll Cost**	**ST EFTs**	**OT EFTs**	**Payroll Cost**	**ST EFTs**	**OT EFTs**	**Payroll Cost**
General Counsel & Corporate Secretary	1	0	139	0	0	0	0	0	0
Finance & Regulatory	1	0	122	0	0	0	0	0	0
Generation Operations	7	1	932	1	0	102	0	0	0
Major Capital Projects	17	3	2,444	8	2	1,315	3	1	519
Business Unit Total	**26**	**4**	**3,637**	**9**	**2**	**1,417**	**3**	**1**	**519**

Section:	Tab 5: Section 5.13	Page No.:	43
Topic:	Financial Results & Forecasts		
Subtopic:	Non-Controlling Interest		
Issue:	Changes in Financial Arrangements with WPLP & KHLP		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide an explanation and detailed calculation of the determination of export revenue forecast for WPLP based on IFF14.

RATIONALE FOR QUESTION:

Non-controlling interest revenues impact Manitoba Hydro's revenue requirement.

RESPONSE:

Please see the response to PUB/MH-I 11(d).

Section:	Tab 5: Section 5.13	**Page No.:**	43
Topic:	Financial Results & Forecasts		
Subtopic:	Non-Controlling Interest		
Issue:	Changes in Financial Arrangements with WPLP & KHLP		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file the updated PDA with WPLP (in confidence if required) and provide details on the changes to the financial arrangements between Manitoba Hydro and WPLP.

RATIONALE FOR QUESTION:

Non-controlling interest revenues impact Manitoba Hydro's revenue requirement.

RESPONSE:

Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) signed the Wuskwatim Project Development Agreement (PDA) Second Supplementary Agreement (Supplement #2) on April 16, 2015 and is effective April 1, 2014. The original PDA was signed in 2006 and the first Supplementary Agreement was signed in 2011. The two supplementary agreements were negotiated to address the diminished financial performance of the Wuskwatim Project compared to when the PDA was ratified in 2006 mainly due to the lower than expected export prices and higher capital costs.

Pursuant to PUB Order 33/15, a description of the underlying changes in assumptions from the existing agreement that were incorporated into the GRA based on terms under negotiations as at the time MH14 was prepared were submitted in confidence to the PUB. The terms outlined in the confidential response included:

- Deferring TPC's final investment settlement date to March 31, 2015;

- Increasing the total equity loan available to TPC to maintain 33% ownership interest at the final settlement date;
- Refinancing the Nisi Trust $40 million mitigation bond at market coupon rates;
- Increasing the dividend loan advances available for 2014 and 2015 (calendar year);
- Annual payments of $2.5 million for 20 years from Manitoba Hydro;
- Operating cash calls at the discretion of the General Partner Board of Directors rather than to maintain debt/equity covenants;
- Eliminating the availability of operating cash call advances to NCN;
- Eliminating the interest rate premiums on TPC and NCN loans;
- Amending the Power Purchase Agreement (PPA) to align the price of Wuskwatim energy to system unit revenues rather than exports only for a 10 year period (see PUB/MH-I-11d); and
- Eliminating the 3% marketing risk fee until TPC and NCN loans are fully repaid to Manitoba Hydro and then increasing the marketing risk fee to approximately 36%.

The projected net impact to Manitoba Hydro averages approximately $15 million per year over the 20-year forecast period due to the following:

- Reductions in accrued interest income on NCN loans receivable;
- Accretion and amortization of the obligation related to the annual payments from Manitoba Hydro;
- Reductions in non-controlling interest due to the potential dilution in NCN ownership interest as a result of the elimination of operating cash call advances available; and
- Changes in non-controlling interest due to the amendments to WPLP revenue pricing.

From the period when MH14 was prepared to the signing of the final Supplement #2, there were no fundamental changes to the terms outlined above, only refinement of the PPA pricing formula and the interest calculations.

One substantive additional provision was introduced in Supplement #2 for a revenue adjustment to the WPLP PPA to account for unanticipated lost generation. Wuskwatim has recently experienced a much higher amount of lost generation under high system flows than was described or projected during the original PDA negotiations and project simulations provided to NCN. The adjustment grosses-up WPLP revenue in 2014/15 to the level of lost generation that was anticipated and projected at the time of ratification.

The Supplement #2 terms take effect in 2014/15, in accordance with the finalized agreement. MH14 assumed that the terms of the agreement would take effect in 2015/16.

The impact on 2014/15 Manitoba Hydro projected net income as a result of changes subsequent to MH14 is as follows:

		$Millions
MH14 Electric Operations Projected Net Income		**$102**
Finance Expense:		
Elimination of interest rate premiums on loans receivable from TPC & NCN		(1)
Non-controlling interest:		
PPA pricing formula	30	
Elimination of marketing risk fee (increase to revenue)	1	
Unanticipated lost generation revenue adjustment	12	
	43	
NCN's ownership interest	33%	
		(14)
Adjusted Electric Operations Projected Net Income		**$87**

The Wuskwatim PDA and associated revised and amended agreements can be found in Appendix 11.50.

Section:	5	**Page No.:**	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

Confirm that IFF14 assumes a switch to ELG and a removal of net salvage in 2015/16 and that depreciation expense for the entire IFF14 period until 2034 is calculated on that basis. If not, please clarify.

RATIONALE FOR QUESTION:

This Information Request seeks to assess the impact on rates of a change to the accounting methods used to determine depreciation expense over the IFF period.

RESPONSE:

It is confirmed that IFF14 assumes a change to the ELG method of depreciation and removal of negative salvage in depreciation rates in 2015/16 through to the end of the IFF14 period 2034.

Section:	5	**Page No.:**	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

If (a) is confirmed, please provide a chart similar to Figure 5.7.1 for the entire IFF14 period.

RATIONALE FOR QUESTION:

RESPONSE:

Please see the attached chart for the net impact on depreciation expense for the 20 year period in IFF14. The cumulative net decrease to depreciation expense as a result of accounting related changes is approximately $2 billion.

	Depreciation Expense ($ millions)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Change in service life - PP&E (net of contributions)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)
Overhead ineligible for Capitalization	-	-	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	-	1	1	1
Elimination of Provision for Asset Removal	-	(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)
Change in Methodology (ELG)	-	36	38	41	49	55	63	67	68	69
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(53)**	**(57)**	**(60)**	**(76)**	**(86)**	**(96)**	**(101)**	**(103)**	**(105)**

	Depreciation Expense ($ millions)										
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	Total
Change in service life - PP&E (net of contributions)	(42)	(40)	(36)	(39)	(40)	(40)	(40)	(39)	(38)	(37)	(746)
Overhead ineligible for Capitalization	(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	13
Elimination of Provision for Asset Removal	(120)	(122)	(125)	(127)	(130)	(132)	(134)	(136)	(140)	(143)	(2,141)
Change in Methodology (ELG)	69	70	72	73	75	76	77	79	80	81	1,238
Net Impact on Depreciation Expense Increase (Decrease)	**(108)**	**(109)**	**(108)**	**(114)**	**(117)**	**(120)**	**(123)**	**(124)**	**(128)**	**(131)**	**(1,946)**

Section:	5	**Page No.:**	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

Confirm whether the ASL-based Gannett Fleming depreciation study filed in the previous GRA was IFRS-compatible. If not, explain why not and what changes would be required for an IFRS-compatible ASL-based depreciation study (e.g., changes to asset groups, etc.)

RATIONALE FOR QUESTION:

RESPONSE:

The ASL based Gannett Fleming depreciation study filed in the previous GRA was not IFRS compliant as the level of asset componentization was not at a sufficient level to satisfy the componentization requirements of IFRS due to the wide dispersion in service lives that exists in many asset groups.

An in-depth depreciation study and auditor review would need to be conducted to identify all new asset components that would be required to develop IFRS compliant ASL based depreciation rates. Please see pages 12 and 13 of Appendix 11.49 (Manitoba Hydro

Response to PUB Order 43/13, Directives #8 & #9) of the application which provides examples of the asset component changes that would be required to continue to use the ASL method and comply with IFRS.

Section:	5	**Page No.:**	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

Provide a break-down of changes to asset classes made between the ASL-based depreciation study filed in the previous GRA and the new ELG-based study filed in the current GRA. Alternatively, confirm that there have been no material changes to the asset classes as represented in Appendix 5.6.

RATIONALE FOR QUESTION:

RESPONSE:

The breakdown of changes to asset classes made between the 2010 ASL-based depreciation study filed in Manitoba Hydro's previous GRA and the 2014 ELG based depreciation study includes only new asset classes added as part of the 2014 depreciation study. The asset class additions are as per the attached listing.

	POINTE DU BOIS - NEW
1111A	DAMS, DYKES AND WEIRS
1111E	WATER CONTROL SYSTEMS
1111F	ROADS AND SITE IMPROVEMENTS
1111P	A/C ELECTRICAL POWER SYSTEMS
1111Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS
1111R	AUXILIARY STATION PROCESSES
1111X	SUPPORT BUILDINGS
1111W	SUPPORT BUILDING RENOVATIONS
	TRANSMISSION
2000Z	COMMUNITY DEVELOPMENT COSTS
	METERS
4900W	METERING EXCHANGES
	BUILDINGS
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE
	WUSKWATIM POWER LIMITED PARTNERSHIP
	HYDRAULIC GENERATION
1181A	WPLP - DAMS, DYKES AND WEIRS
1181B	WPLP - POWERHOUSE
1181C	WPLP - POWERHOUSE RENOVATIONS
1181D	WPLP - SPILLWAY
1181E	WPLP - WATER CONTROL SYSTEMS
1181F	WPLP - ROADS AND SITE IMPROVEMENTS
1181G	WPLP - TURBINES AND GENERATORS
1181H	WPLP - GOVERNORS AND EXCITATION SYSTEM
1181P	WPLP - A/C ELECTRICAL POWER SYSTEMS
1181Q	WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEMS
1181R	WPLP - AUXILIARY STATION PROCESSES
1181X	WPLP - SUPPORT BUILDINGS
1181W	WPLP - SUPPORT BUILDING RENOVATIONS
1181Z	WPLP - OPERATIONAL EMPLOYMENT FUND
	SUBSTATIONS
3081B	WPLP - BUILDINGS
3081F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK
3181R	WPLP - POWER TRANSFORMERS
3181T	WPLP - INTERRUPTING EQUIPMENT
3181U	WPLP - OTHER STATION EQUIPMENT
3181V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES

WUSKWATIM POWER LIMITED PARTNERSHIP cont'd

COMMUNICATION

5081H	WPLP - FIBRE OPTIC AND METALLIC CABLE
5081J	WPLP - CARRIER EQUIPMENT

MOTOR VEHICLES

6081G	WPLP - HEAVY TRUCKS
6081H	WPLP - CONSTRUCTION EQUIPMENT
6081J	WPLP - TRAILERS
6081K	WPLP - MISCELLANEOUS VEHICLES

GENERAL EQUIPMENT

9081K	WPLP - COMPUTER EQUIPMENT

WUSKWATIM POWER LIMITED PARTNERSHIP - INTANGIBLE ASSETS

TRANSMISSION

2080F	WPLP - ROADS, TRAILS AND BRIDGES
2080G	WPLP - METAL TOWERS AND CONCRETE POLES
2080J	WPLP - POLES AND FIXTURES
2080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES
2080Z	WPLP - TRANSMISSION DEVELOPMENT FUND

SUBSTATIONS

3080B	WPLP - BUILDINGS
3080F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK
3180R	WPLP - POWER TRANSFORMERS
3180S	WPLP - OTHER TRANSFORMERS
3180T	WPLP - INTERRUPTING EQUIPMENT
3180U	WPLP - OTHER STATION EQUIPMENT
3180V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES

DISTRIBUTION

4080J	WPLP - POLES AND FIXTURES
4080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES
4080N	WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY
4080S	WPLP - SERIALIZED EQUIPMENT - UNDERGROUND

COMMUNICATION

5080H	WPLP - FIBRE OPTIC AND METALLIC CABLE
5080J	WPLP - CARRIER EQUIPMENT
5080M	WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCING
5080N	WPLP - OPERATIONAL DATA NETWORK

EASEMENTS

A180A	WPLP - EASEMENTS

Section:	5	**Page No.:**	
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes to Asset Lives		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has made a number of significant changes to asset life assumptions (reducing some and extending others) that impact depreciation expense.

QUESTION:

Provide the rationale for, and provide the depreciation expense impact for each of the test years, of the following changes as set out in Appendix 5.6 between the previous 2014/15 ASL rate and the 2015/16 approved ELG rate

i. Pointe du Bois powerhouse
ii. Pointe du Bois spillway
iii. All powerhouse renovations
iv. Licence renewal for Brandon units 5, 6 and 7
v. Combustion turbine overhauls for Brandon units 6 and 7
vi. Distribution services
vii. Electronic meters
viii. Analog meters
ix. Mobile radio, telephone and video conferencing
x. Passenger vehicles
xi. Computer software (communication/operational)
xii. Operational system major software – EMS/SCADA

RATIONALE FOR QUESTION:

This Information Request seeks to examine the material changes to asset lives.

RESPONSE:

The rationale for, and depreciation expense impact of changes with respect to depreciation assumptions for the specified accounts are documented below:

i. Pointe du Bois Powerhouse (Original)

The changes to depreciation rates for the Pointe du Bois Powerhouse are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**4.39%**			
Change to life span date	(1.45%)	$ (88)	$ (88)	$ (88)
2014-15 Approved ASL Rate	**2.94%**			
Removal of Net Salvage on transition to IFRS	(0.39%)		(24)	(24)
2015-16 Approved ELG Rate	**2.55%**			
Net impact of changes		**$ (88)**	**$ (112)**	**$ (112)**

The life span date for Pointe du Bois (original GS) was changed from 2031 to 2040 as Pointe du Bois redevelopment is not expected to occur during the timeframe of the CEF.

ii. Pointe du Bois Spillway (Original)

The changes to depreciation rates for the Pointe du Bois Spillway are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**10.76%**			
Change to life span date	62.81%	$ 3,394	$ 748	$ -
Inclusion of Net Salvage factor	10.96%	592	345	-
2014-15 Approved ASL Rate	**84.53%**			
Change from ASL to ELG on transition to IFRS	(0.20%)		(16)	-
Removal of Net Salvage on transition to IFRS	(10.96%)		(345)	-
2015-16 Approved ELG Rate	**73.37%**			
Net impact of changes		**$ 3,986**	**$ 732**	**$ -**

The life span date for Pointe du Bois (original Spillway) was changed from December 2017 to October 2015, consistent with the advancement of the final in-service date for the Pointe du Bois Spillway Replacement project, at which time the old spillway structure will cease to provide any ongoing benefit to the Corporation. Depreciation rates have been increased to ensure that the assets pertaining to the original Pointe du Bois spillway will be fully depreciated when they are retired in Oct 2015.

A provision for net salvage was included in the 2014-15 Approved ASL depreciation rates for consistency with the other Pointe du Bois asset components.

iii. Powerhouse Renovations (all generating stations)

The changes to depreciation rates for the Powerhouse Renovations are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**4.40%**			
Change in average service life	(1.65%)	$ (29)	$ (29)	$ (29)
2014-15 Approved ASL Rate	**2.75%**			
Removal of Net Salvage on transition to IFRS	(0.25%)		(11)	(11)
2015-16 Approved ELG Rate	**2.50%**			
Net impact of changes		**$ (29)**	**$ (40)**	**$ (40)**

The Powerhouse Renovations account was a new component identified during the 2010 Depreciation Study, for use on a go forward basis. The selected amortization period of 25 years was an initial estimate for expected future costs, as no actual transactions were available for analysis at the time of the 2010 Depreciation Study. During the 2014 Depreciation Study, the nature of actual charges incurred during the 2011-2014 timeframe was considered and the life expectancy was changed to 40 years to better reflect the cycle time for the types of included costs, such as roof replacements, window and door upgrades, lunchroom and washroom upgrades. Manitoba Hydro operational staff indicated that these types of upgrades are typically undertaken at 35 – 40 years, with some cycles as long as 50 years.

The depreciation expense impact figures shown reflect the total for all generating stations. The depreciation rates shown in the above table are the rates in use for the majority of generating stations, in cases for which life span dates and annual true-up do not impact the depreciation rates, and for which the standard -10% salvage factor is used. Actual depreciation rates are higher for Pointe du Bois, Laurie River and Brandon Unit 5 due to the use of life span dates shorter than the 40 year average service life. Depreciation rates for Selkirk GS are lower than those shown as they do not include a salvage factor. Depreciation rates for generating stations with actual charges to the Powerhouse Renovations account vary from the rates shown due to the inclusion of an annual true-up where necessary.

iv. Licence Renewal - Brandon Units 5

The changes to depreciation rates for Licence Renewals - Brandon Unit 5 are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**10.00%**			
Inclusion of life span date	4.81%	$ 106	$ 106	$ 106
2014-15 Approved ASL Rate	**14.81%**			
2015-16 Approved ELG Rate	**14.81%**			
Net impact of changes		**$ 106**	**$ 106**	**$ 106**

The difference in depreciation rate is due to inclusion of the 2020 life span date in the rate calculation for the 2014 Depreciation Study. The life span date was not factored into the depreciation rate calculation during the 2010 Depreciation Study, as there were no actual charges to this account at the time of the 2010 Depreciation Study.

Licence Renewal - Brandon Units 6 and 7

The depreciation assumptions and depreciation rates for Licence Renewal for Brandon Units 6 & 7 have not changed. Both the 2010 Depreciation Study and the 2014 Depreciation Study assume an average service life and IOWA curve of 50-SQ, which results in a depreciation rate of 2.00% under either the ASL or ELG methodology. IFF14 does not include a depreciation forecast for this account as there are no assets in-service for Licence Renewal for Brandon Units 6 & 7.

v. Combustion Turbine Overhauls - Brandon Units 6 and 7

The changes to depreciation rates for Combustion Turbine Overhauls are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**11.00%**			
Change in average service life	(3.67%)	$ -	$ -	$ -
2014-15 Approved ASL Rate	**7.33%**			
Removal of Net Salvage on transition to IFRS	(0.66%)		-	-
2015-16 Approved ELG Rate	**6.67%**			
Net impact of changes		**$ -**	**$ -**	**$ -**

The average service life for the Combustion Turbines Account was extended from 10 to 15 years as the units have not yet reached the operating hours at which the first major overhaul is required. Since the 2010 Depreciation Study, the combustion turbines have been operated less frequently than anticipated at that time, and based on current and expected operating hours, Manitoba Hydro expects the first major overhaul to occur at approximately 15-18 years after the original installation. The change in depreciation rate does not impact the forecast for depreciation expense in IFF14, as there are no actual in-service costs for this account.

vi. Distribution Services

The changes to depreciation rates for the Distribution Services account are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**4.38%**			
Change in average service life	(1.46%)	$ (1,099)	$ (1,190)	$ (1,282)
2014-15 Approved ASL Rate	**2.92%**			
Change from ASL to ELG on transition to IFRS	0.39%		318	342
Removal of Net Salvage on transition to IFRS	(1.42%)		(1,158)	(1,247)
2015-16 Approved ELG Rate	**1.89%**			
Net impact of changes		**$ (1,099)**	**$ (2,030)**	**$ (2,187)**

For the 2014 Depreciation Study, the average service life and IOWA curve for the Distribution Services account was changed from 30-R2 to 35-R1.5 years to better align with the results of the statistical analysis of historical retirement activity.

vii. Meters - Electronic

The changes to depreciation rates for the Meters - Electronic account are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**6.10%**			
Change in average service life	3.51%	$ 679	$ 728	$ 800
2014-15 Approved ASL Rate	**9.61%**			
Change from ASL to ELG on transition to IFRS	0.91%		196	222
2015-16 Approved ELG Rate	**10.52%**			
Net impact of changes		**$ 679**	**$ 924**	**$ 1,022**

For the 2014 Depreciation Study, the average service life and IOWA curve for the Meters – Electronic account was changed from 20-R1.5 to 15-L3 to match the best fit curve resulting from the statistical analysis of historical retirement transactions.

viii. Meters - Analog

The changes to depreciation rates for the Meters - Analog account are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**13.54%**			
Change in average service life	0.03%	$ 6	$ 6	$ 6
Adjustment to annual true-up	(9.73%)	(1,990)	(1,926)	(2,043)
2014-15 Approved ASL Rate	**3.84%**			
Change from ASL to ELG on transition to IFRS	0.37%		73	70
2015-16 Approved ELG Rate	**4.21%**			
Net impact of changes		**$ (1,984)**	**$ (1,847)**	**$ (1,967)**

The primary factor influencing the depreciation rate for this account is the accumulated depreciation variance position. For the 2010 Depreciation Study, the depreciation rate for the Meters – Analog account was increased by 9.72% due to the existence of a large positive accumulated variance at that time. This variance has since been recovered through depreciation charges leaving the account with a small negative accumulated depreciation variance and consequently a small decrease in the depreciation rate of 0.01% for the 2014 Depreciation Study (-9.72% plus -0.01% equals -9.73%).

ix. Mobile Radio, Telephone and Video Conferencing

The changes to depreciation rates for the Mobile Radio, Telephone and Video Conferencing account are due to the following factors:

	Depreciation	Depreciation Expense Impact		
($ 000's)	Rate	2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**10.24%**			
Removal of 2010 depreciation rate adjustment pertaining to assets older than the average service life of the account	6.41%	$ 674	$ 621	$ 621
Adjustment to annual true-up	1.91%	201	102	114
2014-15 Approved ASL Rate	**18.56%**			
Removal of Net Salvage on transition to IFRS	(1.92%)		(163)	(93)
2015-16 Approved ELG Rate	**16.64%**			
Reduction in depreciation expense due to difference in timing of retirement of assets resulting from change to depreciation rate		(107)	(64)	(671)
Net impact of changes		**$ 768**	**$ 496**	**$ (29)**

At the time of the 2010 Depreciation Study, the Mobile Radio, Telephone and Video Conferencing account included a number of assets for which the age of the assets exceeded the average service life of the account, but which were not yet fully depreciated as they had been transferred into the account during componentization of the prior Communication assets. The 2010 ASL depreciation rate was 6.41% lower than it would have been had these assets not been included in the depreciable base. As these assets have since become fully depreciated and have been retired, the 2014 Depreciation Study no longer includes this adjustment to the depreciation rates.

The remaining difference in the 2014/15 ASL based depreciation rates is due primarily to a change in the accumulated depreciation variance position of the account since the 2010 depreciation study.

x. Passenger Vehicles

The changes to depreciation rates for the Passenger Vehicles account are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**11.09%**			
Change in average service life	(1.62%)	$ (18)	$ (18)	$ (18)
Adjustment to annual true-up	(2.44%)	(27)	(27)	(27)
2014-15 Approved ASL Rate	**7.03%**			
Change from ASL to ELG on transition to IFRS	0.56%		6	6
2015-16 Approved ELG Rate	**7.59%**			
Net impact of changes		**$ (45)**	**$ (39)**	**$ (39)**

For the 2014 Depreciation Study, the average service life and IOWA curve for the Passenger Vehicles account was changed from 9-L2 to 11-S2 to match the best fit curve resulting from the statistical analysis of historical retirement transactions. This life extension is consistent with operational experience whereby vehicles are being utilized longer before replacement.

In addition, the positive accumulated depreciation variance present at the 2010 Depreciation Study has been fully recovered, leaving a small negative variance at the 2014 Depreciation Study, As such, the annual true-up adjustment to the rates has been reduced accordingly.

xi. Computer Software - Communication/Operational

The changes to depreciation rates for the Computer Software – Communication/ Operational account are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**13.93%**			
Removal of 2010 depreciation rate adjustment pertaining to assets older than the average service life of the account	10.09%	$ 506	$ 513	$ 492
Adjustment to annual true-up	3.29%	165	167	161
2014-15 Approved ASL Rate	**27.31%**			
2015-16 Approved ELG Rate	**27.31%**			
Reduction in depreciation expense due to difference in timing of retirement of assets resulting from change to depreciation rate		(35)	(213)	(626)
Net impact of changes		**$ 636**	**$ 467**	**$ 27**

At the time of the 2010 Depreciation Study, the Computer Software – Communication/Operational account included a number of assets for which the age of the assets exceeded the average service life of the account, but which were not yet fully depreciated as they had been transferred into the account during componentization of the prior Communication assets. The 2010 ASL depreciation rate was 10.09% lower than it would have been had these assets not been included in the depreciable base. As these assets have since become fully depreciated and have been retired, the 2014 Depreciation Study no longer includes this adjustment to the depreciation rates.

The remaining difference in the 2014/15 ASL based depreciation rates is due primarily to a change in the accumulated depreciation variance position of the account since the 2010 depreciation study.

xii. Operational system major software – EMS/SCADA

The changes to depreciation rates for the Computer Software – EMS/SCADA account are due to the following factors:

($ 000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**23.35%**			
Change in average service life	(2.11%)	$ (219)	$ (224)	$ (230)
Adjustment to annual true-up	(13.18%)	(1,370)	(1,402)	(1,434)
2014-15 Approved ASL Rate	**8.06%**			
Change from ASL to ELG on transition to IFRS	1.27%		136	139
2015-16 Approved ELG Rate	**9.33%**			
Net impact of changes		**$ (1,589)**	**$ (1,490)**	**$ (1,525)**

The primary factor influencing the depreciation rate for this account is the accumulated depreciation variance position. For the 2010 Depreciation Study, the depreciation rate for the Computer Software – EMS/SCADA account was increased by 6.95% due to the existence of a large positive accumulated variance at that time. This variance has since reversed, leaving the account with a negative accumulated depreciation variance which has required removal of the 2010 true-up adjustment plus a further reduction in the depreciation rate of 6.23% for the 2014 Depreciation Study (-6.95% plus -6.23% equals -13.18%).

In addition, the average service life and IOWA curve for the Computer Software – EMS/SCADA account have been updated to match the best fit curve resulting from the statistical analysis of historical retirement transactions. This life extension is consistent with operational experience whereby Manitoba Hydro is achieving 7 years between major system replacements.

Section:	Tab 5 Appendix 5.6	**Page No.:**	VII
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file the full depreciation study in support of the proposed Average Service Life based rates for April 1, 2014.

RATIONALE FOR QUESTION:

To assess whether ASL or ELG should be used for rate setting proposes.

RESPONSE:

A full depreciation study report based on the approved ASL based depreciation rates for April 1, 2014 (as provided in Attachment 1 of Appendix 5.6 of the application) was not produced because the information included in such a report (excluding the results presented in tables 1, 1A, 2, and 2A) would be identical to the information already included in the 2014 depreciation study report based on the approved ELG depreciation rates.

Section:	Tab 5 Appendix 5.6	Page No.:	VII
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a schedule that indicates the Plant Groups, Original Cost and ASL annual accrual, based on the 2010 ASL rates and 2014 ASL rates.

RATIONALE FOR QUESTION:

To assess whether ASL or ELG should be used for rate setting proposes.

RESPONSE:

Please see the attached schedule that indicates the Plant Groups, Original Cost and ASL annual accrual based on the 2010 and 2014 ASL rates as per the respective depreciation studies.

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

Plant Group	2010 Study Original Cost Base	2010 Study ASL Annual Accrual Rate*	2010 Study ASL Annual Accrual $'s	2014 Study Original Cost Base	2014 Study ASL Annual Accrual Rate*	2014 Study ASL Annual Accrual $'s
Generation						
Hydro	**4,716,467,183**	1.48%	69,582,773	**5,445,593,386**	1.65%	89,705,854
Thermal	**430,613,460**	3.44%	14,792,480	**439,575,329**	3.47%	15,270,747
Diesel	**44,622,878**	2.42%	1,078,029	**48,030,666**	3.84%	1,845,608
Transmission	**756,206,167**	1.71%	12,937,797	**980,402,254**	1.58%	15,467,630
Substations	**2,446,844,172**	3.16%	77,232,743	**2,975,185,020**	2.71%	80,566,444
Distribution	**2,378,666,825**	2.41%	57,294,240	**2,875,373,143**	2.24%	64,290,076
General	**1,294,317,255**	6.18%	79,938,315	**1,466,265,753**	5.13%	75,266,372
Total Plant In Service	**12,067,737,940**	**2.59%**	**312,856,377**	**14,230,425,551**	**2.41%**	**342,412,731**

* Please note these rates are not IFRS compliant

Section:	Tab 5 Appendix 5.6	**Page No.:**	VII
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate whether the ASL based study is compliant with IFRS. If not compliant, please explain in detail what aspects of the analysis would be required to be changed to be IFRS compliant.

RATIONALE FOR QUESTION:

To assess whether ASL or ELG should be used for rate setting proposes.

RESPONSE:

The 2014 ASL based Gannett Fleming depreciation study is not IFRS compliant as the level of asset componentization is not at a sufficient level to satisfy the componentization requirements of IFRS due to the wide dispersion in service lives that exist in many asset groups.

An in-depth depreciation study and auditor review would need to be conducted to identify all new asset components that would be required to develop IFRS compliant ASL based depreciation rates. Please see pages 12 and 13 of Appendix 11.49 (Manitoba Hydro Response to PUB Order 43/13, Directives #8 & #9) of the application which provides examples of the asset component changes that would be required to continue to use the ASL method and comply with IFRS.

Section:	Tab 5: Appendix 5.6 Attachment 2	**Page No.:**	
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Impact on Revenue Requirement of use of ASL vs ELG		

PREAMBLE TO IR (IF ANY):

The in-service costs of Bipole III and Keeyask will have a material impact on the depreciation and amortization included in revenue requirement.

QUESTION:

Please provide an updated schedule, similar to that provided on page vii of Appendix 5.6 Attachment 2, that takes the forecasted balance of the plant groups when Bipole III is fully in-service and when Keeyask is fully in-service and provide the detail along with the ELG Annual Accrual at those in-service dates. For the purpose of this Information Request assume no change to the ELG percentages reflected in the chart on page vii of Attachment 2.

RATIONALE FOR QUESTION:

Depreciation & Amortization impact revenue requirements.

RESPONSE:

The following table provides a summary of the forecast average Property, Plant and Equipment in service, and associated depreciation expense, for the 2021/22 fiscal year. Depreciation expense has been calculated using the ELG based depreciation rates from the 2014 Depreciation Study, as included in IFF14. Please note that depreciation associated with the WPLP is not included in either Appendix 5.6, Attachment 2, page vii, or this response.

The ELG percentages shown differ from those reported on page vii of the 2014 Depreciation Study, as the forecast mix of assets within each category differs from the March 31, 2014 plant balances due to forecast plant asset additions and retirements.

PLANT GROUP	FORECAST AVERAGE PLANT IN SERVICE 2021/22 $ 000's	FORECAST DEPRECIATION EXPENSE IFRS (ELG) 2021/22 %'s	FORECAST DEPRECIATION EXPENSE IFRS (ELG) 2021/22 $ 000's
MANITOBA HYDRO			
Generation			
Hydro	$ 7,950,831	1.59	$ 126,084
Thermal	452,862	3.40	15,414
Diesel	52,650	3.34	1,756
Transmission	3,516,821	1.28	45,093
Substations	7,122,683	2.37	168,690
Distribution	4,266,096	2.01	85,614
General	1,991,241	5.06	100,726
Manitoba Hydro - Total Plant in Service	**$ 25,353,184**	**2.14**	**$ 543,377**
KEEYASK HYDROPOWER LIMITED PARTNERSHIP			
Generation			
Hydro	6,048,540	1.33	80,628
Transmission	19,839	1.36	270
Substations	21,294	1.36	290
Distribution	2,467	1.38	34
KHLP - Total Plant in Service	**$ 6,092,140**	**1.33**	**$ 81,222**
Total Plant in Service	**$ 31,445,324**	**1.99**	**$ 624,599**

Section:	Tab 5: Appendix 5.6 Attachment 2	Page No.:	
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Impact on Revenue Requirement of use of ASL vs ELG		

PREAMBLE TO IR (IF ANY):

The in-service costs of Bipole III and Keeyask will have a material impact on the depreciation and amortization included in revenue requirement.

QUESTION:

Please provide the same analysis as in (a) utilizing the 2014 ASL based rates.

RATIONALE FOR QUESTION:

Depreciation & Amortization impact revenue requirements.

RESPONSE:

The following table provides a summary of the forecast average Property, Plant and Equipment in service, and associated depreciation expense, for the 2021/22 fiscal year. Depreciation expense has been calculated using the ASL based depreciation rates from the 2014 Depreciation Study, which include a provision for net salvage. Please note that 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 depreciation figures provided in this response are not IFRS compliant.

The ASL percentages shown differ from those reported within Schedule 1 of the 2014 Depreciation Study – ASL with Salvage tables (Appendix 5.6, Attachment 1), as the forecast mix of assets within each category differs from the March 31, 2014 plant balances due to plant asset additions and retirements forecast for the 2014/15 – 2021/22 fiscal years.

The depreciation expense for Keeyask is the same under CGAAP (ASL) and IFRS (ELG) as the impacts of change to the ELG methodology are offset by the impact of eliminating the provision for asset removal.

PLANT GROUP	FORECAST AVERAGE PLANT IN SERVICE 2021/22	FORECAST DEPRECIATION EXPENSE CGAAP (ASL)* 2021/22	
	$ 000's	%'s	$ 000's
MANITOBA HYDRO			
Generation			
Hydro	$ 7,950,831	1.67	$ 132,979
Thermal	452,862	3.44	15,580
Diesel	52,650	3.13	1,649
Transmission	3,516,821	1.57	55,355
Substations	7,122,683	2.67	190,093
Distribution	4,266,096	2.30	98,277
General	1,991,241	4.92	97,917
Manitoba Hydro - Total Plant in Service	**$ 25,353,184**	**2.33**	**$ 591,850**
KEEYASK HYDROPOWER LIMITED PARTNERSHIP			
Generation			
Hydro	6,048,540	1.33	80,628
Transmission	19,839	1.36	270
Substations	21,294	1.36	290
Distribution	2,467	1.38	34
KHLP - Total Plant in Service	**$ 6,092,140**	**1.33**	**$ 81,222**
Total Plant in Service	**$ 31,445,324**	**2.14**	**$ 673,072**

* The ASL based depreciation figures provided in this schedule are not IFRS compliant.

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	4 of 14
Topic:	Finance Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Salvage value is being removed from depreciation rates commencing in 2054/16 when IFRS is adopted. MH has proposed ASL based accounting changes impacting 2014/15 which includes negative salvage

QUESTION:

Please file the electronic versions of tables 1 & 2 ASL 2014 depreciation rate schedules.

RATIONALE FOR QUESTION:

Negative salvage is being removed in 2015/16 when IFRS is implemented. This questions seeks the impact of removing net salvage for earlier years.

RESPONSE:

Please see the attached electronic files as prepared by Gannett Fleming:

- PUB-MH-I-41a – Attachment 1.xlsx
- PUB-MH-I-41a – Attachment 2.xlsx
- PUB-MH-I-41a – Attachment 3.xlsx
- PUB-MH-I-41a – Attachment 4.xlsx

Please note the depreciation rates included in the attached files are not IFRS compliant.

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	4 of 14
Topic:	Finance Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Salvage value is being removed from depreciation rates commencing in 2054/16 when IFRS is adopted. MH has proposed ASL based accounting changes impacting 2014/15 which includes negative salvage

QUESTION:

Please file the electronic versions in excel of tables in Appendix 5.6 Attachment 2

RATIONALE FOR QUESTION:

Negative salvage is being removed in 2015/16 when IFRS is implemented. This questions seeks the impact of removing net salvage for earlier years.

RESPONSE:

Please see the attached electronic files as prepared by Gannett Fleming:

- PUB-MH-I-41b – Attachment 1.xlsx
- PUB-MH-I-41b – Attachment 2.xlsx
- PUB-MH-I-41b – Attachment 3.xlsx
- PUB-MH-I-41b – Attachment 4.xlsx

Section:	Tab 5: Appendix 5.6 Attachment 4	**Page No.:**	4 of 14
Topic:	Finance Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Salvage value is being removed from depreciation rates commencing in 2054/16 when IFRS is adopted. MH has proposed ASL based accounting changes impacting 2014/15 which includes negative salvage

QUESTION:

Please indicate what the financial impact would be on 2014/15, 2015/16 and 20156/17 removing the impact of negative salvage from the 2014 ASL depreciation adjustments.

RATIONALE FOR QUESTION:

Negative salvage is being removed in 2015/16 when IFRS is implemented. This questions seeks the impact of removing net salvage for earlier years.

RESPONSE:

The reduction in depreciation expense for removing the impact of negative salvage for the 2014/15, 2015/16, and 2016/17 years are as follows:

($ millions)

	2014/15	**2015/16**	**2016/17**
Reduction in depreciation expense for removing negative salvage	57	60	63

Please note that removing negative salvage from depreciation rates in fiscal 2014/15 under CGAAP would be considered a change in accounting policy which would require retrospective treatment (i.e. adjustment to the April 1, 2014 retained earnings for prior years' negative salvage amounts) going back as far as Manitoba Hydro's records would permit. Such an adjustment would be inconsistent with past decisions of the PUB. As found by the PUB 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 negative salvage from depreciation rates upon transition to IFRS has 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.

Section:	Tab 5: Appendix 5.6 Attachment 4	**Page No.:**	4 of 14
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Gannet Flemming (GF) has indicated that ELG and ASL were both acceptable approaches under IFRS. MH has stated previously IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

QUESTION:

Please confirm that IAS 16 under IFRS does not preclude the use of ASL for financial reporting purposes or regulatory purposes.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

Manitoba Hydro confirms that IFRS section IAS 16 Property, plant and equipment does not preclude the use of the ASL method of depreciation for financial reporting purposes. However, the more explicit requirements of IAS 16 permit the use of the ASL method for calculating depreciation expense for financial reporting purposes only when a sufficient level of asset componentization exists. Manitoba Hydro's current level of asset componentization is not at a sufficient level to satisfy the componentization requirements of IFRS.

Section:	Tab 5: Appendix 5.6 Attachment 4	**Page No.:**	4 of 14
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Gannet Flemming (GF) has indicated that ELG and ASL were both acceptable approaches under IFRS. MH has stated previously IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

QUESTION:

Please update GF response to PUB/MH I-85 (a) from the 2012 GRA and indicate the number of utilities in Canada and the United states that are using ASL.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

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

The following attachment was provided by Gannett Fleming.

Attachment 1

DETAILED LIST OF UTILITIES THROUGHOUT NORTH AMERICA USING ELG PROCEDURE

Company Name	Approved by:
Allegheny Energy Supply, Inc.	Gannett Fleming cannot confirm that ELG has been approved
AltaGas Utilities Inc.	Alberta Utilities Commission
ATCO Gas	Alberta Utilities Commission
ATCO Electric	Alberta Utilities Commission
Aqua Pennsylvania	Pennsylvania Public Utilities Commission
Citizens Energy Group	Gannett Fleming cannot confirm that ELG has been approved
Columbia Gas of Kentucky	Kentucky Public Service Commission
Columbia Gas of Pennsylvania	Pennsylvania Public Utilities Commission
Duquesne Light Company	Pennsylvania Public Utilities Commission
Duke Energy Indiana	Indiana Utility Regulatory Commission
Duke Energy Kentucky	Kentucky Public Service Commission
East Kentucky Power Cooperative	Kentucky Public Service Commission
Enmax Power Corporation	Alberta Utilities Commission
FortisAlberta Utilities, Inc.	Alberta Utilities Commission
Kokomo Gas and Fuel Company	Indiana Utility Regulatory Commission
National Fuel Gas Distribution Corp - Pa Division	Pennsylvania Public Utilities Commission
Newfoundland Power Limited	Newfoundland and Labrador Board of Commissioners of Public Utilities
Northern Indiana Fuel and Light Company Inc.	Indiana Utility Regulatory Commission
Northern Indiana Public Service Company	Indiana Utility Regulatory Commission
Northland Utilities (NWT) Limited	Northwest Territories Public Utilities Board
Northland Utilities (Yellowknife) Limited	Northwest Territories Public Utilities Board
Nova Scotia Power, Inc.	Nova Scotia Utility and Review Board
Pennsylvania American Water Company	Pennsylvania Public Utilities Commission
Peoples Equitable Gas	Pennsylvania Public Utilities Commission
Peoples Natural Gas	Pennsylvania Public Utilities Commission
Peoples TWP	Pennsylvania Public Utilities Commission
Public Service Company of Colorado	Colorado Public Utilities Commission
Quilliq Power Corporation	Nunavut Utility Rates Review Council
UGI Penn Natural Gas, Inc.	Pennsylvania Public Utilities Commission
UGI Utilities, Inc. - Electric Division	Pennsylvania Public Utilities Commission
York Water Company	Pennsylvania Public Utilities Commission

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	4 of 14
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Gannet Flemming (GF) has indicated that ELG and ASL were both acceptable approaches under IFRS. MH has stated previously IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

QUESTION:

Please provide the composite weighted average rate by Class under the ASL versus ELG methodology for 2015/16 rates.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

Please see the attached table for the composite weighted average depreciation rates by class under the ASL and ELG methodologies as per the 2014 depreciation study. The ELG rates were used for the forecast of depreciation expense for fiscal 2015/16 under IFRS. The ASL rates are only applicable for fiscal 2014/15 under CGAAP.

MANITOBA HYDRO - ELECTRIC OPERATIONS
SUMMARY OF DEPRECIATION ACCRUAL PERCENTAGES

Plant Group	ELG Rates	ASL Rates*
Generation		
Hydro	1.54%	1.65%
Thermal	3.44%	3.47%
Diesel	4.03%	3.84%
Transmission	1.28%	1.58%
Substations	2.40%	2.71%
Distribution	1.98%	2.24%
General	5.27%	5.13%
Total Plant In Service	2.24%	2.41%

* Please note these rates are not IFRS compliant

Section:	5: Appendix 5.6 Attachment II	Page No.:	ii-5
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Changes in Depreciation Rates		

PREAMBLE TO IR (IF ANY):

GF states Amortization accounting is used for certain accounts that contain a large volume of small dollar value assets where the effort required to maintain detailed records is not warranted. Many electric utilities in North America have received approval to adopt amortization accounting for these types of accounts.

QUESTION:

Please provide a comparison between:

a) the accounts subject to amortization accounting in the 2010 depreciation study with those listed in the current study;

RATIONALE FOR QUESTION:

RESPONSE:

Please refer to the table in PUB/MH-I-43b for a listing of accounts subject to amortization accounting in the 2010 depreciation study and those listed in the 2014 study.

Section:	5: Appendix 5.6 Attachment II	Page No.:	ii-5
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Changes in Depreciation Rates		

PREAMBLE TO IR (IF ANY):

GF states Amortization accounting is used for certain accounts that contain a large volume of small dollar value assets where the effort required to maintain detailed records is not warranted. Many electric utilities in North America have received approval to adopt amortization accounting for these types of accounts.

QUESTION:

Please provide a comparison between:

b) the balance of assets subject to amortization and the annual amortization cost in 2010 vs 2014.

RATIONALE FOR QUESTION:

RESPONSE:

Please see the table below for a listing of accounts subject to amortization accounting, the balance of assets subject to amortization and the annual amortization cost (Average Service Life schedules) in the 2010 depreciation study and the 2014 study.

Amortization Method Accounts

2010 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2014 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2010 Amortization Period	2014 Amortization Period	March 31, 2010 Surviving Original Cost	2010 Annual Amortization	March 31, 2014 Surviving Original Cost	2014 Annual Amortization
HYDRAULIC GENERATION	**HYDRAULIC GENERATION**						
GREAT FALLS	**GREAT FALLS**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	47 039	1 255
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	18 859	1 037
POINTE DU BOIS - Original	**POINTE DU BOIS - Original**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	1 897 782	77 887
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	347 164	15 519
	POINTE DU BOIS - New						
	Support Building Renovations		20	-	-	-	-
SEVEN SISTERS	**SEVEN SISTERS**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	578 473	15 435
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
SLAVE FALLS	**SLAVE FALLS**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
PINE FALLS	**PINE FALLS**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	121 809	3 249
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
Community Development Costs	Community Development Costs	81	78	4 425 543	51 963	26 531 770	339 607
MCARTHUR FALLS	**MCARTHUR FALLS**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	405 461	10 812
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
KELSEY	**KELSEY**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	1 598 817	79 656

Amortization Method Accounts cont'd

2010 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2014 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2010 Expected Service Life	2014 Expected Service Life	March 31, 2010 Surviving Original Cost	2010 Annual Amortization	March 31, 2014 Surviving Original Cost	2014 Annual Amortization
GRAND RAPIDS	**GRAND RAPIDS**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	31 603	806
Licence Renewal	Licence Renewal	50	50	-	-	83 122 204	1 662 444
Support Building Renovations	Support Building Renovations	20	20	-	-	6 828 234	387 232
Community Development Costs ***	Community Development Costs ***	80	79	101 442 997	1 177 409	135 205 073	1 630 538
KETTLE	**KETTLE**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
LAURIE RIVER	**LAURIE RIVER**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
JENPEG	**JENPEG**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	26 446	727
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
LAKE WINNIPEG REGULATION	**LAKE WINNIPEG REGULATION**						
Licence Renewal	Licence Renewal	50	50	-	-	250 000	5 041
Community Development Costs	Community Development Costs	100	85	387 802 871	3 654 706	436 787 857	5 154 097
CHURCHILL RIVER DIVERSION	**CHURCHILL RIVER DIVERSION**						
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
Community Development Costs	Community Development Costs	100	90	305 036 524	2 822 351	351 065 147	3 746 057
LONG SPRUCE	**LONG SPRUCE**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	205 681	11 312
LIMESTONE	**LIMESTONE**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	652 644	35 895
WUSKWATIM	**WUSKWATIM**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
INFRASTRUCTURE SUPPORTING GENERATION	**INFRASTRUCTURE SUPPORTING GENERATION**						
Town Site Buildings Renovations	Town Site Buildings Renovations	20	20	13 502 581	802 686	27 027 620	1 432 464

Amortization Method Accounts cont'd

2010 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2014 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2010 Expected Service Life	2014 Expected Service Life	March 31, 2010 Surviving Original Cost	2 010 Annual Amortization	March 31, 2014 Surviving Original Cost	2 014 Annual Amortization
THERMAL GENERATION	**THERMAL GENERATION**						
BRANDON UNIT 5 (COAL)	**BRANDON UNIT 5 (COAL)**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	396 538	62 963
Licence Renewal	Licence Renewal	50	50	-	-	2 198 654	325 621
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
BRANDON UNITS 6 AND 7	**BRANDON UNITS 6 AND 7**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	144 571	3 931
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Combustion Turbine Overhauls	Combustion Turbine Overhauls	10	15	-	-	-	-
SELKIRK	**SELKIRK**						
Powerhouse Renovations	Powerhouse Renovations	25	40	-	-	451 038	11 040
Licence Renewal	Licence Renewal	50	50	-	-	-	-
Support Building Renovations	Support Building Renovations	20	20	-	-	-	-
DIESEL GENERATION	**DIESEL GENERATION**						
Building Renovations	Building Renovations	15	15	17 685	909	17 929	1 196
Engines And Generators - Overhauls	Engines And Generators - Overhauls	5	4	-	-	1 998 461	499 615
TRANSMISSION	**TRANSMISSION**						
Ground Line Treatment	Ground Line Treatment	10	10	1 410 002	141 000	2 297 990	229 799
	Community Development Costs ***		79	-	-	17 625 510	223 152
SUBSTATIONS	**SUBSTATIONS**						
Building Renovations	Building Renovations	20	20	32 047	1 602	16 023 446	800 762
	Synchronous Condenser Overhauls		15	-	-	47 815 173	3 420 109
DISTRIBUTION	**DISTRIBUTION**						
Ground Line Treatment	Ground Line Treatment	10	12	33 145 019	3 175 797	34 478 470	2 547 273
Electronic Equipment	Electronic Equipment	10	10	-	-	739 972	77 899
	METERS						
	Metering Exchanges		15	-	-	33 545 519	2 237 486
COMMUNICATION	**COMMUNICATION**						
Building Renovations	Building Renovations	20	20	2 741 652	155 480	3 486 352	172 742
Operational It Equipment	Operational It Equipment	5	5	2 197 495	504 682	4 821 768	1 012 571
Mobile Radio, Telephone and Video Conferencing	Mobile Radio, Telephone and Video Conferencing	8	8	22 085 412	2 261 449	8 862 073	1 644 384
Operational Data Network	Operational Data Network	8	8	8 530 264	1 202 371	18 817 356	2 469 778

Amortization Method Accounts cont'd

2010 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2014 DEPRECIATION STUDY DEPRECIABLE GROUP (Electric Operations)	2010 Expected Service Life	2014 Expected Service Life	March 31, 2010 Surviving Original Cost	2 010 Annual Amortization	March 31, 2014 Surviving Original Cost	2 014 Annual Amortization
BUILDINGS	**BUILDINGS**						
Building Renovations	Building Renovations	20	20	46 779 508	3 341 129	37 401 024	2 092 287
	Leasehold Improvements - Sony Place		10	-	-	1 007 453	100 745
GENERAL EQUIPMENT	**GENERAL EQUIPMENT**						
Tools, Shop and Garage Equipment	Tools, Shop and Garage Equipment	15	15	78 461 837	6 076 101	87 537 592	5 676 211
Computer Equipment	Computer Equipment	5	5	48 379 758	13 777 169	49 555 418	9 911 084
Office Furniture and Equipment	Office Furniture and Equipment	20	20	21 726 896	1 045 324	26 318 137	1 315 907
Hot Water Tanks	Hot Water Tanks	6	6	4 511 783	956 723	881 848	147 004
	EASEMENTS						
	Easements		75	-	-	66 021 103	878 081
COMPUTER SOFTWARE AND DEVELOPMENT	**COMPUTER SOFTWARE AND DEVELOPMENT**						
Computer Development - Small Systems	Computer Development - Small Systems	10	10	42 827 602	4 282 760	48 787 249	4 452 679
Computer Software - General	Computer Software - General	5	5	5 076 404	1 002 927	6 701 454	1 340 291
Computer Software - Communication/Operational	Computer Software - Communication/Operational	5	5	3 639 540	506 967	4 652 481	1 270 373
WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)							
	HYDRAULIC GENERATION						
	WPLP - Powerhouse Renovations		40			-	-
	WPLP - Support Building Renovations		20			-	-
	WPLP - Operational Employment Fund		95			389 662	3 791
	GENERAL EQUIPMENT						
	WPLP - Computer Equipment		5			21 228	3 325
	WPLP INTANGIBLE ASSETS						
	TRANSMISSION						
	WPLP - Transmission Development Fund		79			1 909 456	24 141
	COMMUNICATION						
	WPLP - Mobile Radio, Telephone and Conferencing		8			212 713	28 966
	WPLP - Operational Data Network		8			440 117	55 721
	EASEMENTS						
	WPLP - Easements		75			796 640	10 595

* Depreciation rates were not established in the 2010 Depreciation Study

*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.

Section:	5: Appendix 5.6 Attachment II	Page No.:	ii-5
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Changes in Depreciation Rates		

PREAMBLE TO IR (IF ANY):

GF states Amortization accounting is used for certain accounts that contain a large volume of small dollar value assets where the effort required to maintain detailed records is not warranted. Many electric utilities in North America have received approval to adopt amortization accounting for these types of accounts.

QUESTION:

Please provide a comparison between:

c) Please explain the changes in accounts subject to amortization and also the changes in amortization periods.

RATIONALE FOR QUESTION:

RESPONSE:

An explanation for the changes in accounts subject to amortization and also the changes in amortization periods are documented below:

Changes in accounts subject to amortization

Support Building Renovations (Pointe Du Bois - New)
New account for 2014 study, amortization period was set to match other Support Building Renovation accounts.

Transmission – Community Development Costs

New account established for the Wuskwatim project, amortization period was set to the weighted average service life of the related transmission assets.

Synchronous Condenser Overhauls (Substation)
Changed to the amortization method for consistency with other overhaul accounts, no change in service life.

Metering Exchanges
New component originally part of distribution, amortization period was established to reflect the cycle time of the program.

Leasehold Improvements – Sony Place
New leasehold arrangement, amortization period was set to the length of the lease.

Easements
Changed to amortization accounting since easements have no definite end date, no change in service life.

Wuskwatim Power Limited Partnership (WPLP)
New accounts for 2014 study – amortization periods consistent with similar Electric accounts.

Accounts with changes in amortization periods

Powerhouse Renovations (all generating stations)
The Powerhouse Renovations account was a new component identified during the 2010 Depreciation Study, for use on a go forward basis. The selected amortization period of 25 years was an initial estimate for expected future costs, as no actual transactions were available for analysis at the time of the 2010 Depreciation Study. During the 2014 Depreciation Study, the nature of actual charges incurred during the 2011-2014 timeframe was considered and the life expectancy was changed to 40 years to better reflect the cycle time for the types of included costs, such as roof replacements, window and door upgrades, lunchroom and washroom upgrades. Manitoba Hydro operational staff indicated that these types of upgrades are typically undertaken at 35 – 40 years, with some cycles as long as 50 years.

Community Development Costs

Community development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures. The amortization period has been updated to reflect the changes in average service life for associated physical assets.

Combustion Turbine Overhauls - Brandon Units 6 and 7

The average service life for the Combustion Turbines Account was extended from 10 to 15 years as the units have not yet reached the operating hours at which the first major overhaul is required. Since the 2010 Depreciation Study, the combustion turbines have been operated less frequently than anticipated at that time, and based on current and expected operating hours, Manitoba Hydro operational staff expect the first major overhaul to occur at approximately 15-18 years after the original installation.

Ground Line Treatment (Distribution)

The average service life for the Ground Line Treatment Account was extended from 10 to 12 years to reflect the increase of cycle time for the Ground Line Treatment program.

Section:	Tab 5: Appendix 5.6 Attachment 2	**Page No.:**	III-2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation Expenses		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file the description of the Average Service Life Methodology and explain how the approach differs from the ELG methodology described on page III-2 (provide examples if available).

RATIONALE FOR QUESTION:

To understand the difference between ELG and ASL for rate setting purposes.

RESPONSE:

For a description of the Average Service Life Methodology and explanation of how the approach differs from the ELG methodology described on page III-2 of the Gannett Fleming depreciation study please refer to Manitoba Hydro's response to PUB directives #8 and #9 from Order 43/13 as filed in Appendix 11.49, pages 7 through 11, of Manitoba Hydro's application.

Section:	5 Appendix 5.6 Schedule 1	**Page No.:**	A-10,A-11,A12
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Sustaining Capital Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please compare the retirement summarized by each interval for the experience 2001-2010 in the 2010 study on page II-12 with the 2004 – 2013 experience band in schedule A-10 of the 2014 study and comment on any differences.

RATIONALE FOR QUESTION:

To assess changes in the depreciation study from the last depreciation study.

RESPONSE:

The referenced schedules present data for an illustrative example which does not include Manitoba Hydro specific information. The schedules are identical except that the years shown in the title and in the row and column headers have all been shifted forward by three years for the example included in the 2014 study.

Section:	5 Appendix 5.6 Schedule 1	**Page No.:**	A-10,A-11,A12
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Sustaining Capital Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a similar comparison of Other Transactions in Schedule 2 with that used in the 2010 study and explain.

RATIONALE FOR QUESTION:

To assess changes in the depreciation study from the last depreciation study.

RESPONSE:

Please refer to the response to PUB/MH-I-45a.

Section:	5 Appendix 5.6 Schedule 1	**Page No.:**	A-10,A-11,A12
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Sustaining Capital Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a similar comparison for Schedule 3 plant exposed to Retirement with that used in the 2010 study and explain.

RATIONALE FOR QUESTION:

To assess changes in the depreciation study from the last depreciation study.

RESPONSE:

Please refer to the response to PUB/MH-I-45a.

Section:	Tab 5: Schedule 5.1.6 Appendix 5.6 pg.7	**Page No.:**	7
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Depreciation Rate Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the depreciable group table to include two additional columns including Previous Expected Life, and Change in Expected Life.

RATIONALE FOR QUESTION:

To assess changes in the depreciation study from the last depreciation study.

RESPONSE:

Please see the attached depreciable group table for the additional columns including Previous Expected Life and Change in Expected Life.

Depreciation Rate Tables (Electric operations)

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
HYDRAULIC GENERATION			
GREAT FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
POINTE DU BOIS - Original			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
POINTE DU BOIS - New			
DAMS, DYKES AND WEIRS		125	New
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS		65	New
ROADS AND SITE IMPROVEMENTS		50	New
A/C ELECTRICAL POWER SYSTEMS		55	New
INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25	New
AUXILIARY STATION PROCESSES		50	New
SUPPORT BUILDINGS		65	New
SUPPORT BUILDING RENOVATIONS		20	New
SEVEN SISTERS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
SLAVE FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
PINE FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
COMMUNITY DEVELOPMENT COSTS	81	78	(3)
MCARTHUR FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
KELSEY			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
GRAND RAPIDS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
COMMUNITY DEVELOPMENT COSTS ***	80	79	(1)
KETTLE			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
LAURIE RIVER			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
JENPEG			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
LAKE WINNIPEG REGULATION			
DAMS, DYKES AND WEIRS	125	125	-
LICENCE RENEWAL	50	50	-
COMMUNITY DEVELOPMENT COSTS	100	85	(15)
CHURCHILL RIVER DIVERSION			
DAMS, DYKES AND WEIRS	125	125	-
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
COMMUNITY DEVELOPMENT COSTS	100	90	(10)

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
LONG SPRUCE			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
LIMESTONE			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
WUSKWATIM			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
INFRASTRUCTURE SUPPORTING GENERATION			
PROVINCIAL ROADS	50	50	-
TOWN SITE BUILDING	65	55	(10)
TOWN SITE BUILDINGS RENOVATIONS	20	20	-
TOWN SITE OTHER INFRASTRUCTURE	45	45	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
THERMAL GENERATION			
BRANDON UNIT 5 (COAL)			
POWERHOUSE	65	75	10
POWERHOUSE RENOVATIONS	25	40	15
ROADS AND SITE IMPROVEMENTS	50	50	-
THERMAL TURBINES AND GENERATORS	50	60	10
GOVERNORS AND EXCITATION SYSTEM	50	50	-
STEAM GENERATOR AND AUXILIARIES	65	60	(5)
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
BRANDON UNITS 6 AND 7			
POWERHOUSE	65	75	10
POWERHOUSE RENOVATIONS	25	40	15
THERMAL TURBINES AND GENERATORS	50	60	10
GOVERNORS AND EXCITATION SYSTEM	50	50	-
COMBUSTION TURBINE	25	25	-
LICENCE RENEWAL	50	50	-
COMBUSTION TURBINE OVERHAULS	10	15	5
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SELKIRK			
POWERHOUSE	65	75	10
POWERHOUSE RENOVATIONS	25	40	15
ROADS AND SITE IMPROVEMENTS	50	50	-
THERMAL TURBINES AND GENERATORS	50	60	10
GOVERNORS AND EXCITATION SYSTEM	50	50	-
STEAM GENERATOR AND AUXILIARIES	65	60	(5)
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
DIESEL GENERATION			
BUILDINGS	30	25	(5)
BUILDING RENOVATIONS	15	15	-
ENGINES AND GENERATORS - OVERHAULS	5	4	(1)
ENGINES AND GENERATORS	25	22	(3)
ACCESSORY STATION EQUIPMENT	20	20	-
FUEL STORAGE AND HANDLING	30	25	(5)
TRANSMISSION			
ROADS, TRAILS AND BRIDGES	45	50	5
METAL TOWERS AND CONCRETE POLES	85	85	-
POLES AND FIXTURES	55	55	-
GROUND LINE TREATMENT	10	10	-
OVERHEAD CONDUCTOR AND DEVICES	65	80	15
UNDERGROUND CABLE AND DEVICES	45	45	-
COMMUNITY DEVELOPMENT COSTS		79	New
SUBSTATIONS			
BUILDINGS	65	65	-
BUILDING RENOVATIONS	20	20	-
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	50	-
POLES AND FIXTURES	40	45	5
POWER TRANSFORMERS	50	50	-
OTHER TRANSFORMERS	35	50	15
INTERRUPTING EQUIPMENT	45	50	5
OTHER STATION EQUIPMENT	43	45	2
ELECTRONIC EQUIPMENT AND BATTERIES	20	25	5
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	65	65	-
SYNCHRONOUS CONDENSER OVERHAULS	15	15	-
HVDC CONVERTER EQUIPMENT	25	30	5
HVDC SERIALIZED EQUIPMENT	25	30	5
HVDC ACCESSORY STATION EQUIPMENT	37	36	(1)
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	20	25	5
DISTRIBUTION			
CONCRETE DUCTLINE AND MANHOLES	75	75	-
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENTS	50	30	(20)
METAL TOWERS	50	60	10
POLES AND FIXTURES	55	65	10
GROUND LINE TREATMENT	10	12	2
OVERHEAD CONDUCTOR AND DEVICES	60	60	-
UNDERGROUND CABLE AND DEVICES - 66 KV	70	60	(10)
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	60	-
UNDERGROUND CABLE AND DEVICES - SECONDARY	45	44	(1)
SERIALIZED EQUIPMENT - OVERHEAD	35	45	10
DSC - HIGH VOLTAGE TRANSFORMERS	50	50	-
SERIALIZED EQUIPMENT - UNDERGROUND	40	42	2
ELECTRONIC EQUIPMENT	10	10	-
SERVICES	30	35	5
STREET LIGHTING	35	45	10

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
METERS			
METERS - ELECTRONIC	20	15	(5)
METERS - ANALOG	25	26	1
METERING EXCHANGES		15	New
METERING TRANSFORMERS	40	50	10
COMMUNICATION			
BUILDINGS	65	65	-
BUILDING RENOVATIONS	20	20	-
BUILDING - SYSTEM CONTROL CENTRE	65	75	10
COMMUNICATION TOWERS	60	60	-
FIBRE OPTIC AND METALLIC CABLE	35	35	-
CARRIER EQUIPMENT	15	20	5
OPERATIONAL IT EQUIPMENT	5	5	-
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8	8	-
OPERATIONAL DATA NETWORK	8	8	-
POWER SYSTEM CONTROL	10	15	5
MOTOR VEHICLES			
PASSENGER VEHICLES	9	11	2
LIGHT TRUCKS	10	12	2
HEAVY TRUCKS	15	19	4
CONSTRUCTION EQUIPMENT	15	23	8
LARGE SOFT-TRACK EQUIPMENT	22	27	5
TRAILERS	35	35	-
MISCELLANEOUS VEHICLES	10	13	3
BUILDINGS			
BUILDINGS - GENERAL	65	65	-
BUILDING RENOVATIONS	20	20	-
BUILDING - 360 PORTAGE - CIVIL	100	100	-
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	45	-
LEASEHOLD IMPROVEMENTS - SONY PLACE		10	New
GENERAL EQUIPMENT			
TOOLS, SHOP AND GARAGE EQUIPMENT	15	15	-
COMPUTER EQUIPMENT	5	5	-
OFFICE FURNITURE AND EQUIPMENT	20	20	-
HOT WATER TANKS	6	6	-
EASEMENTS			
EASEMENTS	75	75	-
COMPUTER SOFTWARE AND DEVELOPMENT			
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	10	11	1
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10	-
COMPUTER SOFTWARE - GENERAL	5	5	-
COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	5	5	-
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	6	7	1

Section:	Tab 5: Schedule 5.1.6 Appendix 5.6 pg.7	**Page No.:**	7
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Depreciation Rate Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please recast depreciation and amortization expense schedule 5.1.6 assuming the continuation of ASL rates for 2015/16 and 2016/17 and provide a comparison with the applied for ELG depreciation expense rates for those years.

RATIONALE FOR QUESTION:

To assess changes in the depreciation study from the last depreciation study.

RESPONSE:

The following tables provide:

- A version of Schedule 5.1.6 assuming the continuation of the 2014/15 ASL depreciation rates, which includes a provision for negative salvage, for the 2015/16 and 2016/17 fiscal years. Please note that the ASL figures presented for 2015/16 and 2016/17 are not IFRS compliant.

- 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 a continuation of the 2014/15 ASL depreciation rates. This comparison demonstrates that the applied for ELG depreciation rates result in a lower overall depreciation expense of approximately $24 million for 2015/16 and $27 million for 2016/17.

MANITOBA HYDRO PUB/MH I-46b
DEPRECIATION AND AMORTIZATION EXPENSE (000's)
SCHEDULE 5.1.6 ASSUMING THE CONTINUATION OF 2014/15 ASL DEPRECIATION RATES

	2012/13 Actual	2013/14 Actual	2014/15 Forecast ASL	2015/16 Forecast ASL *	2016/17 Forecast ASL *
Generation					
Hydraulic Generating Stations	80,110	82,678	92,953	96,737	101,413
Thermal Generating Stations	15,415	15,562	15,770	15,912	16,013
Demand Side Management	28,217	30,262	31,576	34,957	37,501
Diesel Generating Stations	1,457	1,757	2,342	2,455	2,009
Wuskwatim	16,179	26,688	26,651	26,898	26,996
Amortization of Contributions	(841)	(868)	(1,049)	(1,146)	(1,146)
	$ 140,537	$ 156,079	$ 168,244	$ 175,813	$ 182,786
Transmission					
Transmission	14,571	16,644	15,929	16,386	17,644
Amortization of Contributions	(1,358)	(3,204)	(3,051)	(3,054)	(3,059)
	$ 13,213	$ 13,440	$ 12,879	$ 13,332	$ 14,585
Stations					
Substations	82,493	86,122	87,617	95,463	100,197
Transformers	1,806	1,940	1,627	1,996	2,333
Amortization of Contributions	(1,247)	(4,457)	(4,402)	(4,402)	(4,402)
	$ 83,052	$ 83,605	$ 84,842	$ 93,057	$ 98,128
Distribution					
Subtransmission Lines	6,271	6,629	7,376	8,126	8,608
Distribution Lines	58,170	61,337	60,509	64,210	68,449
Meters & Transformers	4,273	4,260	2,848	2,974	3,072
Amortization of Contributions	(5,084)	(5,476)	(5,699)	(6,397)	(6,990)
	$ 63,630	$ 66,750	$ 65,034	$ 68,913	$ 73,139
Other					
Communications	19,192	21,307	16,819	17,352	17,601
Motor Vehicles	10,954	11,573	10,154	10,852	11,265
Structures & Improvements	7,947	8,066	7,928	8,551	9,297
General Equipment	25,806	23,255	16,627	16,780	16,796
Computer Development	20,582	19,667	17,687	18,267	20,566
Conawapa	-	-	-	-	7,711
Affordable Energy Fund	5,406	4,410	5,270	4,290	1,509
Miscellaneous	3,550	4,628	1,701	2,840	3,455
Corporate Allocation	(1,946)	(1,946)	(1,974)	(2,039)	(2,040)
Target Adjustment	-	-	(621)	(3,008)	(5,316)
	$ 91,491	$ 90,960	$ 73,591	$ 73,886	$ 80,844
Total D & A Expense Including Accounting Changes	$ 391,923	$ 410,834	$ 404,590	$ 425,001	$ 449,482

* The ASL figures presented for 2015/16 & 2016/17 are not IFRS compliant

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
COMPARISON OF ELG AND ASL

PUB/MH I-46b
(000's)

	Schedule 5.1.6		Continuation of ASL Rates		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	96,737	101,413	(4,472)	(5,372)
Thermal Generating Stations	15,755	15,856	15,912	16,013	(157)	(157)
Demand Side Management	34,957	37,501	34,957	37,501	0	0
Diesel Generating Stations	2,557	2,111	2,455	2,009	102	102
Wuskwatim	26,984	27,082	26,898	26,996	86	86
Amortization of Contributions	(1,146)	(1,146)	(1,146)	(1,146)	(0)	(0)
	$ 171,373	$ 177,446	$ 175,813	$ 182,786	$ (4,440)	$ (5,340)
Transmission						
Transmission	13,369	14,367	16,386	17,644	(3,017)	(3,277)
Amortization of Contributions	(3,054)	(3,059)	(3,054)	(3,059)	(0)	(0)
	$ 10,315	$ 11,308	$ 13,332	$ 14,585	$ (3,017)	$ (3,277)
Stations						
Substations	85,735	90,177	95,463	100,197	(9,728)	(10,020)
Transformers	1,597	1,828	1,996	2,333	(399)	(505)
Amortization of Contributions	(4,402)	(4,402)	(4,402)	(4,402)	0	0
	$ 82,930	$ 87,603	$ 93,057	$ 98,128	$ (10,127)	$ (10,525)
Distribution						
Subtransmission Lines	6,948	7,401	8,126	8,608	(1,178)	(1,207)
Distribution Lines	56,989	60,951	64,210	68,449	(7,221)	(7,498)
Meters & Transformers	3,281	3,404	2,974	3,072	307	332
Amortization of Contributions	(6,409)	(7,009)	(6,397)	(6,990)	(12)	(19)
	$ 60,809	$ 64,747	$ 68,913	$ 73,139	$ (8,104)	$ (8,392)
Other						
Communications	17,765	18,206	17,352	17,601	413	605
Motor Vehicles	11,819	12,226	10,852	11,265	967	961
Structures & Improvements	8,800	9,557	8,551	9,297	249	260
General Equipment	16,780	16,797	16,780	16,796	0	1
Computer Development	18,487	20,816	18,267	20,566	220	250
Conawapa	-	7,711	-	7,711	-	0
Affordable Energy Fund	4,290	1,509	4,290	1,509	0	(0)
Miscellaneous	2,652	3,269	2,840	3,455	(188)	(186)
Corporate Allocation	(1,850)	(1,853)	(2,039)	(2,040)	189	187
Target Adjustment	(3,305)	(6,938)	(3,008)	(5,316)	(297)	(1,622)
	$ 75,439	$ 81,300	$ 73,886	$ 80,844	$ 1,554	$ 456
Total D & A Expense Including Accounting Changes	$ 400,866	$ 422,404	$ 425,000	$ 449,482	$ (24,134)	$ (27,078)

* The ASL figures presented for 2015/16 & 2016/17 are not IFRS compliant

Section:	6	**Page No.:**	5 of 21
Topic:	Bill Impacts		
Subtopic:	Diesel Rates		
Issue:	Rates Paid by Diesel Community Customers.		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is applying for diesel rate increases, and notes in Chapter 11 of its Application that prior interim orders with respect to diesel rates cannot yet be finalized.

QUESTION:

Please file an update of the status of alternatives to diesel generation that Manitoba Hydro is still considering and the timeline that is currently planned for such initiatives.

RATIONALE FOR QUESTION:

Manitoba Hydro has provided an update on the status of rates in the diesel communities and progress towards alternative energy and an eventual grid connections. This Information Request seeks more detail with respect to that issue.

RESPONSE:

Since 2013, efforts with respect to alternatives to diesel generation have focused on a joint initiative of Manitoba Hydro, the Province of Manitoba and Aboriginal Affairs and Northern Development Canada (AANDC) ("The Parties") working together to seek solutions to reduce diesel fuel usage in the four off-grid communities. The focus of this approach has been to seek solutions from the marketplace by issuing a Request for Information (RFI).

Following meetings with leadership of the four off-grid communities in spring 2013, they indicated their support for The Parties issuing a RFI to seek technically feasible and economically viable renewable energy technology solutions for reducing diesel fuel usage for electric power generation and space heating purposes.

The Parties issued the RFI in Fall 2013 resulting in a number of information packages being received. Based on the information received, options to reduce diesel fuel for electricity generation were explored further. Specifically, solar photovoltaic and/or wind / diesel hybrid generation systems with energy storage were judged as having the potential to achieve the reliability and operational and maintenance simplicity required for a remote setting. Three organizations that provided a submission under the RFI were engaged to conduct business cases of solar, wind and storage technologies to reduce diesel fuel usage for electricity generation in each of the off-grid communities. That work commenced in June 2014 and included site visits to each off-grid community in July 2014. The organizations concluded their work in Fall 2014. Currently, The Parties are continuing to review the information to determine the viability of a potential future project. A project proceeding and timing of same is dependent on funding availability and community acceptance. Discussions with communities have taken place throughout this process.

Section:	6	**Page No.:**	5 of 21
Topic:	Bill Impacts		
Subtopic:	Diesel Rates		
Issue:	Rates Paid by Diesel Community Customers.		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is applying for diesel rate increases, and notes in Chapter 11 of its Application that prior interim orders with respect to diesel rates cannot yet be finalized.

QUESTION:

Please provide an update to the programs Manitoba Hydro identified in response to PUB/MH I-150(a) of the 2012/13 and 2013/14 GRA.

RATIONALE FOR QUESTION:

Manitoba Hydro has provided an update on the status of rates in the diesel communities and progress towards alternative energy and an eventual grid connections. This Information Request seeks more detail with respect to that issue.

RESPONSE:

As noted in the response to PUB-MH-I-47a, current efforts to seek alternatives to diesel generation have focused on efforts undertaken by Manitoba Hydro, the Province of Manitoba and Aboriginal Affairs and Northern Development Canada (AANDC) working together to seek solutions to reduce diesel fuel consumption in the off-grid communities. Available updates on items noted in the response to PUB/MH-I-150a from the 2012/13 and 2013/14 GRA are as follows:

Green Pilot: Manitoba Hydro's Bioenergy Optimization Program, funded in part by the federal Clean Energy Fund included a remote community component. This component of work involved simulating conditions representative of a remote northern community at the biomass gasification and combined heat power system located at Pineland Forest Nursery in eastern Manitoba. To simulate the conditions, modifications were made to the char-ash handling system to allow longer run times without operator intervention. Small-diameter spruce trees were harvested to provide a representative feedstock of northern communities and an operator with no prior experience in renewable energy systems was hired and trained to operate the system. The findings of the demonstration do not support implementing this technology in an off-grid community at this time due to reliability, operation and maintenance requirements. Cold weather performance issues that must be addressed prior to deploying this technology in an off-grid community will require further research and testing. Additional short-term testing of this system in collaboration with Natural Resources Canada (NRCan) and Prairie Agricultural Machinery Institute (PAMI) is currently underway

Collaborative Efforts with Other Jurisdictions: Manitoba Hydro continues to collaborate with other utilities and share information via its membership in the Canadian Off-Grid Utility Association (COGUA). Through its membership in the Centre for Energy Advancement through Technological Innovation (CEATI) International Inc., Manitoba Hydro also shares information with other utilities and research organizations with respect to diesel alternatives in off-grid locations.

Shamattawa grid line analysis: The working group process with representation from Manitoba Hydro, Shamattawa the Province of Manitoba and AANDC to review the costs and benefits associated with a land line to the community is still in place and work is ongoing. The intent of this process is to incorporate input from all parties' in the event that a future funding opportunity arises for the significant capital requirement associated with a land line connection.

Liquefied Natural Gas: Manitoba Hydro continues to explore feasibility of LNG. Based on preliminary explorations, it does not appear to be economically viable to replace diesel with LNG in the off-grid communities.

First Nations Power Smart Program: Manitoba Hydro has initiated a two channel targeted approach allowing First Nation Communities to improve the energy efficiency and home quality comfort of their homes, reduce energy bills, and provide employment and training opportunities for members in the community. A dedicated First Nations Energy Advisor works directly with First Nation Communities to increase energy efficiency. The Insulation channel provides free basic energy efficiency measures such as LEDs, showerheads, pipe wrap, window kits and draft stoppers and free insulation upgrades for qualifying homes. The

Direct Install channel, which launched in the fall of 2014, provides basic energy efficient upgrades to qualifying homes to increase energy efficiency and conserve water. To date, 129 eligible homes have received insulation and basic energy efficient upgrades in Brochet, Lac Brochet and Tadoule Lake. It is estimated that a further 75 homes may be eligible for insulation upgrades in Shamattawa. In the four remote diesel communities, it is estimated 440 homes may be eligible for the Direct Install of basic energy efficiency measures. The timeline for completion of these free upgrades is dependent on each individual First Nation Communities' schedule. Please also see Manitoba Hydro's response to MKO/COALITION-I-1a.

To assist the four diesel communities in identifying potential energy efficiency upgrades, Manitoba Hydro completed walk-through energy reviews for all non-residential buildings. The greatest opportunity for electricity savings in commercial buildings in these communities is through upgrading lighting systems. Manitoba Hydro shared the results of the walk-through energy reviews with the communities. Since then three commercial lighting upgrade projects have been undertaken in two communities and one potential project is currently underway. Manitoba Hydro continues to provide assistance and program support based upon the communities' project timelines and interest.

Section:	6	**Page No.:**	5 of 21
Topic:	Bill Impacts		
Subtopic:	Diesel Rates		
Issue:	Rates Paid by Diesel Community Customers.		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is applying for diesel rate increases, and notes in Chapter 11 of its Application that prior interim orders with respect to diesel rates cannot yet be finalized.

QUESTION:

Please provide an analysis for each of the four diesel communities for the past five years in terms of fixed costs, variable non-fuel costs, fuel purchase costs, and fuel transport costs.

RATIONALE FOR QUESTION:

Manitoba Hydro has provided an update on the status of rates in the diesel communities and progress towards alternative energy and an eventual grid connections. This Information Request seeks more detail with respect to that issue.

RESPONSE:

The table below provides a breakdown by community of fuel hauling costs (including fuel purchases and transport costs) as well as variable non-fuel costs. The total revenue deficiency of $4.7 million for the past five years (defined as the difference between revenue and total direct costs) has also been provided.

	2010	2011	2012	2013	2014
Diesel Zone Revenue	4,641,932	4,919,545	6,070,284	6,549,186	6,577,615
Brochet Fuel Hauling	784,715	777,144	1,011,141	1,271,972	1,110,455
Brochet Variable Non-fuel	519,219	607,318	431,759	512,316	492,158
Lac Brochet Fuel Hauling	1,128,180	977,769	1,236,189	1,318,178	1,357,539
Lac Brochet Variable Non-fuel	429,558	524,459	483,008	410,960	612,762
Shamattawa Fuel Hauling	1,229,877	1,365,493	1,687,945	1,478,411	1,703,559
Shamattawa Variable Non-fuel	526,965	582,391	576,926	707,286	880,037
Tadoule Fuel Hauling	727,839	804,380	933,757	1,018,733	766,966
Tadoule Variable Non-fuel	436,520	451,711	512,653	492,701	602,287
	5,782,872	6,090,665	6,873,378	7,210,556	7,525,763
Total Revenue Deficiency	(1,140,941)	(1,171,120)	(803,095)	(661,370)	(948,148)

The Revenue Deficiency in the table above excludes the fixed cost components. The fixed cost component in the Diesel Zone is determined based on 'total capital employed' in the Diesel Communities and is to be funded largely by customer contributions in accordance with the Settlement Agreement. Customer contributions received have been insufficient to support the ongoing capital activity. Both Diesel Zone direct costs and capital not fully funded through rate revenue and customer contributions are ultimately recovered through grid rates.

Section:	6	**Page No.:**	5 of 21
Topic:	Bill Impacts		
Subtopic:	Diesel Rates		
Issue:	Rates Paid by Diesel Community Customers.		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is applying for diesel rate increases, and notes in Chapter 11 of its Application that prior interim orders with respect to diesel rates cannot yet be finalized.

QUESTION:

Please advise what portion of the capital costs remains outstanding following receipt, by Manitoba Hydro, of the AANDC cheques identified in Chapter 10, Page 9 of Manitoba Hydro's application.

RATIONALE FOR QUESTION:

Manitoba Hydro has provided an update on the status of rates in the diesel communities and progress towards alternative energy and an eventual grid connections. This Information Request seeks more detail with respect to that issue.

RESPONSE:

In Order 33/15 the PUB determined that examination of issues related to the diesel communities and the Settlement Agreement should be examined after the Settlement Agreement has been filed.

Section:	6	**Page No.:**	5 of 21
Topic:	Bill Impacts		
Subtopic:	Diesel Rates		
Issue:	Rates Paid by Diesel Community Customers.		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is applying for diesel rate increases, and notes in Chapter 11 of its Application that prior interim orders with respect to diesel rates cannot yet be finalized.

QUESTION:

Please refile an update to re PUB/MH I-150(d) of the 2012/13 and 2013/14 GRA.

RATIONALE FOR QUESTION:

Manitoba Hydro has provided an update on the status of rates in the diesel communities and progress towards alternative energy and an eventual grid connections. This Information Request seeks more detail with respect to that issue.

RESPONSE:

The following table has been updated and presents actual electricity consumption by year for each of the North-Central communities.

	Total GW.h	A GW.h	B GW.h	C GW.h	D GW.h	E GW.h	F GW.h	G GW.h
1992/93	19.0	3.6	3.1	0.9	1.2	3.7	4.8	1.9
1993/94	20.5	3.6	3.2	1.0	1.3	4.0	5.3	2.1
1994/95	21.5	3.7	3.4	1.0	1.4	4.2	5.7	2.2
1995/96	23.4	3.6	3.9	1.1	1.8	4.6	5.9	2.4
1996/97	25.0	4.2	4.2	1.4	1.9	4.7	6.1	2.4
1997/98	29.6	6.1	5.3	2.0	1.9	5.0	6.6	2.8
1998/99	36.3	6.6	9.1	3.4	1.9	5.1	7.1	3.0
1999/00	47.1	9.4	10.4	4.3	3.0	7.6	9.2	3.4
2000/01	58.4	10.7	11.5	5.2	3.8	9.5	13.5	4.3
2001/02	69.1	14.0	12.1	5.3	4.4	10.6	16.7	5.9
2002/03	77.4	12.0	14.3	6.1	4.9	12.6	20.1	7.6
2003/04	78.9	14.5	13.6	5.6	5.5	13.0	19.5	7.3
2004/05	91.3	17.2	15.4	6.6	6.6	16.1	21.2	8.3
2005/06	88.2	16.5	14.8	6.2	6.4	15.2	20.8	8.3
2006/07est	92.6	18.4	15.2	6.4	6.6	17.0	20.4	8.7
2007/08	97.1	20.4	15.6	6.7	6.8	18.7	19.9	9.0
2008/09	100.6	21.1	15.1	6.7	6.9	19.7	21.6	9.5
2009/10	97.5	20.1	14.8	6.9	6.7	18.9	20.9	9.2
2010/11	104.9	19.8	15.7	7.6	7.0	23.7	20.7	10.4
2011/12	106.1	20.1	15.7	7.3	7.7	23.9	20.9	10.5
2012/13	110.6	20.6	15.7	7.6	8.5	25.2	21.7	11.3
2013/14	123.5	23.6	17.1	8.4	9.3	28.5	23.7	12.9

A = Oxford House
B = God's Lake Narrows
C = God's River
D = Red Sucker Lake
E = St. Theresa Point
F = Garden Hill
G = Wasagamack

Section:	6	**Page No.:**	5 of 21
Topic:	Bill Impacts		
Subtopic:	Diesel Rates		
Issue:	Rates Paid by Diesel Community Customers.		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is applying for diesel rate increases, and notes in Chapter 11 of its Application that prior interim orders with respect to diesel rates cannot yet be finalized.

QUESTION:

Assuming the original settlement agreement is permanently lost and will not resurface, what steps does Manitoba Hydro propose to allow the finalization of the various interim diesel rate orders?

RATIONALE FOR QUESTION:

Manitoba Hydro has provided an update on the status of rates in the diesel communities and progress towards alternative energy and an eventual grid connections. This Information Request seeks more detail with respect to that issue.

RESPONSE:

For a complete summary of the history and current status of the diesel Settlement Agreement, please see Manitoba Hydro's response to Directive 3 from Order 134/10 on page 8 of TAB 10.

In short, despite the Settlement Agreement not being finalized and executed, the Parties proceeded on a good faith basis to implement the terms of Settlement. All obligations under the Settlement Agreement have been satisfied. The Settlement Agreement was subsequently executed; however, portions of the original signed Agreement and/or Schedules thereto which were executed by the First Nations were lost or misplaced. Arrangements were made to obtain documentation to verify the missing portions of the Agreement and/or Schedules. Manitoba Hydro understands this documentation is in the possession of MKO.

During the 2012/13 & 2013/14 GRA, Manitoba Hydro informed the PUB that AANDC advised that a compensation issue had arisen between AANDC and MKO, which did not involve Manitoba Hydro. Manitoba Hydro is not privy to the details of this dispute but understands that MKO will not be providing a true copy of the Settlement Agreement until it is resolved. AANDC has indicated that as of December 2014, there has been no change in circumstances and MKO has not yet provided the true copies of the Settlement Agreement.

Manitoba Hydro received payments from MKO (on behalf of the four Diesel First Nations) pursuant to the terms of the Minutes of Settlement. MKO imposed conditions upon Manitoba Hydro including that the payments would be returned if the Minutes of Settlement were not ratified by the parties by way of execution of a Settlement Agreement. Theoretically, if monies were returned, the rate relief occasioned by those monies by virtue of the interim orders would also have to be reversed. Manitoba Hydro has to date attempted to be patient in waiting for the dispute between MKO and AANDC to be resolved so as to avoid creating additional unnecessary disputes related the significance of production of a true copy of the agreement as it relates to the condition imposed by MKO.

Manitoba Hydro is seeking a legal opinion as to what options are available in the circumstances.

Section:	Tab 6, App. 6.7	**Page No.:**	
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Surplus Energy Program: Revised Terms & Conditions – Option 1		
Issue:	Increased Off-Peak Sales		

PREAMBLE TO IR (IF ANY):

MH has modified Option 1, Terms and Conditions, to allow separate Time of Use (peak/shoulder/off-peak) designations for SEP

QUESTION:

Provide load profiles for current SEP customers and potential SEP Option 1 customers.

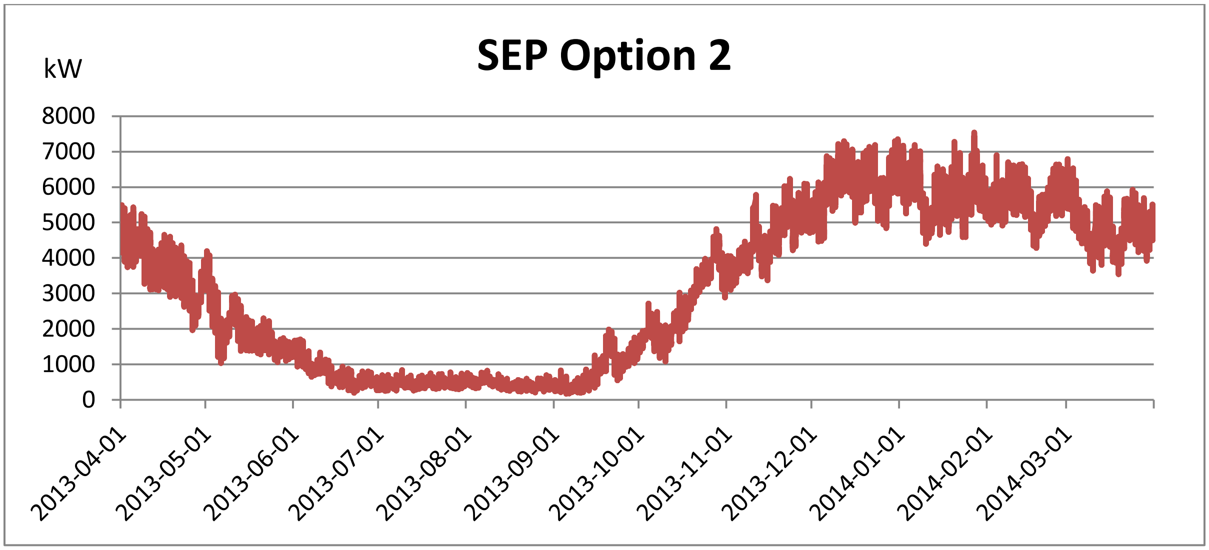
RATIONALE FOR QUESTION:

To determine the impacts of proposed revisions on revenue requirement.

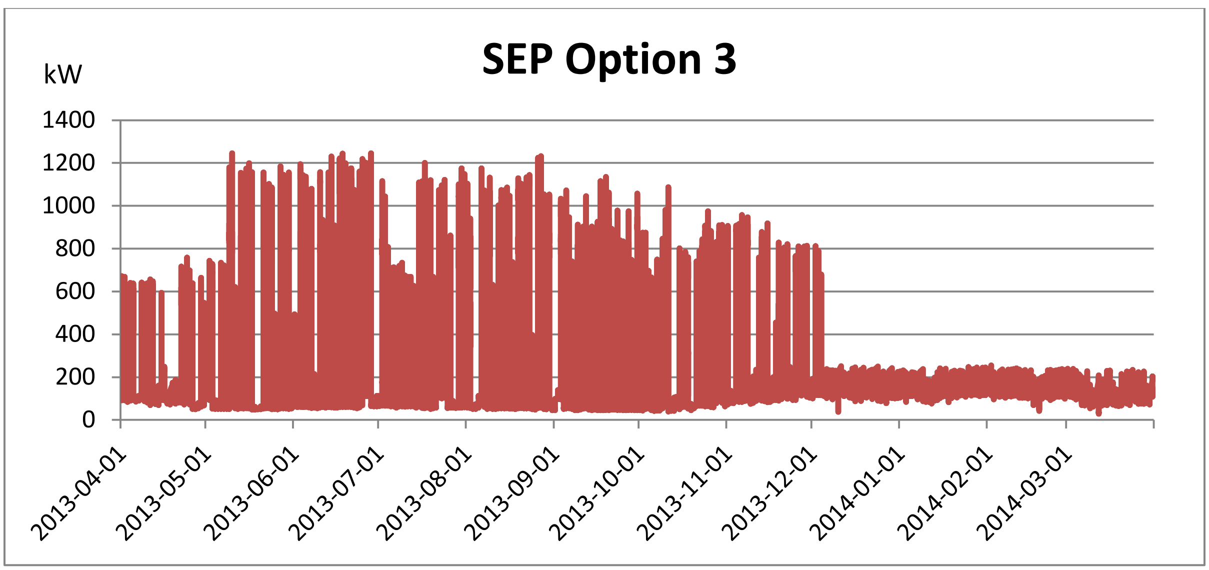
RESPONSE:

Please see the charts in this response for the load profiles for customers served under SEP Options 2 and 3 for the 2013/14 fiscal year. No customers have currently expressed an interest in subscribing for SEP Option 1, therefore it is not possible for Manitoba Hydro to provide potential customer load profiles defining time-of-use energy usage under that Option.

Load Profile for SEP Option 2 Customers:



Load Profile for SEP Option 3 Customers:



Section:	Tab 6, App. 6.7	**Page No.:**	
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Surplus Energy Program: Revised Terms & Conditions – Option 1		
Issue:	Increased Off-Peak Sales		

PREAMBLE TO IR (IF ANY):

MH has modified Option 1, Terms and Conditions, to allow separate Time of Use (peak/shoulder/off-peak) designations for SEP

QUESTION:

Provide examples of how an Option 1 customer would incur an additional demand charge by nominating higher or lower demand reference levels for shoulder or off-peak.

RATIONALE FOR QUESTION:

To determine the impacts of proposed revisions on revenue requirement.

RESPONSE:

SEP Option 1 customers are required to nominate both their Reference Level of Demand (which is the level of demand that is to be considered firm load) and their Total Demand (which is the combination of firm load plus SEP load). Manitoba Hydro is proposing to allow customers on SEP Option 1 to designate a different Reference Demand for each of the three pricing periods. The highest designated Reference Demand will be used in determining the customer's monthly billing demand.

For example, assume a customer has a Total Demand of 30,000 kV.A and sets the following Reference Levels of Demand

On-peak:	24,000
Shoulder:	25,000
Off-Peak:	22,500
Maximum:	25,000

If the customer's actual recorded monthly demand falls between the maximum Reference Demand (in this case 25,000 kV.A) and the Total Demand (30,000 kV.A), the customer will be billed based on the maximum Reference Demand of 25,000 kV.A.

If the customer's actual recorded demand for the month was 23,000 kV.A, the customer would be billed for 23,000 kV.A as it is lower than both the maximum Reference Demand and the Total Demand.

The customer will pay a demand charge greater than their highest Reference Demand only if their actual monthly recorded demand exceeds their Total Demand. Using the same example as above (Total Demand 30,000 kV.A and highest Reference Demand 25,000 kV.A), a customer whose recorded demand exceeds 30,000 kV.A (31,000 kV.A for example) would be billed 26,000 kV.A, which is the 25,000 kV.A Reference Demand plus the 1,000 kV.A that exceeded their Total Demand.

Section:	Appendix 6.3	Page No.:	21 of 25
Topic:	Bill Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

Explain how Manitoba Hydro arrived at these proposed rates and provide the detailed calculations.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

The table on the following page provides the supporting calculations for the proposed LED rates. Manitoba Hydro derived the proposed LED rates by determining the annual kilowatt hour savings expected to be achieved by converting from HPS lighting to LED and then determining the monthly cost savings using the Area and Roadway Lighting energy charge from Manitoba Hydro's 2013 Prospective Cost of Service Study (PCOSS13) updated to reflect the actual rate increases for September 1, 2012, May 1, 2013 and May 1, 2014, plus the proposed rate increase of 3.95% for April 1, 2015. The monthly cost savings were then deducted from the proposed April 1, 2015 HPS rates to determine the proposed LED rates.

In June 2014 Manitoba Hydro had filed an application requesting approval of nine LED rates. Those rates were approved by the PUB in Order 79/14 to be effective August 1, 2014. It should be noted however that the LED rate descriptions provided at that time are not the same as those proposed for LED lights under Tariff 2015-80.

At the time of the June 2014 application Manitoba Hydro had not yet secured a supplier for its LED lighting inventory therefore the LED naming convention and associated applicable wattages were based on those used in the LED street lighting pilot project. Manitoba Hydro has since secured a supplier for its inventory of LED lights. Each light specifies a "nominal" wattage (wattage shown on the packaging) and its associated energy usage. The nominal and associated energy usages for the new lights do not correlate precisely to the nominal and associated energy usage of the lights used in the pilot project because different lighting manufacturers designate different wattages to their particular LED lights.

For example, one manufacturer may state that their nominal 60 W LED light uses 54 watts, whereas another manufacturer may state that their nominal 60 W LED uses 73 watts. Since the wattages can vary from manufacturer to manufacturer, Manitoba Hydro is electing to specify ranges for each type of LED light, which have been identified in the rate schedules based on their nominal wattage. Therefore in Tariff 2015-80, a 60 W LED will have a range of greater than 50 watts up to 80 watts.

It should be further noted that at the time of the 2014 LED rate application, it was assumed a 60 W LED would replace a 70 W HPS, an 80 W LED would replace a 100 W HPS and so on. However, in practice, Manitoba Hydro is following a different replacement approach, as indicated in the table attached below.

PROPOSED APRIL 2015 RATES

NEW RATE NAME		HPS Category	HPS Wattage	LED Wattage	LED Wattage Range	Wattage Savings	kW Savings	Annual Hours	Annual kWh Savings	Energy Rate	Annual Energy Savings	Per Month Savings	Proposed Monthly HPS Rate	Proposed Monthly LED Rate
10 LED (20w CF Equivalent)	Exclusive	20 W CF	20	10	1 - 30	10.0	0.010	4252	42.5	$ 0.05496	$2.34	$ 0.19	$ 2.21	$ 2.02
40 LED (70w HPS Equivalent)	Shared	70	97	40	>30 - 50	57.0	0.057	4252	242.4	$ 0.05496	$13.32	$ 1.11	$ 7.90	$ 6.79
40 LED (70w HPS Equivalent)	Exclusive	70	97	40	>30 - 50	57.0	0.057	4252	242.4	$ 0.05496	$13.32	$ 1.11	$ 12.97	$ 11.86
40 24 hrs LED (70w 24 hrs HPS Equiv)	Exclusive	70	97	40	>30 - 50	57.0	0.057	4252	242.4	$ 0.05496	$13.32	$ 1.11	$ 14.58	$ 13.47
60 LED (100w HPS Equivalent)	Shared	100	135	70	>50 - 80	65.0	0.065	4252	276.4	$ 0.05496	$15.19	$ 1.27	$ 8.20	$ 6.93
60 LED (100w HPS Equivalent)	Exclusive	100	135	70	>50 - 80	65.0	0.065	4252	276.4	$ 0.05496	$15.19	$ 1.27	$ 13.68	$ 12.41
90 LED (150w HPS Equivalent)	Shared	150	190	100	>80 - 120	90.0	0.090	4252	382.7	$ 0.05496	$21.03	$ 1.75	$ 10.05	$ 8.30
90 LED (150w HPS Equivalent)	Exclusive	150	190	100	>80 - 120	90.0	0.090	4252	382.7	$ 0.05496	$21.03	$ 1.75	$ 15.45	$ 13.70
150 LED (250w HPS Equivalent)	Shared	250	300	150	>120 - 180	150.0	0.150	4252	637.8	$ 0.05496	$35.05	$ 2.92	$ 12.81	$ 9.89
150 LED (250w HPS Equivalent)	Exclusive	250	300	150	>120 - 180	150.0	0.150	4252	637.8	$ 0.05496	$35.05	$ 2.92	$ 17.81	$ 14.89
250 LED (400w HPS Equivalent)	Shared	400	470	230	>180 - 280	240.0	0.240	4252	1,020.5	$ 0.05496	$56.09	$ 4.67	$ 14.70	$ 10.03
250 LED (400w HPS Equivalent)	Exclusive	400	470	230	>180 - 280	240.0	0.240	4252	1,020.5	$ 0.05496	$56.09	$ 4.67	$ 24.71	$ 20.04
250 2/100' LED (400w 2/100' Equiv)	Exclusive	400	470	230	>180 - 280	240.0	0.240	4252	1,020.5	$ 0.05496	$56.09	$ 4.67	$ 38.20	$ 33.53
250 4/100' LED (400w 4/100' Equiv)	Exclusive	400	470	230	>180 - 280	240.0	0.240	4252	1,020.5	$ 0.05496	$56.09	$ 4.67	$ 28.06	$ 23.39

2.5% Sept 1, 2012 ARL Increase	2.50%
3.5% May 1, 2013 ARL Increase	3.50%
2.75% May 1, 2014 ARL Increase - Approved	2.75%
3.95% April 1, 2015 ARL Proposed	3.95%
Projected Cummulative Rate Increases	13.31%
2012/13 ARL Energy Cost (PCOSS13) at April 1, 2012 Rates	4.850
Projected PCOSS Energy Rate (cents/kWh)	5.496

Section:	Appendix 6.3	**Page No.:**	21 of 25
Topic:	Bill Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

Advise why, on a wattage basis, these rates are more expensive than equivalent high-pressure sodium rates.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Street light rates cannot be directly compared on a per watt basis as the rate includes other components other than just the cost of the energy usage of the light itself. Other costs such as the cost of the pole standard remain fixed regardless of the wattage of the light attached to it. Therefore, the lower the wattage, the higher the cost on a per watt basis.

Section:	Appendix 6.3	Page No.:	21 of 25
Topic:	Bill Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

For each of the categories of LED bulbs, please explain what type of high-pressure sodium or other existing bulb would be replaced.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH-I-49a.

Section:	Appendix 6.3	**Page No.:**	21 of 25
Topic:	Bill Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

Indicate the current status of installations in new areas and as a replacement for existing bulbs. To the extent the status differs from what is shown in Manitoba Hydro's Power Smart Plan, please explain the reasons for the difference.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Under the 2014 – 2017 Power Smart Plan, Manitoba Hydro plans to convert 130,000 roadway lights to LED over a seven year period under the LED Roadway Lighting Conversion Program. Vendor response to the material tender for the LED fixtures was very positive, resulting in a large number of detailed proposals requiring more time to fully review. This has resulted in the number of lights to be converted in the first year of the program (2014/15) being lower than projected. Notwithstanding the conversion in the first year being lower than projected, Manitoba Hydro expects to complete the conversions within the original seven year timeframe.

Installations of LED Roadway Lighting in new developments have begun with the new Devonshire and Crocus Meadows developments in North-West Winnipeg. These two developments are presently under construction and, when complete, will have over 170 LED streetlights.

Section:	6	**Page No.:**	6 of 21, Appendix 6.12
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Limited Use of Billing Demand		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is proposing to increase the basic charge for this rate class to the same level as for regular GS Small/Medium customers, set the demand charge at approximately 25% of the general demand charge, and base the energy charge on achieving revenue neutrality at a load factor of approximately 18%.

QUESTION:

Provide a table comparing the existing rate items (basic charge, demand charge, energy charge) for the LUBD rate against the ones applied for, indicating percentage changes.

RATIONALE FOR QUESTION:

Manitoba Hydro has applied for changes to the LUBD rate.

RESPONSE:

The table on the following page provides the current and proposed rates for the LUBD rate classes.

The rates proposed for LUBD customers are derived from the rates proposed for General Service Small, Medium and Large customer classes. The monthly Basic Charge is the same as proposed for the regular GS Small/Medium customer classes. The Demand Charge is set at approximately 25% of the proposed Demand Charge of the corresponding regular General Service class, with the Energy Charge calculated to provide revenue neutrality at a load factor of approximately 18%.

Manitoba Hydro notes that, in the table below, the percentage increase in the demand charge is reflective of the rounding that occurs in calculating the demand rate. For example, the LUBD Small and LUBD Medium Demand Charge is determined by taking 25% of the proposed GS Small and Medium Demand Charge and then rounding to two decimal places. The April 2015 demand charge is $2.3625 which rounds to $2.36. The April 2016 demand charge is calculated as $2.4558 which rounds to $2.46. At four decimal places, the percentage change is 3.95%, whereas the rounded amounts indicate a 4.24% increase.

		Current Rate	Proposed April 2015	% Change	Proposed April 2016	% Change
LUBD Small:	Basic Charge 1 Ph	$19.73	$20.51	3.95%	$21.32	3.95%
	Basic Charge 3 Ph	$27.82	$28.92	3.95%	$30.06	3.94%
	Energy Charge	$0.08795	$0.09146	3.99%	$0.09502	3.89%
	Demand Charge	$2.27	$2.36	3.96%	$2.46	4.24%
LUBD Medium:	Basic Charge	$29.36	$30.52	3.95%	$31.73	3.96%
	Energy Charge	$0.08795	$0.09146	3.99%	$0.09502	3.89%
	Demand Charge	$2.27	$2.36	3.96%	$2.46	4.24%
LUBD Large 750-30 kV:	Energy Charge	$0.07788	$0.08095	3.94%	$0.08417	3.98%
	Demand Charge	$1.93	$2.01	4.15%	$2.09	3.98%
LUBD Large 30-100 kV:	Energy Charge	$0.06915	$0.07190	3.98%	$0.07471	3.91%
	Demand Charge	$1.65	$1.72	4.24%	$1.79	4.07%
LUBD Large >100 kV:	Energy Charge	$0.06381	$0.06653	4.26%	$0.06914	3.92%
	Demand Charge	$1.50	$1.53	2.00%	$1.59	3.92%

Section:	6	**Page No.:**	6 of 21, Appendix 6.12
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Limited Use of Billing Demand		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is proposing to increase the basic charge for this rate class to the same level as for regular GS Small/Medium customers, set the demand charge at approximately 25% of the general demand charge, and base the energy charge on achieving revenue neutrality at a load factor of approximately 18%.

QUESTION:

For the customers shown in Table 5 of Appendix 6.12 that would qualify for the proposed Time-of-Use rates if implemented, please indicate the benefit, if any, those customers could realize if they switched to TOU.

RATIONALE FOR QUESTION:

Manitoba Hydro has applied for changes to the LUBD rate.

RESPONSE:

Of the customers shown in Table 5 of Appendix 6.12 that would qualify for the proposed Time-of-Use (TOU) rates, none would benefit if they switched to TOU.

For purposes of comparison between rate options, the actual energy and demand incurred by these customers in 2013/14 was used to calculate the annual costs under proposed LUBD and TOU rates for April 1, 2016. Based on their energy consumption from that year and applying the proposed April 1, 2016 rates, the revenues generated would be $145,391 on LUBD and $160,628 on TOU.

Section:	6	**Page No.:**	13 of 21
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Surplus Energy Program		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's changes to the Surplus Energy Program are not new – rather, they are the ones approved on an interim basis in Order 43/13

QUESTION:

Given that almost two years have passed since the change to Option 1 was approved on an interim basis, and to date no customers have made use of this option, please explain Manitoba Hydro's rationale for continuing to make this option available.

RATIONALE FOR QUESTION:

This Information Request explores the impact of the SEP program and options for customers.

RESPONSE:

Manitoba Hydro is seeking final approval for changes to Option 1 so that eligible customers can consider this Option as a viable alternative to firm rates for a portion of their electric load. The SEP product is an alternative rate option available to eligible customers seeking opportunities to obtain non-firm supply at variable rates equivalent to short-term market prices, or run-off prices in the event of export constraint. There are no additional costs to Manitoba Hydro for providing this rate option under SEP, and Manitoba Hydro is held whole through the design of the rate structure, so the SEP rate provided under Option 1 remains available should eligible customers choose to subscribe in the future.

Section:	6	**Page No.:**	13 of 21
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Surplus Energy Program		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's changes to the Surplus Energy Program are not new – rather, they are the ones approved on an interim basis in Order 43/13

QUESTION:

Please advise whether Manitoba Hydro anticipates any customers to shift to Option 1 if the Time-of-Use rate proposal is approved.

RATIONALE FOR QUESTION:

This Information Request explores the impact of the SEP program and options for customers.

RESPONSE:

The Time-of-Use rate proposal relates to Manitoba Hydro's delivery of a firm energy product, with predictable pricing and long-term availability. The Surplus Energy Program – Option 1 rate relates to the delivery of a non-firm, interruptible energy product with variable pricing based on opportunity pricing for surplus energy and uncertain availability into the future. As such, the two rates speak to different customer needs and priorities and are therefore not deemed to be in competition with each other.

Large customers invest considerable capital in processes and infrastructure that are highly dependent on a firm and reliable supply of energy for customers to achieve an expected return on their investment. This requirement generally places a high priority on predictable pricing and long-term availability of energy supply. The SEP – Option 1 rate is focused towards loads that customers would deem to be interruptible over the short or long-term, or loads for which customers have invested in alternate, or back-up, supply. It is not anticipated that customers will undertake significant investments specifically to capture the benefits of a non-firm energy product with variable pricing and potential for interruption given the competitive nature of the firm rates (including the proposed Time-of-Use rate) offered by Manitoba Hydro.

Section:	6	**Page No.:**	13 of 21
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Surplus Energy Program		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's changes to the Surplus Energy Program are not new – rather, they are the ones approved on an interim basis in Order 43/13

QUESTION:

Discuss the conditions under which a Time-of-Use customer would benefit from switching to Option 1.

RATIONALE FOR QUESTION:

This Information Request explores the impact of the SEP program and options for customers.

RESPONSE:

Time-of-Use customers may potentially benefit financially in instances where their loads are sufficiently predictable to provide the required Reference Levels of Demand (i.e. no less than 75 percent of the Total Load, unless the customer qualifies under available exemptions) required for participation under Option 1, and the variable Option 1 weekly rate is lower than the comparable firm energy-only rate available under the proposed Time-of-Use rate. It is important to recognize that the top quartile of a customer's total demand is also the most variable over time, so the SEP – Option 1 benefit may be highly variable as it will only be available during those intervals when a customer's load is greater than the Reference Levels of Demand specified prior to participation in Option 1.

The customer may however not deem the potential financial benefits worthy of the potential risk from unexpected price SEP increases during periods of volatile system consumption (on-peak winter and summer periods) or interruption (lack of surplus energy availability) if such load is required to operate in order to sustain the customer's operations and alternative supply is insufficient or costly.

Section:	6	Page No.:	14 of 21
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Curtailable Rates Program		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro seeks to finalize the interim approval of the changes to the Curtailable Rates Program (CRP) in Order 43/13, change defined peak- and off-peak periods to correspond to Time-of-Use timeframes, and eliminate Options "C" and "CE"

QUESTION:

Advise why, in Manitoba Hydro's view, there should be a limit on this program, and quantify how Manitoba Hydro arrives at this limit.

RATIONALE FOR QUESTION:

This question seeks an update to evidence provided by Manitoba Hydro in the previous GRA, based on which the PUB provided interim approval.

RESPONSE:

Please find attached Manitoba Hydro's responses to CAC/MH II-28(a), PUB/MHI I-141(d) and CAC/MH I-84(a) from the 2012/13 & 2013/14 GRA. The reasons provided at that time are still valid today.

CAC/MH I-84

Subject: **Proposed Rates and Customer Impacts**
Reference: **Tab 10, pages 6 – 7**
Tab 10, Appendix 10.4

a) Why is Manitoba Hydro proposing to eliminate Options "C" and "CE"?

ANSWER:

Several factors were considered in proposing to eliminate Options C and CE from the Curtailable Rate Program:

- Curtailable load achieves most of its benefits from responding to emergencies. By definition emergency situations are not forecast and if they occur rarely last longer than an hour. As Option C has a one hour notice requirement, it is rare that a situation would arise where an Option C curtailment would be useful.
- Manitoba Hydro has not initiated a curtailment under Option C since 2005. The payment of monthly credits under this option is not warranted when weighed against the limited benefits of having Option C load available.
- Option CE would no longer be available given the elimination of Option C.
- There is currently only one customer receiving service under Option C, and no customers receive service under Option CE. Manitoba Hydro intends to grandfather the existing Option C customer for a one year period subsequent to the confirmation of the rate approval process for the Curtailable Rate Program.

PUB/MH I-141

Reference: Curtailable Rates Program (CRP)/2011/12 PRP

d) Please explain how the DSM resource and the CRP resource needs are determined.

ANSWER:

The Curtailable Rates Program (CRP) has been developed over many years in conjunction with Manitoba Hydro's large industrial customers. The size of the CRP initially reflected the capability of our customers to supply capacity under terms and conditions that make the resource useful at a price equivalent to Manitoba Hydro's resource alternative. The DSM resource for the CRP is determined by aggregating the load available to be curtailed by participating customers.

In February 2005, Manitoba Hydro capped the CRP resource at 230 MW for Options A and C combined and 100 MW for Option R. At that time, Manitoba Hydro advised that the purpose for the upper limit on load subscription to the CRP was to ensure that Curtailable Load would have value for Manitoba Hydro commensurate with the Reference Discount being offered at that time.

The current GRA includes provisions to eliminate Option C and to further reduce the upper subscription limit on Option A from 230 MW to either 180 MW (if the current Option C customers opts to move their curtailable load to Option A) or 150 MW (if the current Option C customer elects to exit the program entirely). It is also proposed to reduce the maximum subscription under Option R from 100 MW to 50 MW.

Please see Manitoba Hydro's responses to PUB/MH I-141(a) and CAC/MH I-84(c) for further discussion of these proposed revisions to the CRP.

CAC/MH II-28

Subject: Proposed Rates and Customer Charges
Reference: CAC/MH I-84 e)

a) **The response provided does not address the original question which was - what are the limits, if any, on the amount of curtailable load that Manitoba Hydro can effectively use. Please respond to the question as posed. If the response depends on the Option, please address by Option.**

ANSWER:

Limits for effective use of Curtailable Load:

Option 'R' – 90 MW. This is equivalent to MH's supplemental contingency reserve obligation to the MISO-MH Contingency Reserve Sharing Group. However, MH currently allocates only 50 MW of Option 'R' load. There is decreasing value from contracting more Option 'R' load (if it were available) for supplemental reserve as MH normally has some contingency reserve available on its hydraulic generation.

Option 'A' – There is no technical limit assuming the entire load could be curtailed in a timely and efficient manner. However, because Option 'A' load can be used to re-establish contingency reserves, a breakpoint in the effective use of this load is equivalent to MH's supplemental contingency reserve obligation of 90 MW. Beyond 90 MW, Option 'A' load has a lesser value to MH in restoring contingency reserves; more than 90 MW would be required in the less likely event that MH were to experience multiple contingencies or a series of contingencies in close succession. In this instance, successive activation (and restoration) of contingency reserves may be required, hence the limit of 180 MW which is double MH's supplemental contingency reserve requirement.

Option 'C' – There is no technical limit. However as explained in PUB/MH II-99(b), notification requirements limit the effectiveness of this type of curtailable load.

Option 'E' – There is no technical limit. However, similar to Option 'C' load, notification requirements limit the effectiveness of this type of curtailable load.

The limits imposed on curtailable load in the Proposed Terms and Conditions filed in Appendix 10.4 of the Application represent effective limits on the various types of curtailable load, considering both reliability and economic benefits of this resource.

Section:	6	Page No.:	14 of 21
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Curtailable Rates Program		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro seeks to finalize the interim approval of the changes to the Curtailable Rates Program (CRP) in Order 43/13, change defined peak- and off-peak periods to correspond to Time-of-Use timeframes, and eliminate Options "C" and "CE"

QUESTION:

In response to PUB/MH I-141 from the 2012/13 and 2013/14 GRA, Manitoba Hydro indicated that it anticipated a capacity market forming within MISO. Please provide Manitoba Hydro's current view of this issue.

RATIONALE FOR QUESTION:

This question seeks an update to evidence provided by Manitoba Hydro in the previous GRA, based on which the PUB provided interim approval.

RESPONSE:

MISO established a capacity market effective June 1, 2013. It conducts an annual voluntary capacity auction referred to as the Planning Resource Auction (PRA) for each of the 9 load zones within the MISO footprint, every March for the immediately following Planning Year (June 1 – May 31). The offer price of the marginal unit sets the clearing price that is paid to all cleared capacity resources within a zone. Capacity offered into the PRA must be available for the entire Planning Year. Manitoba Hydro has participated in the 13/14 and 14/15 PRAs in Local Resources Zone #1 and is considering participating in the upcoming PRA for the 15/16 Planning Year.

Section:	6	**Page No.:**	14 of 21
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Bill Impacts		
Issue:	Curtailable Rates Program		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro seeks to finalize the interim approval of the changes to the Curtailable Rates Program (CRP) in Order 43/13, change defined peak- and off-peak periods to correspond to Time-of-Use timeframes, and eliminate Options "C" and "CE"

QUESTION:

Advise whether any customers have sought to increase the CRP in excess of the cap. If so, please quantify and advise of Manitoba Hydro's response to these customers.

RATIONALE FOR QUESTION:

This question seeks an update to evidence provided by Manitoba Hydro in the previous GRA, based on which the PUB provided interim approval.

RESPONSE:

Several customers have inquired whether opportunities exist to participate in the Curtailable Rate Program in excess of the caps, but no specific quantities have been referenced in those inquires. Manitoba Hydro's response has remained consistent with response provided in previous GRA filings. Please see Manitoba Hydro's response to PUB/MH-I-52a, which attaches responses from the 2012/13 & 2013/14 GRA discussing Manitoba Hydro's reasons for limits on the CRP.

Section:	Appendix 6.3	**Page No.:**	21 of 25
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

Explain how Manitoba Hydro arrived at these proposed rates and provide the detailed calculations.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Please see the response to PUB/MH-I-49a.

Section:	Appendix 6.3	**Page No.:**	21 of 25
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

Advise why, on a wattage basis, these rates are more expensive than equivalent high-pressure sodium rates.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Please see the response to PUB/MH-I-49b.

Section:	Appendix 6.3	**Page No.:**	21 of 25
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

For each of the categories of LED bulbs, please explain what type of high-pressure sodium or other existing bulb would be replaced.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Please see the response to PUB/MH-I-49c.

Section:	Appendix 6.3	**Page No.:**	21 of 25
Topic:	Proposed Rates and Customer Impacts		
Subtopic:	Area and Roadway Lighting Rates		
Issue:	LED Rates		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is seeking nine different LED-based area and roadway lighting rates.

QUESTION:

Indicate the current status of installations in new areas and as a replacement for existing bulbs. To the extent the status differs from what is shown in Manitoba Hydro's Power Smart Plan, please explain the reasons for the difference.

RATIONALE FOR QUESTION:

Manitoba Hydro seeks to finalize interim LED rates.

RESPONSE:

Please see the response to PUB/MH-I-49d.

Section:	Tab 7, App. 7.1	Page No.:	Table 5, p.7
Topic:	Electric Load Forecast		
Subtopic:	General Consumers Sales		
Issue:	10 Year Load Growth		

PREAMBLE TO IR (IF ANY):

Table 5 indicates that MH anticipates 10 year average annual growth rates for:

Residential	1.4%	(1.6% in previous decade)
Mass Market	1.7%	(1.4% in previous decade)
To Consumers	2.8%	(0.1% in previous decade)
Total Sales	1.9%	(1.1% in previous decade)

QUESTION:

Confirm that MH's Top Consumers are expected to provide 39% of the total load growth in the next 10 years; with Mass Market providing 36% and Residential 15%.

RATIONALE FOR QUESTION:

To review the sources of Manitoba Hydro's load growth.

RESPONSE:

Manitoba Hydro confirms that Mass Market represents 36% (1,612 GW.h) and Top Consumers represent 39% (1,716 GW.h) of total sales growth over the next 10 years. Manitoba Hydro notes that Residential Basic is expected to represent 25% (1,093 GW.h) of the remaining total sales growth over the next 10 years, totaling 4,440 GW.h.

Section:	Tab 7, App. 7.1	Page No.:	Table 5, p.7
Topic:	Electric Load Forecast		
Subtopic:	General Consumers Sales		
Issue:	10 Year Load Growth		

PREAMBLE TO IR (IF ANY):

Table 5 indicates that MH anticipates 10 year average annual growth rates for:

Residential	1.4%	(1.6% in previous decade)
Mass Market	1.7%	(1.4% in previous decade)
To Consumers	2.8%	(0.1% in previous decade)
Total Sales	1.9%	(1.1% in previous decade)

QUESTION:

Provide industry sector load growth (MW & GWh) tabulation from 2007/08 to 2013/14 (actual) and from 2013/14 to 2023/24 (forecast) including the extent of potential large industrial load.

RATIONALE FOR QUESTION:

To review the sources of Manitoba Hydro's load growth.

RESPONSE:

Residential and General Service Mass Market are not forecast by industry sector. At the most detailed level, the forecast is available by rate groups. MW is only forecast at generation and is not available for General Consumers Sales.

Top Consumers are forecast by individual customers and have been classified by sector. The following table presents the past growth for the period of 2007/08 to 2013/14 and the forecast growth for the period of 2014/15 to 2023/24. This corresponds to the Top Consumers column in Table 5 on Page 7 of Appendix 7.1.

Top Consumers by Industry Sector (GW.h)

Fiscal Year	Primary Metals & Mining	Chemical / Treatment	Petro / Oil / Natural Gas	Pulp / Paper	Food / Beverage	College	PLIL	Total
2007/08	2,304	1,865	879	764	188	75	0	6,075
2008/09	2,241	1,929	944	674	202	75	0	6,065
2009/10	2,036	1,912	903	332	204	74	0	5,461
2010/11	2,157	1,977	728	185	201	76	0	5,324
2011/12	2,203	2,018	856	171	203	80	0	5,531
2012/13	2,183	1,993	880	222	198	84	0	5,560
2013/14	2,165	1,993	810	201	206	86	0	5,461
Ave gr.	-1.0%	1.1%	-1.3%	-20.0%	1.6%	2.3%		-1.8%
2014/15	2,270	2,095	1,070	260	215	93	0	6,003
2015/16	2,095	2,165	1,310	265	215	97	0	6,147
2016/17	1,855	2,165	1,485	265	215	97	0	6,082
2017/18	1,855	2,165	1,730	265	215	97	103	6,430
2018/19	1,855	2,165	1,800	265	215	97	193	6,590
2019/20	1,835	2,165	2,005	265	215	97	277	6,859
2020/21	1,815	2,165	2,005	265	215	97	360	6,922
2021/22	1,815	2,165	2,005	265	215	97	444	7,006
2022/23	1,815	2,165	2,005	265	215	97	529	7,091
2023/24	1,815	2,165	2,005	265	215	97	615	7,177
Ave gr.	-1.7%	0.8%	9.5%	2.8%	0.4%	1.2%		2.8%

Section:	Tab 7, App. 7.1	**Page No.:**	Table 5, p.7
Topic:	Electric Load Forecast		
Subtopic:	General Consumers Sales		
Issue:	10 Year Load Growth		

PREAMBLE TO IR (IF ANY):

Table 5 indicates that MH anticipates 10 year average annual growth rates for:

Residential	1.4%	(1.6% in previous decade)
Mass Market	1.7%	(1.4% in previous decade)
To Consumers	2.8%	(0.1% in previous decade)
Total Sales	1.9%	(1.1% in previous decade)

QUESTION:

Explain why MH's load forecast for 2014/15 indicates a one year increase of:

- 0.9% for residential
- 2.1% for Mass Market
- 9.8% for Top Consumers
- 4.2% Total

RATIONALE FOR QUESTION:

To review the sources of Manitoba Hydro’s load growth.

RESPONSE:

The one year increases from the 2013/14 Weather Adjusted History to the first year of the forecast (2014/15) are as follows:

Residential Basic :	1.8%	(7,249 GW.h to 7,380 GW.h)
Mass Market :	2.6%	(8,587 GW.h to 8,814 GW.h)
Top Consumers :	9.9%	(5,461 GW.h to 6,003 GW.h)
Total Sales :	4.2%	(21,566 GW.h to 22,467 GW.h)

The one year increases for the Residential Basic and Mass Market sectors are primarily driven by the population, real income and real GDP which are projected to grow by 1.2%, 1.5%, and 2.2% respectively for the first year of the forecast (2014/15).

Top Consumers are forecast individually for the first 3 to 5 years of the forecast. Based upon these individual short term forecasts, the increase for the Top Consumer sector in the first year of the forecast (2014/15), as detailed in Manitoba Hydro's response to PUB/MH I-54(b), is primarily driven by projected growth in the Petrol (pipelines), Primary Metals and Chemical sectors.

Section:	9	Page No.:	Figure 9.3, Page 7
Topic:	Energy Supply		
Subtopic:	DSM Impacts		
Issue:	Changes to DSM Load Reduction		

PREAMBLE TO IR (IF ANY):

In the NFAT 2013 update, MH provided annual DSM Level 2 load reductions in average years. In the 2014 PRP MH provided comparable data as follows:

	2013 NFAT Update Level 2 DSM (GWh)	2014 PRP DSM (GWh)
2014/15	382	305
2015/16	637	415
2016/17	1196	780
2017/18	1475	1056
2018/19	1890	1407
2019/20	2068	1730
2020/21	2217	1988
2021/22	2325	2183
2022/23	2459	2296
2023/24	2552	2405

QUESTION:

Confirm the above tabulation of DSM energy savings is accurately represented.Please explain the reduced level of DSM in 2014.

RATIONALE FOR QUESTION:

To determine the level of DSM load reductions forecast by Manitoba Hydro.

RESPONSE:

In the 2014 power resource plan, the DSM forecast has a starting year of 2014/15. The 2013 NFAT Update Level 2 DSM forecast has a starting year of 2013/14. To appropriately compare the two DSM forecasts the timeframe for both forecasts must be consistent, therefore the energy savings from 2013/14 in the 2013 NFAT Update Level 2 DSM forecast that persist through the forecast must be removed from each year. The table below shows the 2013 NFAT Update Level 2 DSM forecast energy savings after removing the 2013/14 savings of 138 GW.h from each year.

The energy savings in the 2014/15 and 2015/16 rows of the 2014 power resource plan are incorrect. The correct values have been updated in Figure 9.3 of Tab 9 and they are reproduced in the table below.

	2013 NFAT Update Level 2 DSM (GW.h)	**2014 PRP DSM (GW.h)**	**2014 PRP DSM Increase or (Decrease)**
2014/15	244	283	39
2015/16	499	487	(12)
2016/17	1,058	780	(278)
2017/18	1,337	1,056	(281)
2018/19	1,702	1,407	(296)
2019/20	1,925	1,730	(194)
2020/21	2,079	1,988	(91)
2021/22	2,187	2,183	(4)
2022/23	2,321	2,296	(25)
2023/24	2,414	2,405	(9)

The 2013 NFAT Update Level 2 DSM savings were based upon a high-level assessment of forecast energy savings created as part of a sensitivity run for the NFAT hearing. The DSM energy savings included in the 2014 power resource plan were based upon more detailed and refined program designs undertaken subsequent to the Level 2 DSM saving estimates. As such, the energy savings provided in the 2014 power resource plan are an updated estimate to the 2013 NFAT Update Level 2 DSM savings.

The table below outlines the impacts from four modifications to the 2014 – 2017 Power Smart Plan which contributed to the majority of the variances between the two DSM forecasts. The four modifications were related to code savings, delays in expected implementation of fuel choice and conservation rate initiatives and modifications to the energy savings expected from the Load Displacement Program.

	Removal of Manitoba Energy Code for Buildings	**Later Launch of Fuel Choice**	**Later Launch of Conservation Rates**	**Modifications to Load Displacement Program**	**Total Change from 2013 NFAT Update Level 2 DSM**
2014/15	(11)	(57)	0	113	45
2015/16	(21)	(114)	0	139	3
2016/17	(32)	(171)	0	(48)	(252)
2017/18	(42)	(172)	(29)	(4)	(248)
2018/19	(53)	(171)	(123)	59	(288)
2019/20	(53)	(114)	(68)	48	(188)
2020/21	(53)	(57)	(49)	70	(90)
2021/22	(53)	0	(24)	70	(7)
2022/23	(83)	0	(25)	70	(39)
2023/24	(113)	0	(14)	70	(58)

There was also a change in the assignment of code savings in the 2014 power resource plan. The 2013 NFAT Update Level 2 DSM savings included energy savings based on the estimated projected impact of the adoption of the Manitoba Energy Code for Buildings (MECB) which were to become effective December 1, 2014. Energy savings of 113 GW.h in 2023/24 were included as part of the DSM program forecast since they had not been included as a "Codes & Standards" reduction in the 2013 Load Forecast at that time. With the MECB coming into effect in December 2014, the forecast energy reductions due to this code were shifted to "Codes & Standards" for the 2014 – 2017 Power Smart Plan and reflected as a reduction in the 2014 Load Forecast. Based on updated estimates of the impacts from this code, the 2014 Load Forecast was reduced by approximately 230 GW.h in 2023/24 (i.e. a higher impact than previously estimated).

Forecast savings for the Fuel Choice Initiative were included in the 2013 NFAT Update beginning in 2014/15. When this initiative was further refined during the 2014 - 2017 Power

Smart Plan process, a launch date of 2017/18 was incorporated resulting in the forecast savings occurring later in the planning period.

Forecast savings for the Conservation Rates Initiative was included in the 2013 NFAT Update with Residential Conservation Rate energy savings beginning in 2017/18 and Commercial Conservation Rate energy savings beginning in 2018/19. When this initiative was further refined during the 2014 - 2017 Power Smart Plan process, a launch date of 2018/19 for Residential Conservation Rates and 2019/20 for Commercial Conservation Rate were incorporated resulting in the forecast savings occurring later in the planning period.

Forecast energy savings for the Load Displacement Program that were included in the 2013 NFAT were refined during the 2014 – 2017 Power Smart Plan process. This resulted in a change in the timing and magnitude of the forecast energy savings from this program.

Section:	Tab 9	Page No.:	p. 7 of 23 Tab 9
Topic:	Energy Supply		
Subtopic:	Export Resources		
Issue:	Hydraulic Generation Available for Export		

PREAMBLE TO IR (IF ANY):

MH's 2014 PRP anticipates the following:

	Total Exports (GWh)	Surplus Hydraulic Generation (GWh)	
2014/15	11299	10110	
2015/16	10426	9151	
2016/17	8034	6428	
2017/18	7728	5011	-2489
2018/19	7698	3652	
2019/20	7876	3939	

QUESTION:

Confirm that MH export sales going out to 2019/20 are declining and require increasing levels of non-hydraulic resources.

RATIONALE FOR QUESTION:

Extraprovincial revenues are deducted from revenue requirements.

RESPONSE:

The values in the following table are based on Figure 9.3 in Tab 9 of the Application, and are in units of GWh at generation. Manitoba Hydro cannot confirm the numbers referenced in the preamble for Surplus Hydraulic Generation (GWh). This table confirms that from

2014/15 to 2019/20 total export sales and total non-hydraulic resources show increases and decreases.

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Export Sales	11299	10426	8034	7728	7698	7876
Total Non-Hydraulic	1199	1347	2717	2828	3158	3047

In years 2014/15 and 2015/16 the Total Export Sales value is relatively higher and the Total Non-Hydraulic supply value is relatively lower than in subsequent years due to favourable water conditions in the near term. Favourable water conditions increase the amount of hydraulic generation available for export and reduce the need for and economic attractiveness of imports. For load years 2016/17 and beyond, the energy values represent the average energy quantities based on 102 historic flow cases which include droughts resulting higher requirements for non-hydraulic resources.

For a fixed set of resources and water conditions, increases in the Manitoba load result in a decrease in contracted export volumes. Net Manitoba load is projected to steadily increase out in time, driving the decreasing contracted exports trend from 2016/17 to 2019/20.

Please see Manitoba Hydro's response to PUB/MH-I-15b for the projected total export volumes through 2019/20 and an explanation of changes to the total export volumes.

Section:	Tab 9	**Page No.:**	p. 7 of 23 Tab 9
Topic:	Energy Supply		
Subtopic:	Export Resources		
Issue:	Hydraulic Generation Available for Export		

PREAMBLE TO IR (IF ANY):

MH's 2014 PRP anticipates the following:

	Total Exports (GWh)	**Surplus Hydraulic Generation (GWh)**	
2014/15	11299	10110	
2015/16	10426	9151	
2016/17	8034	6428	
2017/18	7728	5011	-2489
2018/19	7698	3652	
2019/20	7876	3939	

QUESTION:

Confirm that the ‘profitability’ of MH's exports (in terms of contribution to fixed costs or retained earnings) is largely related to the hydraulic generation resource which essentially yield a ‘profit’ of the export price minus water rentals and minus transmission costs.

RATIONALE FOR QUESTION:

Extraprovincial revenues are deducted from revenue requirements.

RESPONSE:

As a predominantly hydro system, by design there will be energy surplus to the needs of Manitobans that will provide benefit to Manitobans when sold into the export market. Manitoba Hydro operates an integrated system in which all available resources (hydraulic and non-hydraulic) are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations.

A calculation of net export revenue would be based on export revenues net of water rentals and fuel and power purchased as explained in IFF14 Appendix 3.3 of this Application.

Provided the transaction is necessary to serve the Manitoba load or provides a positive contribution to net extra-provincial revenue over the long run, Manitoba Hydro would enter into the transaction to provide the contribution to net extra-provincial revenue and reduce revenue requirements for Manitoba ratepayers.

Section:	Tab 9	**Page No.:**	p. 7 of 23 Tab 9
Topic:	Energy Supply		
Subtopic:	Export Resources		
Issue:	Hydraulic Generation Available for Export		

PREAMBLE TO IR (IF ANY):

MH's 2014 PRP anticipates the following:

	Total Exports (GWh)	**Surplus Hydraulic Generation (GWh)**	
2014/15	11299	10110	
2015/16	10426	9151	
2016/17	8034	6428	
2017/18	7728	5011	-2489
2018/19	7698	3652	
2019/20	7876	3939	

QUESTION:

Confirm that MH's thermal generation and wind purchases are typically not competitive in the export market.

RATIONALE FOR QUESTION:

Extraprovincial revenues are deducted from revenue requirements.

RESPONSE:

This statement can only be partially confirmed.

Under normal water conditions, Manitoba Hydro's thermal generating resources are typically economic resources only under peak Manitoba / MISO market load conditions. Generation from Manitoba Hydro's simple cycle combustion turbines is typically not competitive relative to export market prices due to their very poor efficiencies.

The Climate Change and Emissions Reductions Act limits operation of coal fired generation in Manitoba to be for emergency purposes only, therefore Manitoba Hydro's coal fired generation is not dispatched for export purposes regardless of its market competitiveness.

Manitoba Hydro's wind PPAs are designed such that, if Manitoba Hydro were to choose to curtail wind energy, Manitoba Hydro would still be obligated to pay for the energy that would have otherwise been generated. Therefore, only in the rare circumstance where the market price of electricity went negative would it make economic sense for Manitoba Hydro to curtail the delivery of wind energy under its PPAs.

Wind generation provides a dependable energy resource to Manitoba Hydro's supply portfolio.

Section:	Tab 9	Page No.:	p. 7 of 23 Tab 9
Topic:	Energy Supply		
Subtopic:	Export Resources		
Issue:	Hydraulic Generation Available for Export		

PREAMBLE TO IR (IF ANY):

MH's 2014 PRP anticipates the following:

	Total Exports (GWh)	Surplus Hydraulic Generation (GWh)	
2014/15	11299	10110	
2015/16	10426	9151	
2016/17	8034	6428	
2017/18	7728	5011	-2489
2018/19	7698	3652	
2019/20	7876	3939	

QUESTION:

Provide an Export Price vs Cost Comparison for MH's DSM resources and imports.

RATIONALE FOR QUESTION:

Extraprovincial revenues are deducted from revenue requirements.

RESPONSE:

As indicated in Order 33/15, this question seeks aggregate information on average annual export prices, imports and DSM revenues. DSM benefits include reduced operating costs and deferral of investment in new resources over the long-term; they are not directly comparable to the export revenues in any given year. A general comparison of the incremental export market value provided by Manitoba Hydro's DSM portfolio over the long-term relative to the cost of DSM programs can made using Manitoba Hydro’s long-run marginal value and the levelized resource cost of Manitoba Hydro’s DSM portfolio. Manitoba Hydro’s response to COALITION/MH-I-67a) provides Manitoba Hydro’s current long-run average all-in marginal value which is 7.52¢/kW.h. This value, when compared to the levelized resource cost of Manitoba Hydro’s DSM portfolio of 3.9¢/kW.h, as provided in Appendix 8.1 on page 38, indicates a positive benefit.

Appendix 11.19 of this application contains Average Unit Revenue/Cost data for Total Export Sales and Purchased Energy. It should be noted that the Purchased Energy category includes an optimized quantity of imports based on Manitoba Hydro system requirements, export price and expected availability from the market over the long term.

Section:	Tab 9	Page No.:	P.7 of 23
Topic:	Energy Supply		
Subtopic:	Domestic Load Forecasts		
Issue:	10 Year Load Growth		

PREAMBLE TO IR (IF ANY):

MH's base domestic load forecast for 2023/24 appears to have been reduced by 865 GWh from the 30,491 GWh in the NFAT 2013 update which reflected new pipeline loads.

QUESTION:

Confirm the energy (GWh) and capacity (MW) tabulations of base load forecasts in 2011, 2012, NFAT 2013 update and 2014 in the attached table.

	Energy (GWh)					**Winter Capacity (MW)**			
	2011 Base Forecast (no pipeline)	**2012 Base Forecast** (no pipeline)	**NFAT 2013 Update** (with pipeline)	**2012 /2013** Δ pipeline	**2014 Base Forecast**	**2012 Forecast** (no pipeline)	**NFAT 2013 Update** (with pipeline)	**2012 /2013** Δ pipeline	**2014 Forecast**
2013/14	25930	25734	25239	24677	-138	4609	4601	-8	4587
2014/15	26684	26071	25676	25321	-382	4677	4680	+3	4716
2015/16	26404	26393	26013	25754	-637	4738	4742	+4	4803
2016/17	26794	26677	26692	26436	-1196	4794	4852	+58	4861
2017/18	27205	27128	27345	27174	-1475	4874	4958	+84	4985
2018/19	27481	27616	28112	27662	-1890	4959	5082	+123	5068
2019/20	27966	27919	28876	28247	-2068	5024	5204	+180	5166
2020/21	28462	28400	29267	28583	-2217	5109	5276	+167	5223
2021/22	28887	28859	29675	28937	-2325	5192	5349	+157	5284
2022/23	29311	29322	30083	29284	-2459	5276	5424	+148	5342
2023/24	29733	29779	30491	29626	-2552	5360	5498	+138	5400
10 yr inc	**+3803**	**+4045**	**+5252**	**+4949**		**751**	**897**		**+818**

RATIONALE FOR QUESTION:

Domestic load is used to forecast domestic revenues.

RESPONSE:

The following tables show the 2012, 2013 and 2014 forecasts, along with the NFAT 2013 update with the pipeline scenario for energy and peak capacity and the table also presents the difference between the NFAT 2013 update with the pipeline scenario and the 2014 base forecast.

	Energy (GWh)				
	2012 Base Forecast	**2013 Base Forecast**	**NFAT 2013 Update** (with pipeline)	**2014 Base Forecast**	**NFAT 2013- 2014 Difference**
2013/14	25734	25239	25239	24677	-562
2014/15	26071	25676	25676	25639	-37
2015/16	26393	26013	26013	26130	117
2016/17	26677	26322	26691	26436	-255
2017/18	27128	26606	27345	27174	-171
2018/19	27616	27003	28111	27662	-449
2019/20	27919	27398	28876	28247	-629
2020/21	28400	27789	29268	28583	-685
2021/22	28859	28197	29675	28937	-738
2022/23	29322	28605	30084	29284	-800
2023/24	29779	29013	30491	29626	-865
10 yr inc	**4045**	**3774**	**5252**	**4949**	

(shaded) denotes weather adjusted actual

	Winter Capacity (MW)				
	2012 Base Forecast	**2013 Base Forecast**	**NFAT 2013 Update** (with pipeline)	**2014 Base Forecast**	**NFAT 2013 - 2014 Difference**
2013/14	4609	4601	4601	4587	-14
2014/15	4677	4680	4680	4716	36
2015/16	4738	4742	4742	4803	61
2016/17	4794	4801	4851	4861	10
2017/18	4874	4857	4959	4985	26
2018/19	4959	4930	5082	5068	-14
2019/20	5024	5002	5205	5166	-39
2020/21	5109	5074	5276	5223	-53
2021/22	5192	5147	5350	5284	-66
2022/23	5276	5222	5424	5342	-82
2023/24	5360	5296	5498	5400	-98
10 yr inc	**751**	**695**	**897**	**813**	

Section:	Tab 9	Page No.:	P.7 of 23
Topic:	Energy Supply		
Subtopic:	Domestic Load Forecasts		
Issue:	10 Year Load Growth		

PREAMBLE TO IR (IF ANY):

MH's base domestic load forecast for 2023/24 appears to have been reduced by 865 GWh from the 30,491 GWh in the NFAT 2013 update which reflected new pipeline loads.

QUESTION:

Explain the 865 GWh/94 MW decline in 2014, from 2013, with specific reference to industry sectors affected.

RATIONALE FOR QUESTION:

Domestic load is used to forecast domestic revenues.

RESPONSE:

The 2014 base load forecast for 2023/24 was increased by 613 GW.h and 104 MW compared to the 2013 base load forecast. The 613 GW.h increase included an increase of 655 GW.h in pipeline load for two new pipeline projects that were not included in the 2013 forecast, and a net reduction of 42 GW.h to all other load.

The NFAT 2013 update filed as part of the NFAT proceedings (Manitoba Hydro Exhibit 104-3) was a scenario update to the 2013 Forecast designed to approximately represent the emerging information related to new planned pipeline expansions in the Petroleum sector. The scenario was 1,478 GW.h higher than the 2013 base load forecast for 2023/24.

The 865 GW.h difference between the NFAT 2013 update and the 2014 Forecast is from:

1. 1,478 GW.h extra load assumed in NFAT 2013 update, less
2. 655 GW.h load added for new pipeline projects in the 2014 Forecast, plus
3. 42 GW.h of other changes to the 2014 Forecast.

The pipeline load increase for 2023/24 in the 2014 forecast was 824 GW.h lower (1,478 GW.h – 655 GW.h) than the NFAT 2013 forecast. This lower forecast was for the pipeline load reflecting updated information on the expected load increases anticipated in this sector.

Section:	Tab 9	Page No.:	Sect. 9.1/Sect. 9.2Sect. pp. 1 to 7
Topic:	Energy Supply		
Subtopic:	Power Resource Plan		
Issue:	Relative DSM Achievement		

PREAMBLE TO IR (IF ANY):

At the NFAT hearings, MH put forward DSM Level 2 as a means of deferring new generation (Natural gas CCGT or Conawapa)

QUESTION:

File MH's 2014 PRP including appendices.

RATIONALE FOR QUESTION:

NFAT concluded that an advanced Keeyask Generating Station was preferable to other resources, based on a DSM Level 2 scenario.

RESPONSE:

The 2014/15 Power Resource Plan is included as an attachment to this response.

MANITOBA HYDRO 2014/15 POWER RESOURCE PLAN
September 18, 2014

EXECUTIVE SUMMARY

The purpose of the 2014/15 Power Resource Plan is to document the key assumptions for the 2014 recommended development plan for use in resource planning evaluations and to support the 2014 Integrated Financial Forecast. Based on the PUB's NFAT report, the Province of Manitoba approved the construction of Keeyask G.S. and a new 500 kV Manitoba/US Transmission Interconnection. While the NFAT process did not result in approval of the Conawapa G.S., it 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. It is expected that Manitoba Hydro will only reinitiate Conawapa project activities if future studies and review provide a strong business case. The 2014/15 Power Resource Plan does not trigger any additional work to protect an in-service date for Conawapa G.S.

The recommended development plan is as follows:

Committed Resources:
- Keeyask G.S. (695 MW) with a 2019/20 ISD,

Resources in Regulatory Approval Process:
- A new 500 kV US interconnection with a June 2020 ISD.

Proposed Resources:
- Conawapa G.S. (1485 MW) with a 2029/30 ISD,
- A transmission allowance for north–south transmission improvements beyond Bipole III, as required for the combined output of the Keeyask and Conawapa generating stations.

Related Sales
- The MH–MP 250 MW Sale Agreements dated May 2011,
- The WPS 100 MW Sale Agreement dated May 2011,
- The WPS 308 MW Sale Agreement dated Feb 26, 2014,
- The WPS 108 MW Sale Agreement dated Feb 26, 2014,
- The MH 200 MW Energy Purchase Agreement from WPS dated Feb 26, 2014,
- The NSP 125 MW Sale Agreement dated May 2010.

With the inclusion of Keeyask G.S. and the new 500 kV US interconnection as committed resources and the higher level of DSM reflected in the 2014 Power Smart Plan, new generation is not required to meet Manitoba load requirements until 2037/38.

This Power Resource Plan also includes the following projects:
- Pointe du Bois powerhouse rebuild by 2039/40,
- Bipole III completed by 2018/19.

TABLE OF CONTENTS

1 INTRODUCTION

The 2014/15 Power Resource Plan is the annual update to the long-term resource development plan to ensure that adequate resources are available to meet the electricity needs of the province of Manitoba. As the Needs For and Alternatives To (NFAT) process provided a comprehensive review resulting in approval of new major infrastructure included in the recommended development plan, the scope this year has been reduced and only provides an update in order to support the annual corporate resource and financial planning cycles. The Power Resource Plan supports the annual Integrated Financial Forecast (IFF) process as well as other long-term planning and corporate initiatives.

1.1 Resource Planning Criteria

Power resource planning is an essential activity in fulfillment of Manitoba Hydro's mission as stated in the Corporate Strategic Plan:

> "To provide for the continuance of a supply of energy to meet the needs of the province and to promote economy and efficiency in the development, generation, transmission, distribution, supply, and end-use of energy."

Resource planning is governed by Manitoba Hydro Policy P195, Generation Planning which includes the following Capacity and Energy Resource Planning criteria:

1. **Capacity Criterion**
   Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time.

2. **Energy Resource Planning**
   The Corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated. Imports may be considered as dependable energy resources provided they utilize Firm Transmission Service and are sourced from either an Organized Power Market or a bilateral contract. The total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the Off Peak Period, and shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load.

These planning criteria provide the basis for determining when new resources are required to ensure an adequate supply of capacity and energy for Manitoba.

2 NEED FOR NEW RESOURCES TO MEET EXISTING OBLIGATIONS

The need for new resources to meet the expected load requirements is assessed using supply assumptions which include the base supply of power resources including committed resources, and the Manitoba base load forecast net of DSM and export sales requirements. Using the planning criteria, the supply demand surplus or deficit is determined for each year for 35 years into the future. The year in which persistent deficits begin for either dependable energy or peak capacity is the year that new resources are required.

Table 1 shows the changes in the dates that new resources were needed for both energy and capacity compared to the 2013 NFAT development plan with level 2 DSM, additional pipeline load and Keeyask G.S. and the new 500kV US interconnection. The variation in the date new resources are needed is due to changes in the load forecast, demand side management (DSM), and base resource assumptions such as the timing of the Pointe du Bois powerhouse rebuild, allowable import quantities, and contract obligations.

For the 2014/15 Power Resource Plan, new resources are required for capacity in 2037/38.

Table 1: Changes to Supply-Demand Balances

Changes to Dependable Energy (GW.h)					
Fiscal Year	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**
System Surplus (Deficit) 2013, Keeyask, Level 2 DSM, pipeline load	**53**	**(265)**	**(592)**	**(927)**	**(1271)**
Decrease in MB Load	1436	1456	1478	1500	1521
Decrease in DSM	(562)	(589)	(616)	(624)	(650)
Pointe du Bois Rebuild - Revised	(150)	(150)	(150)	(3)	87
Decrease in Imports due to decrease in MB Load	(112)	(85)	(83)	(87)	(86)
Other	(106)	(136)	(148)	(128)	(128)
System Surplus (Deficit) 2014, No New Resources	**559**	**232**	**(111)**	**(269)**	**(528)**

Changes to Winter Peak Capacity (MWs)					
Fiscal Year	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**
System Surplus (Deficit) 2013, Keeyask, Level 2 DSM, pipeline load	**9**	**(55)**	**(119)**	**(186)**	**(253)**
Decrease in MB Load	268	277	286	296	304
Decrease in DSM	(190)	(203)	(215)	(226)	(238)
Pointe du Bois Rebuild - Revised	(45)	(45)	(45)	42	42
Other	(4)	(4)	(4)	(5)	(5)
System Surplus (Deficit) 2014, No New Resources	**38**	**(30)**	**(98)**	**(79)**	**(149)**

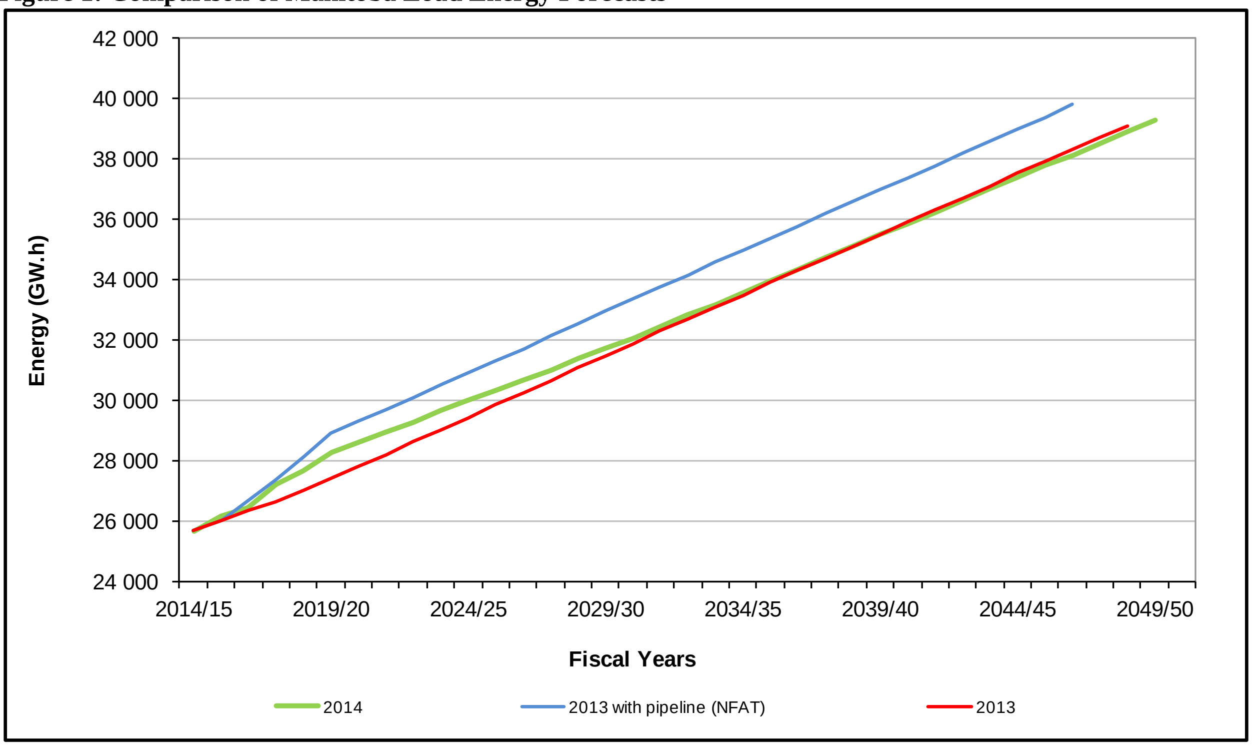
3 DEMAND FOR POWER

Demand for power consists of Manitoba domestic load, which includes residential, commercial and industrial sectors, and requirements from export contracts. The following sections provide a summary of the 2014 energy and capacity forecasts and contract provisions and a discussion of the changes from 2013.

3.1 Electric Load Forecast

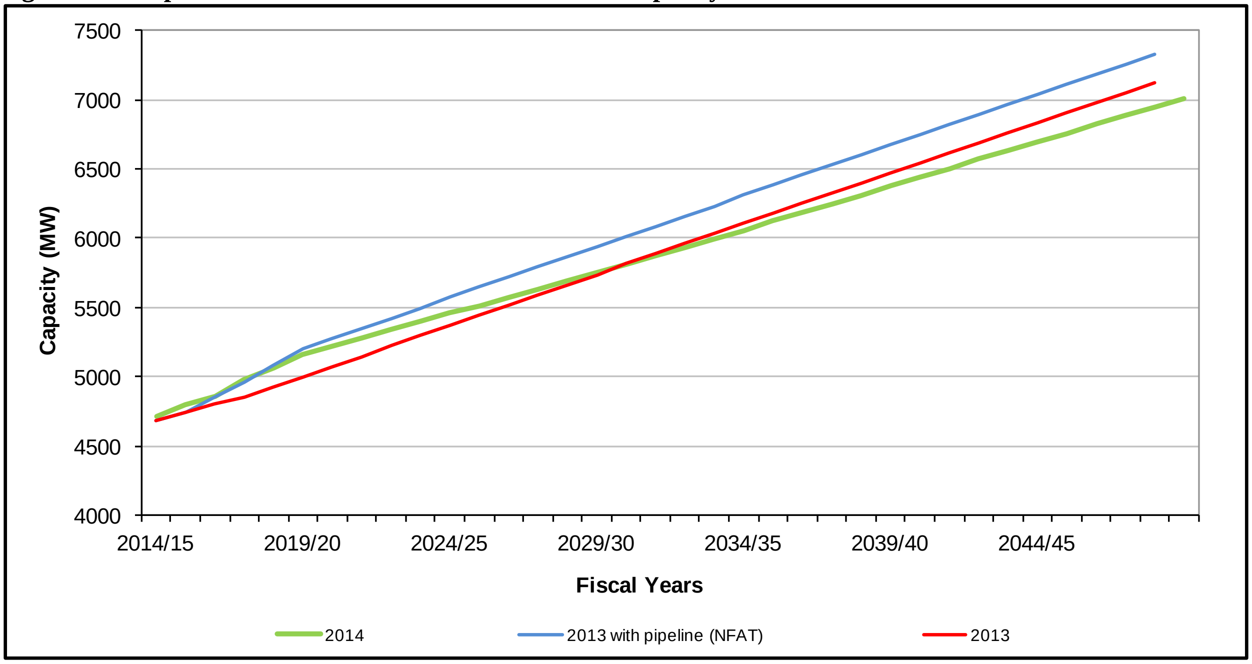
The 2014 Electric Load Forecast, prepared by the Market Forecast Department, provides Manitoba Hydro's forecast of the Manitoba domestic load. As shown in Figure 1, by 2019/20 the 2014 forecast is 850 GW.h higher due to increases to Top Consumers in the pipeline sector and higher Residential customer forecast in the earlier years. By 2032/33 the increase in the 2014 forecast is reduced to 129 GW.h due to an overall lower Residential customer forecast and increased in projected impacts of Codes and Standards. This equates to a 0.4% increase in the forecast of 2032/33, which represents a gain of less than half a year of load growth (1 year = approximately 425 GW.h). The 2014 load forecast is lower than that provided during the NFAT process due to a decrease in forecasted Top Consumers in the pipeline sector and lower residential customer forecast due to increased codes and standards.

Figure 1: Comparison of Manitoba Load Energy Forecasts



As shown in Figure 2, the 2014 Gross Total Peak demand forecast for 2032/33 is down 28 MW compared to the 2013 Load Forecast, less than a half a year of load growth. (1 year = approximately 70 MW). The 2014 load forecast is lower than that provided during the NFAT process due to a decrease in forecasted Top Consumers in the pipeline sector and lower residential customer forecast due to increased codes and standards.

Figure 2: Comparison of Manitoba Load Winter Peak Capacity Forecast



3.2 Demand Side Management

Incremental demand side management (DSM) included in the 2014/15 Power Resource Plan is 582 MW and 2797 GW.h achieved by 2028/29. This is a significant increase from the 2013 PRP (which included 166 MW and 773 GW.h achieved by 2027/28) based on an in-depth review of the market. Incremental DSM included in the Power Resource Plan excludes savings already achieved to date, savings achieved through codes and standards which are included in the Load Forecast, and savings from curtailable rates programming that do not qualify as winter peak capacity or dependable energy.

The forecast submitted for the NFAT analysis included future code savings anticipated to arise through efforts under the commercial New Buildings Program. With the recent Manitoba adoption of the National Energy Code for Buildings, the future energy impacts from these codes have been re-allocated from the Demand Side Management forecast under the 2014 Power Resource Plan and are now reflected in the 2014 Load Forecast due to the formal code implementation in the new construction market.

Figures 3 and 4 show the changes in demand side management assumptions for energy and capacity between the 2013/14 Power Resource Plan, the 2013 NFAT Level 2 DSM, and the 2014/15 Power Resource Plan.

Figure 3: Comparison of DSM Energy Forecasts

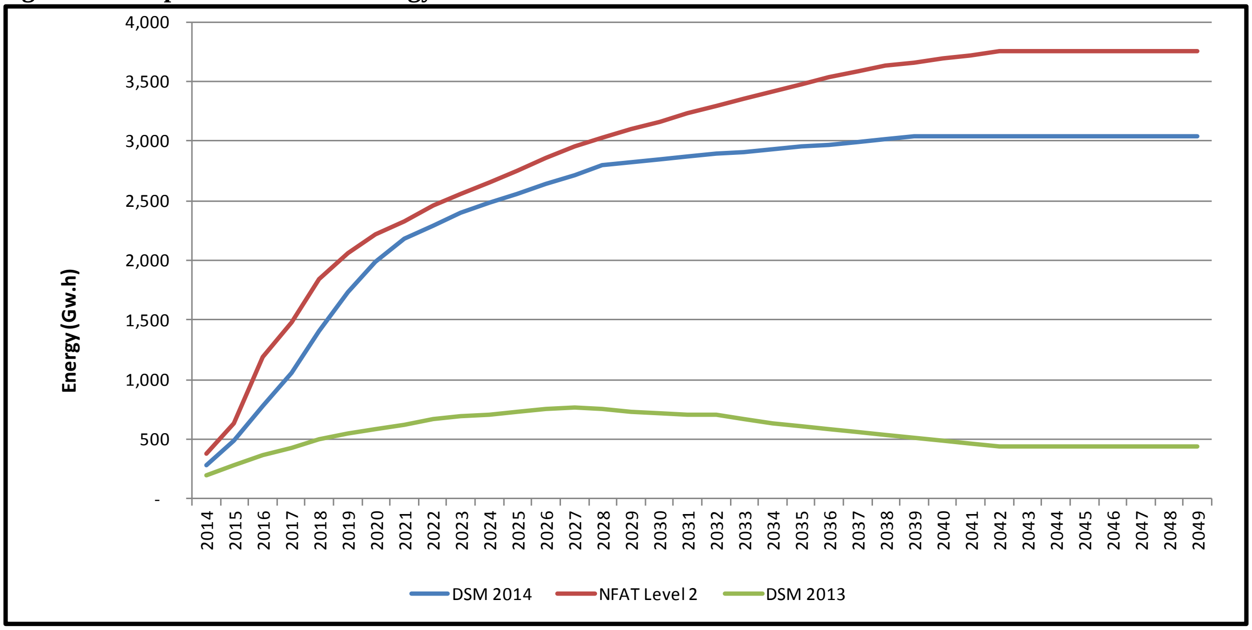
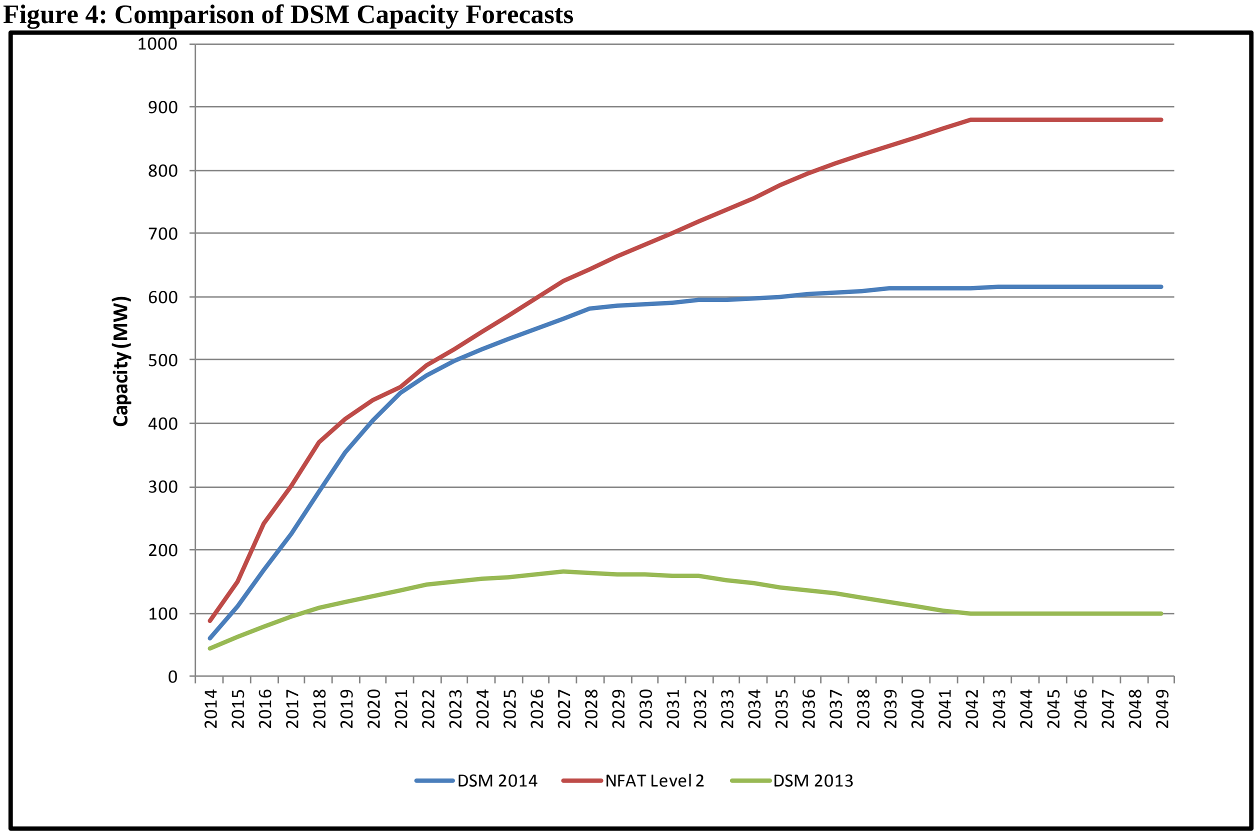


Figure 4: Comparison of DSM Capacity Forecasts



3.3 Long-Term Export Contracts

Long-term dependable export obligations refer to sales that are sourced from dependable energy resources and must be served under all historic water supply conditions including the lowest recorded coincident water supply conditions. Long-term export obligations under dependable flow conditions may be less than the obligation under higher flow conditions and are governed by the terms of each individual contract. In addition, Manitoba Hydro has curtailment rights which give priority to Manitoba load during force majeure events which include drought conditions beyond those for which Manitoba Hydro has planned.

4 SUPPLY OF POWER

This section describes resources that form the base supply of power available to meet Manitoba load requirements and identifies when new base supply resources are required.

Base supply of power is comprised of the following system resources that are common to all development plans being evaluated:

- generating resources owned/operated by Manitoba Hydro including any planned upgrades and committed new resources,
- power purchases from non utility generators in Manitoba,
- imports from neighbouring U.S. utilities,
- projects to replace existing generating resources where plans are in place, and
- reduced losses due to increased HVDC system capacity.

4.1 Manitoba Hydro Operated Facilities – Hydroelectric and Thermal Generation

The following provides a summary of notable assumptions and/or current status updates for specific resources.

Kelsey Rerunnering
The major upgrade of Kelsey G.S. consists of the replacement of all seven turbine runners and generator windings resulting in increased plant capacity of 77 MW and greater utilization of Nelson River inflows. The upgrade was completed in the 2013/14 fiscal year.

The rerunnering project did not significantly increase dependable energy at Kelsey, however there was an increase in average energy of about 350 GW.h/year. Both the capacity gains and energy gains will be confirmed with performance tests. Initial capacity gains shown are estimated prior to performance testing; after performance tests are complete these ratings will be confirmed more accurately.

Brandon Generating Station Unit 5 – Coal-Fired Generation
Availability Assumptions
Brandon Unit 5, Manitoba Hydro's sole remaining coal-fired generating unit, is assumed to remain available until December 31, 2019.

The Climate Change and Emissions Reductions Act
Brandon Unit 5 is governed by the provincial *Climate Change and Emissions Reductions Act* and its subsequent *MR 186/2009,* the *Coal-Fired Emergency Operations Regulation* which restricted coal-fired operation to *"…support emergency operations*".

Operation of Brandon Unit 5 will occur for two main purposes as defined in *MR 186/2009,* the *Coal-Fired Emergency Operations Regulation*: mitigation of adverse water conditions commonly referred to as "drought", and to provide system reliability support.

In order to maintain the effective power generation capability of Unit 5 for either of these purposes, preparation for emergency support will be necessary. It is estimated that operation for this purpose will generate approximately 100 GW.h/year. An additional 25 GW.h/year may be required for emergency service resulting in estimated Unit 5 generation to be in the order of 125 GW.h/year.

Under the conditions previously described, Brandon Unit 5 can continue to operate up to its maximum capability of 811 GW.h/year (northern equivalent). Unit 5 generation is assumed to be available to meet all commitments existing prior to the introduction of the Act. In the future however, Brandon Unit 5 energy shall not be considered available to supply new sales including future long-term dependable export sales.

Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations

Environment Canada's *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* establishes the allowable duration of long-term operation of Brandon Generating Station Unit 5. The federal regulation does not affect operation of Brandon Unit 5 until January 1, 2020. Until that time Brandon will continue to operate as restricted under provincial regulation. Commencing January 1, 2020, the unit can be utilized as a "standby" unit until December 31, 2029. A "standby" unit is permitted to operate to a maximum annual net capacity factor of 9 percent for non-emergency purposes. However starting January 1, 2020, after-the-fact approval of emergency operations is required from the federal Minister of the Environment. Medium term emergencies are limited to a 90 day period but can be extended for another 90 day term. Prolonged, unrestricted operation during a long term, "shortage of fuel" emergency (i.e. drought) after January 1, 2020 is permitted, but requires a declaration by the provincial Minister responsible for the Emergency Measures Act.

Environment Act License Review

As part of an on-going public license review by Manitoba Conservation, Manitoba Hydro submitted an Environmental Impact Statement (EIS) in December 2006.

An update to the 2006 EIS was submitted to Manitoba Conservation in early 2011, which concluded that the original 2006 EIS submission remains valid and applicable to the Environment Act License Review (EALR) process.

Brandon Generating Station Units 6 and 7 – Natural Gas-Fired Generation

The annual firm energy assumption for Brandon Units 6 and 7 is 2354 GW.h . The firm capacity (Winter Peak) remains at 280 MW reflecting the results of Generation Verification Test Capacity (GVTC) testing. Brandon Units 6 and 7 are assumed to remain in service throughout the planning horizon assuming only routine capital investment.

Selkirk Generating Station Units 1 and 2 – Natural Gas-Fired Generation

Selkirk is assumed to remain in operation to the end of the planning horizon assuming only routine capital investment.

Pointe du Bois Generating Station

For the 2014/15 Power Resource Plan the Pointe du Bois powerhouse rebuild is assumed for 2039/40. This is a 10 year deferral from the 2013/14 Power Resource Plan. A review of the life extension of the Pointe de Bois powerhouse has been initiated.

4.2 Committed Resources

Consistent with Provincial approvals stemming from the Needs For and Alternatives To (NFAT) process and environmental regulatory approvals, Keeyask G.S. and a new 500kV US interconnection are included as committed resources.

Keeyask Generating Station

The Keeyask G.S. will be located upstream of the Kettle G.S. on the lower Nelson River with 7 units having a maximum rated total power capacity of 695 MW, which occurs when Stephens Lake is drawn down. There will be a net addition of 630 MW to Manitoba Hydro's Integrated Power System once the Keeyask G.S. is added.

Construction of the Keeyask Generation Project began in July 2014, following receipt of all required provincial and federal licenses, authorizations and permits. The first unit is planned to be in-service in 2019 and with the last unit in-service by the fall of 2022.

4.3 Resources in Regulatory Approval Process

US Interconnection

The new 500 kV US interconnection is capable of 698 MW for import and 883 MW for export. The new interconnection is assumed to have an in-service date of June 1, 2020 which is coincident with the start of the MH–MP250 MW Sale Agreements. The new interconnection received approval through the 2013/14 Need For and Alternatives To (NFAT) process but requires several other Canadian and US regulatory approvals which are expected to be received by late 2016.

4.4 Power Purchases from Manitoba Generators

Wind Generation

Manitoba Hydro has power purchase agreements (PPAs) with three wind producers, St. Leon Energy LP, Algonquin Power, and Pattern Energy Group. These PPA's provide Manitoba Hydro with 771 GW.h of dependable energy on an annual basis. Wind generation is not assigned a capacity value for the purposes of meeting winter peak load as it is not assured to be available at the time of system peak. For planning purposes, contracted purchases of wind generation are assumed to be renewed using the same terms and conditions after the expiration of the current contracts and to extend through to the end of the study period.

Non-Utility Generation

Manitoba Hydro and Kineticor Resource Corp. executed a Term Sheet for the purchase of 11.65 MW of flare gas generated electricity over a 20 year term. This agreement is assumed to add 97 GW.h of dependable energy to Manitoba Hydro's system.

4.5 Imports from Neighbouring Utilities

Manitoba Hydro has long-term seasonal diversity contracts with Northern States Power (NSP) and Great River Energy (GRE) which provide for winter capacity and dependable energy imports during the winter season in exchange for exports of capacity and energy during the summer season.

The diversity agreements combined provide for an exchange of capacity of 550 MW in 2014/15 and remaining at that quantity until 2024/25, then reducing to 200 MW until it expires in 2029/30. In addition to the diversity agreements, Manitoba Hydro has a 500 MW import agreement with NSP which provides access to energy throughout the year but as the contract does not have a capacity component it is not guaranteed for any particular hour.

Manitoba Hydro's firm northbound scheduling limit from the US Midwest Independent System Operator (MISO) market is 700 MW. In 2020, this limit increases to 1398 MW with the addition of the new 500kV interconnection.

4.6 Loss Reduction due to Bipole III

Bipole III continues to be needed to satisfy reliability requirements within Manitoba, and also results in notable reductions in transmission losses prior to new northern generation. Bipole III, routed on the west side of lakes Manitoba and Winnipegosis, is planned for a 2018/19 in-service date.

Bipole III does not provide any new generation, but is expected to reduce the transmission losses which currently exist on the HVDC system. By using all three bipoles to transmit the lower Nelson River generation, rather than just the existing two, the losses are reduced, resulting in 80 MW and 177 GW.h/year of reduced losses under drought conditions. This benefit has been included and is adjusted downward as new northern hydroelectric generation increases the loading.

4.7 Conawapa Generating Station

Conawapa G.S. is planned to be a ten unit plant located downstream of the Limestone G.S. on the Nelson River. The current design rating for Conawapa G.S. is 1485 MW during open water conditions. Initial impoundment of the forebay will reduce Limestone G.S. output by 90 MW, resulting in a net increase in system summer capacity of 1395 MW. Downstream ice conditions will reduce Conawapa G.S. output by approximately 55 MW and similarly ice conditions will further reduce Limestone G.S. by about 40 MW during winter peak conditions resulting in a nominal net system addition of 1300 MW.

The earliest ISD for Conawapa G.S. is 2029/30. In order to achieve the 2029/30 planned ISD, the construction start date is scheduled for January 2021.

Manitoba Hydro is in the process of winding down activities and expenditures for the Conawapa project to a minimal level. While the NFAT process did not result in approval for the Conawapa Project, it 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. It is expected that Manitoba Hydro will only reinitiate Conawapa project activities if future studies and review provide a strong business case.

The 2014/15 Power Resource Plan does not trigger any additional work to protect an in-service date for Conawapa G.S.

5 RESOURCE DEVELOPMENT PLAN

The following is a description of the resource options included in the 2014/15 Power Resource Plan.

The 2014/15 Power Resource Plan includes the following:

Committed Resources:
- Keeyask G.S. (695 MW) with a 2019/20 in-service date (ISD).

Resources in Regulatory Process:
- A new 500 kV US interconnection with a June 2020 ISD.

Proposed Resources:
- Conawapa G.S. (1485 MW) with a 2029/30 ISD,
- A transmission allowance for north–south transmission improvements beyond Bipole III, as required for the combined output of the Keeyask and Conawapa generating stations.

Related Sales
- The MH–MP 250 MW Sale Agreements dated May 2011,
- The WPS 100 MW Sale Agreement dated May 2011,
- The WPS 308 MW Sale Agreement dated Feb 26, 2014,
- The WPS 108 MW Sale Agreement dated Feb 26, 2014,
- The MH 200 MW Energy Purchase Agreement from WPS dated Feb 26, 2014,
- The NSP 125 MW Sale Agreement dated May 2010.

APPENDIX
A. DEPENDABLE SUPPLY & DEMAND

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2014/15 PRP
No New Resources

	Fiscal Year		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
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask							90	630	630	630	630	630	630	630	630	630	630	630	630
1	**Total New Hydro**							90	630	630	630	630	630	630	630	630	630	630	630	630
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New NUG PPA																			
	Contracted																			
	Proposed				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
3	**Total New NUG PPA**				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
4	**Total New Power Resources**	1+2+3			**12**	**12**	**12**	**102**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**
	Base Supply Power Resources																			
	Existing Hydro		5 133	5 172	5 164	5 190	5 195	5 196	5 181	5 172	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167
	Existing Thermal																			
	Brandon Coal - Unit 5		105	105	105	105	105													
	Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Imports		605	605	605	605	605	605	605	605	605	605	605	220	220	220	220	220		
	Proposed Imports																			
	Pointe du Bois Rebuild																			
	Bipole III Reduced Losses						90	90	80	80	80	80	80	80	80	80	80	80	80	80
5	**Total Base Supply Power Resources**		**6 123**	**6 228**	**6 286**	**6 312**	**6 407**	**6 303**	**6 278**	**6 269**	**6 264**	**6 264**	**6 264**	**5 879**	**5 879**	**5 879**	**5 879**	**5 879**	**5 659**	**5 659**
6	**Total Power Resources**	4+5	**6 123**	**6 228**	**6 298**	**6 324**	**6 419**	**6 405**	**6 920**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 301**	**6 301**
	Peak Demand																			
	2014 Base Load Forecast		4 716	4 803	4 861	4 985	5 068	5 166	5 223	5 284	5 342	5 400	5 458	5 516	5 574	5 632	5 690	5 748	5 808	5 869
	Less: 2014 DSM Forecast		- 60	- 111	- 169	- 226	- 293	- 353	- 406	- 449	- 475	- 498	- 517	- 533	- 550	- 566	- 582	- 585	- 589	- 592
7	**Manitoba Net Load**		4 656	4 692	4 692	4 759	4 775	4 813	4 817	4 835	4 867	4 902	4 941	4 983	5 024	5 066	5 108	5 163	5 219	5 277
	Contracted Exports		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	275	275	275
	Proposed Exports																			
8	**Total Exports**		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	275	275	275
9	**Total Peak Demand**	7+8	**5 382**	**5 176**	**5 416**	**5 483**	**5 334**	**5 372**	**5 596**	**5 743**	**5 747**	**5 782**	**5 821**	**5 368**	**5 409**	**5 341**	**5 383**	**5 438**	**5 494**	**5 552**
10	Reserves		513	563	563	571	573	577	578	580	584	588	593	598	603	608	613	620	626	633
11	**System Surplus**	6-9-10	**228**	**489**	**319**	**270**	**512**	**456**	**746**	**588**	**575**	**536**	**492**	**555**	**509**	**572**	**525**	**463**	**181**	**116**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2014/15 PRP
No New Resources

Fiscal Year		2032/33	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																			
New Power Resources																			
New Hydro																			
Conawapa																			
Keeyask		630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
1 **Total New Hydro**		630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New NUG PPA																			
Contracted																			
Proposed		12	12	12	12														
3 **Total New NUG PPA**		12	12	12	12														
4 **Total New Power Resources**	1+2+3	**642**	**642**	**642**	**642**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**	**630**
Base Supply Power Resources																			
Existing Hydro		5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports																			
Proposed Imports																			
Pointe du Bois Rebuild									87	87	87	87	87	87	87	87	87	87	87
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
5 **Total Base Supply Power Resources**		**5 659**	**5 659**	**5 659**	**5 659**	**5 659**	**5 659**	**5 659**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**	**5 746**
6 **Total Power Resources**	4+5	**6 301**	**6 301**	**6 301**	**6 301**	**6 289**	**6 289**	**6 289**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**	**6 376**
Peak Demand																			
2014 Base Load Forecast		5 931	5 995	6 058	6 122	6 185	6 249	6 313	6 376	6 440	6 504	6 567	6 631	6 694	6 758	6 822	6 885	6 949	7 012
Less: 2014 DSM Forecast		- 594	- 596	- 598	- 601	- 604	- 607	- 610	- 613	- 614	- 614	- 615	- 615	- 615	- 615	- 615	- 615	- 615	- 615
7 **Manitoba Net Load**		5 337	5 399	5 460	5 521	5 581	5 642	5 703	5 763	5 826	5 890	5 952	6 016	6 079	6 143	6 207	6 270	6 334	6 397
Contracted Exports		275	275	275															
Proposed Exports																			
8 **Total Exports**		275	275	275															
9 **Total Peak Demand**	7+8	**5 612**	**5 674**	**5 735**	**5 521**	**5 581**	**5 642**	**5 703**	**5 763**	**5 826**	**5 890**	**5 952**	**6 016**	**6 079**	**6 143**	**6 207**	**6 270**	**6 334**	**6 397**
10 Reserves		640	648	655	663	670	677	684	692	699	707	714	722	729	737	745	752	760	768
11 **System Surplus**	6-9-10	**49**	**- 21**	**- 89**	**117**	**38**	**- 30**	**- 98**	**- 79**	**- 149**	**- 221**	**- 290**	**- 362**	**- 432**	**- 504**	**- 576**	**- 646**	**- 718**	**- 789**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2014/15 PRP
No New Resources

	Fiscal Year		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
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask							493	2 974	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
1	**Total New Hydro**							**493**	**2 974**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Nug PPA																			
	Contracted																			
	Proposed				97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
3	**Total New Nug PPA**				**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4			**97**	**97**	**97**	**590**	**3 071**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**
	Base Supply Power Resources																			
	Existing Hydro		21 928	21 924	21 892	21 878	21 880	21 863	21 816	21 775	21 743	21 743	21 733	21 723	21 723	21 713	21 703	21 703	21 693	21 693
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	811	592												
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports		2 730	2 485	2 575	2 575	2 575	2 575	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113
	Proposed Imports																			
	Hydro Adjustment		373	784	844	844	844	844	844	844	844	844	844	406	307	307	307	307	70	
	Market Purchases		337	583	493	493	493	493	958	1 050	1 050	1 050	1 050	2 417	2 671	2 283	2 226	2 259	2 911	3 100
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Pointe du Bois Rebuild																			
	Bipole III Reduced Losses						101	101	177	177	177	177	177	177	177	177	177	177	177	177
6	**Total Base Supply Power Resources**		**30 257**	**30 665**	**30 693**	**30 679**	**30 782**	**30 546**	**31 375**	**31 612**	**31 580**	**31 580**	**31 570**	**31 122**	**31 006**	**30 608**	**30 541**	**30 574**	**30 197**	**30 161**
7	**Total Power Resources**	5+6	**30 257**	**30 665**	**30 789**	**30 775**	**30 878**	**31 135**	**34 446**	**34 712**	**34 680**	**34 680**	**34 670**	**34 221**	**34 105**	**33 707**	**33 640**	**33 673**	**33 297**	**33 261**
	Manitoba Domestic Load																			
	2014 Base Load Forecast		25 639	26 130	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
	Construction Power - Hydro			110	110	110	110	110	83											
	Less: 2014 DSM Forecast		- 283	- 487	- 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
8	**Manitoba Net Load**		**25 356**	**25 753**	**25 766**	**26 228**	**26 365**	**26 627**	**26 678**	**26 754**	**26 988**	**27 221**	**27 483**	**27 754**	**28 022**	**28 289**	**28 555**	**28 878**	**29 210**	**29 550**
	Contracted Exports		3 421	2 631	3 247	3 367	3 166	3 125	3 951	4 604	4 503	4 476	4 476	2 193	2 049	1 634	1 551	1 551	1 389	1 389
	Proposed Exports																			
	Less: Adverse Water			- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 512	- 512	- 512	- 85						
9	**Total Net Exports**		**3 421**	**2 322**	**2 877**	**2 997**	**2 796**	**2 755**	**3 581**	**4 115**	**3 991**	**3 964**	**3 964**	**2 108**	**2 049**	**1 634**	**1 551**	**1 551**	**1 389**	**1 389**
10	**Total Energy Demand**	8+9	**28 777**	**28 075**	**28 643**	**29 225**	**29 161**	**29 382**	**30 259**	**30 869**	**30 979**	**31 185**	**31 447**	**29 862**	**30 071**	**29 923**	**30 106**	**30 429**	**30 599**	**30 939**
11	**System Surplus**	7-10	**1 481**	**2 590**	**2 146**	**1 551**	**1 718**	**1 753**	**4 187**	**3 843**	**3 701**	**3 495**	**3 223**	**4 359**	**4 034**	**3 784**	**3 534**	**3 244**	**2 698**	**2 322**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2014/15 PRP
No New Resources

Fiscal Year		2032/33	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																			
New Power Resources																			
New Hydro																			
Conawapa																			
Keeyask		3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
1 **Total New Hydro**		**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New Nug PPA																			
Contracted																			
Proposed		97	97	97	97														
3 **Total New Nug PPA**		**97**	**97**	**97**	**97**														
4 New Wind																			
5 **Total New Power Resources**	1+2+3+4	**3 100**	**3 100**	**3 100**	**3 100**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**
Base Supply Power Resources																			
Existing Hydro		21 683	21 673	21 673	21 663	21 653	21 653	21 643	21 643	21 633	21 623	21 623	21 613	21 603	21 603	21 593	21 583	21 583	21 573
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
Contracted Imports		1 113	1 113	1 113	186														
Proposed Imports																			
Hydro Adjustment																			
Market Purchases		3 135	3 172	3 208	3 135	3 150	3 187	3 224	3 257	3 295	3 333	3 370	3 408	3 446	3 484	3 522	3 560	3 598	3 636
Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
Pointe du Bois Rebuild									147	237	237	237	237	237	237	237	237	237	237
Bipole III Reduced Losses		177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
6 **Total Base Supply Power Resources**		**30 186**	**30 213**	**30 249**	**29 239**	**29 058**	**29 095**	**29 122**	**29 302**	**29 420**	**29 448**	**29 485**	**29 513**	**29 541**	**29 579**	**29 607**	**29 635**	**29 673**	**29 701**
7 **Total Power Resources**	5+6	**33 286**	**33 313**	**33 349**	**32 339**	**32 061**	**32 098**	**32 125**	**32 305**	**32 423**	**32 451**	**32 488**	**32 516**	**32 544**	**32 582**	**32 610**	**32 638**	**32 676**	**32 704**
Manitoba Domestic Load																			
2014 Base Load Forecast		32 796	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
Construction Power - Hydro					4	12	16	28	8	8	4								
Less: 2014 DSM Forecast		-2 895	-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
8 **Manitoba Net Load**		**29 901**	**30 265**	**30 626**	**30 990**	**31 357**	**31 721**	**32 091**	**32 429**	**32 806**	**33 181**	**33 555**	**33 934**	**34 314**	**34 694**	**35 075**	**35 455**	**35 835**	**36 216**
Contracted Exports		1 389	1 389	1 389	353	145	145	145	145	145	145	145	145	145	145	145	145	145	145
Proposed Exports																			
Less: Adverse Water																			
9 **Total Net Exports**		**1 389**	**1 389**	**1 389**	**353**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**
10 **Total Energy Demand**	8+9	**31 290**	**31 654**	**32 015**	**31 343**	**31 502**	**31 866**	**32 236**	**32 574**	**32 951**	**33 326**	**33 700**	**34 079**	**34 459**	**34 839**	**35 220**	**35 600**	**35 980**	**36 361**
11 **System Surplus**	7-10	**1 995**	**1 658**	**1 333**	**996**	**559**	**232**	**- 111**	**- 269**	**- 528**	**- 875**	**-1 212**	**-1 563**	**-1 915**	**-2 257**	**-2 610**	**-2 962**	**-3 304**	**-3 657**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2014/15 PRP
Recommended Plan (Keeyask 2019, Conawapa 2029)

Fiscal Year		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
Power Resources																			
New Power Resources																			
New Hydro																			
Conawapa																	520	1 040	1 300
Keeyask							90	630	630	630	630	630	630	630	630	630	630	630	630
1 **Total New Hydro**							90	630	630	630	630	630	630	630	630	630	1 150	1 670	1 930
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New NUG PPA																			
Contracted																			
Proposed				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
3 **Total New NUG PPA**				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
4 **Total New Power Resources**	1+2+3			**12**	**12**	**12**	**102**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**1 162**	**1 682**	**1 942**
Base Supply Power Resources																			
Existing Hydro		5 133	5 172	5 164	5 190	5 195	5 196	5 181	5 172	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 143
Existing Thermal																			
Brandon Coal - Unit 5		105	105	105	105	105													
Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports		605	605	605	605	605	605	605	605	605	605	605	220	220	220	220	220		
Proposed Imports																			
Pointe du Bois Rebuild																			
Bipole III Reduced Losses						90	90	80	80	80	80	80	80	80	80	80	80	21	21
5 **Total Base Supply Power Resources**		**6 123**	**6 228**	**6 286**	**6 312**	**6 407**	**6 303**	**6 278**	**6 269**	**6 264**	**6 264**	**6 264**	**5 879**	**5 879**	**5 879**	**5 879**	**5 879**	**5 600**	**5 576**
6 **Total Power Resources**	4+5	**6 123**	**6 228**	**6 298**	**6 324**	**6 419**	**6 405**	**6 920**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**7 041**	**7 282**	**7 518**
Peak Demand																			
2014 Base Load Forecast		4 716	4 803	4 861	4 985	5 068	5 166	5 223	5 284	5 342	5 400	5 458	5 516	5 574	5 632	5 690	5 748	5 808	5 869
Less: 2014 DSM Forecast		- 60	- 111	- 169	- 226	- 293	- 353	- 406	- 449	- 475	- 498	- 517	- 533	- 550	- 566	- 582	- 585	- 589	- 592
7 **Manitoba Net Load**		4 656	4 692	4 692	4 759	4 775	4 813	4 817	4 835	4 867	4 902	4 941	4 983	5 024	5 066	5 108	5 163	5 219	5 277
Contracted Exports		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	614	614	614
Proposed Exports																			
8 **Total Exports**		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	614	614	614
9 **Total Peak Demand**	7+8	**5 382**	**5 176**	**5 416**	**5 483**	**5 334**	**5 372**	**5 596**	**5 743**	**5 747**	**5 782**	**5 821**	**5 368**	**5 409**	**5 341**	**5 383**	**5 777**	**5 833**	**5 891**
10 Reserves		513	563	563	571	573	577	578	580	584	588	593	598	603	608	613	620	626	633
11 **System Surplus**	6-9-10	**228**	**489**	**319**	**270**	**512**	**456**	**746**	**588**	**575**	**536**	**492**	**555**	**509**	**572**	**525**	**644**	**823**	**994**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2014/15 PRP
Recommended Plan (Keeyask 2019, Conawapa 2029)

Fiscal Year		2032/33	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																			
New Power Resources																			
New Hydro																			
Conawapa		1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300
Keeyask		630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
1 **Total New Hydro**		1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930	1 930
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New NUG PPA																			
Contracted																			
Proposed		12	12	12	12														
3 **Total New NUG PPA**		12	12	12	12														
4 **Total New Power Resources**	1+2+3	**1 942**	**1 942**	**1 942**	**1 942**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**	**1 930**
Base Supply Power Resources																			
Existing Hydro		5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143	5 143
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports																			
Proposed Imports																			
Pointe du Bois Rebuild									87	87	87	87	87	87	87	87	87	87	87
Bipole III Reduced Losses		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
5 **Total Base Supply Power Resources**		**5 576**	**5 576**	**5 576**	**5 576**	**5 576**	**5 576**	**5 576**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**	**5 663**
6 **Total Power Resources**	4+5	**7 518**	**7 518**	**7 518**	**7 518**	**7 506**	**7 506**	**7 506**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**	**7 593**
Peak Demand																			
2014 Base Load Forecast		5 931	5 995	6 058	6 122	6 185	6 249	6 313	6 376	6 440	6 504	6 567	6 631	6 694	6 758	6 822	6 885	6 949	7 012
Less: 2014 DSM Forecast		- 594	- 596	- 598	- 601	- 604	- 607	- 610	- 613	- 614	- 614	- 615	- 615	- 615	- 615	- 615	- 615	- 615	- 615
7 **Manitoba Net Load**		5 337	5 399	5 460	5 521	5 581	5 642	5 703	5 763	5 826	5 890	5 952	6 016	6 079	6 143	6 207	6 270	6 334	6 397
Contracted Exports		614	614	614	339														
Proposed Exports																			
8 **Total Exports**		614	614	614	339														
9 **Total Peak Demand**	7+8	**5 951**	**6 013**	**6 074**	**5 860**	**5 581**	**5 642**	**5 703**	**5 763**	**5 826**	**5 890**	**5 952**	**6 016**	**6 079**	**6 143**	**6 207**	**6 270**	**6 334**	**6 397**
10 Reserves		640	648	655	663	670	677	684	692	699	707	714	722	729	737	745	752	760	768
11 **System Surplus**	6-9-10	**927**	**857**	**789**	**995**	**1 255**	**1 187**	**1 119**	**1 138**	**1 068**	**996**	**927**	**855**	**785**	**713**	**641**	**571**	**499**	**428**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2014/15 PRP
Recommended Plan (Keeyask 2019, Conawapa 2029)

	Fiscal Year		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
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																	2 198	4 650	4 650
	Keeyask							493	2 974	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
1	**Total New Hydro**							**493**	**2 974**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**3 003**	**5 201**	**7 653**	**7 653**
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Nug PPA																			
	Contracted																			
	Proposed				97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
3	**Total New Nug PPA**				**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4			**97**	**97**	**97**	**590**	**3 071**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**3 100**	**5 298**	**7 750**	**7 750**
	Base Supply Power Resources																			
	Existing Hydro		21 928	21 924	21 892	21 878	21 880	21 863	21 816	21 775	21 743	21 743	21 733	21 723	21 723	21 713	21 703	21 703	21 693	21 693
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	811	592												
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports		2 730	2 485	2 575	2 575	2 575	2 575	4 244	4 579	4 579	4 579	4 579	3 212	2 941	2 941	2 941	2 941	2 159	2 004
	Proposed Imports																			
	Hydro Adjustment		373	784	844	844	844	844	844	844	844	844	844	406	307	307	307	307	70	
	Market Purchases		337	583	493	493	493	493	216	159	159	159	159	1 527	1 786	1 400	1 346	1 756	2 579	2 734
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Pointe du Bois Rebuild																			
	Bipole III Reduced Losses						101	101	177	177	177	177	177	177	177	177	177	177	261	261
6	**Total Base Supply Power Resources**		**30 257**	**30 665**	**30 693**	**30 679**	**30 782**	**30 546**	**31 375**	**31 612**	**31 580**	**31 580**	**31 570**	**31 123**	**31 012**	**30 616**	**30 552**	**30 962**	**30 840**	**30 770**
7	**Total Power Resources**	5+6	**30 257**	**30 665**	**30 789**	**30 775**	**30 878**	**31 135**	**34 446**	**34 712**	**34 680**	**34 680**	**34 670**	**34 222**	**34 111**	**33 715**	**33 651**	**36 259**	**38 590**	**38 520**
	Manitoba Domestic Load																			
	2014 Base Load Forecast		25 639	26 130	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
	Construction Power - Hydro			110	110	110	110	110	83	10	15	20	30	50	55	80	100	90	30	5
	Less: 2014 DSM Forecast		- 283	- 487	- 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
8	**Manitoba Net Load**		**25 356**	**25 753**	**25 766**	**26 228**	**26 365**	**26 627**	**26 678**	**26 764**	**27 003**	**27 241**	**27 513**	**27 804**	**28 077**	**28 369**	**28 655**	**28 968**	**29 240**	**29 555**
	Contracted Exports		3 421	2 631	3 247	3 367	3 166	3 125	3 951	4 604	4 503	4 476	4 476	2 193	2 049	1 634	1 551	1 930	2 922	2 922
	Proposed Exports																			
	Less: Adverse Water			- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 512	- 512	- 512	- 85						
9	**Total Net Exports**		**3 421**	**2 322**	**2 877**	**2 997**	**2 796**	**2 755**	**3 581**	**4 115**	**3 991**	**3 964**	**3 964**	**2 108**	**2 049**	**1 634**	**1 551**	**1 930**	**2 922**	**2 922**
10	**Total Energy Demand**	8+9	**28 777**	**28 075**	**28 643**	**29 225**	**29 161**	**29 382**	**30 259**	**30 879**	**30 994**	**31 205**	**31 477**	**29 912**	**30 126**	**30 003**	**30 206**	**30 898**	**32 162**	**32 477**
11	**System Surplus**	7-10	**1 481**	**2 590**	**2 146**	**1 551**	**1 718**	**1 753**	**4 187**	**3 833**	**3 685**	**3 474**	**3 192**	**4 310**	**3 985**	**3 712**	**3 445**	**5 361**	**6 428**	**6 043**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2014/15 PRP
Recommended Plan (Keeyask 2019, Conawapa 2029)

Fiscal Year		2032/33	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																			
New Power Resources																			
New Hydro																			
Conawapa		4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650	4 650
Keeyask		3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003	3 003
1 **Total New Hydro**		**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New Nug PPA																			
Contracted																			
Proposed		97	97	97	97														
3 **Total New Nug PPA**		**97**	**97**	**97**	**97**														
4 New Wind																			
5 **Total New Power Resources**	1+2+3+4	**7 750**	**7 750**	**7 750**	**7 750**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**	**7 653**
Base Supply Power Resources																			
Existing Hydro		21 683	21 673	21 673	21 663	21 653	21 653	21 643	21 643	21 633	21 623	21 623	21 613	21 603	21 603	21 593	21 583	21 583	21 573
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
Contracted Imports		2 004	2 004	2 004	1 077	149													
Proposed Imports																			
Hydro Adjustment																			
Market Purchases		2 734	2 734	2 734	3 661	3 257	3 187	3 224	3 257	3 295	3 333	3 370	3 408	3 446	3 484	3 522	3 560	3 598	3 636
Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
Pointe du Bois Rebuild									147	237	237	237	237	237	237	237	237	237	237
Bipole III Reduced Losses		261	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261
6 **Total Base Supply Power Resources**		**30 760**	**30 750**	**30 750**	**30 740**	**29 398**	**29 179**	**29 206**	**29 386**	**29 504**	**29 532**	**29 569**	**29 597**	**29 625**	**29 663**	**29 691**	**29 719**	**29 757**	**29 785**
7 **Total Power Resources**	5+6	**38 510**	**38 500**	**38 500**	**38 490**	**37 051**	**36 832**	**36 859**	**37 039**	**37 157**	**37 185**	**37 222**	**37 250**	**37 278**	**37 316**	**37 344**	**37 372**	**37 410**	**37 438**
Manitoba Domestic Load																			
2014 Base Load Forecast		32 796	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
Construction Power - Hydro					4	12	16	28	8	8	4								
Less: 2014 DSM Forecast		-2 895	-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
8 **Manitoba Net Load**		**29 901**	**30 265**	**30 626**	**30 990**	**31 357**	**31 721**	**32 091**	**32 429**	**32 806**	**33 181**	**33 555**	**33 934**	**34 314**	**34 694**	**35 075**	**35 455**	**35 835**	**36 216**
Contracted Exports		2 922	2 922	2 922	1 886	401	145	145	145	145	145	145	145	145	145	145	145	145	145
Proposed Exports																			
Less: Adverse Water																			
9 **Total Net Exports**		**2 922**	**2 922**	**2 922**	**1 886**	**401**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**
10 **Total Energy Demand**	8+9	**32 823**	**33 187**	**33 548**	**32 876**	**31 758**	**31 866**	**32 236**	**32 574**	**32 951**	**33 326**	**33 700**	**34 079**	**34 459**	**34 839**	**35 220**	**35 600**	**35 980**	**36 361**
11 **System Surplus**	7-10	**5 686**	**5 312**	**4 951**	**5 614**	**5 293**	**4 966**	**4 623**	**4 465**	**4 206**	**3 859**	**3 522**	**3 171**	**2 819**	**2 477**	**2 124**	**1 772**	**1 430**	**1 077**

Section:	Tab 9	Page No.:	p. 7 of 23
Topic:	Energy Supply		
Subtopic:	Domestic Revenues		
Issue:	DSM Impacts		

PREAMBLE TO IR (IF ANY):

IFF MH 14 assumes up to 1730 GWh of DSM savings by 2019/20.

QUESTION:

a) Provide a revised IFF MH 14 with DSM savings reduced by 50% in each year.

b) What would be the change to annual rate increases (from 3.95%) if MH met the same financial targets/retained earnings with 50% DSM achieved.

RATIONALE FOR QUESTION:

This question explores the impact of not achieving DSM targets.

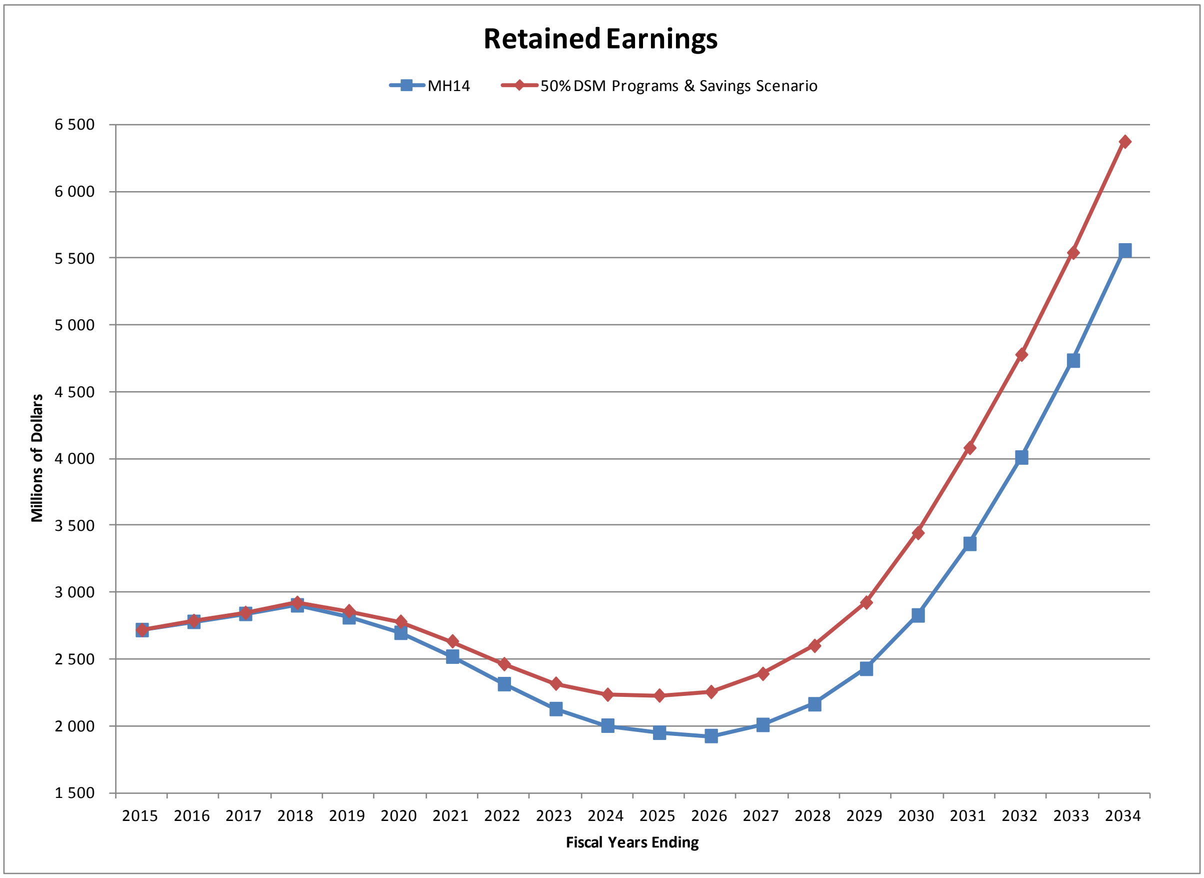
RESPONSE:

The first financial scenario below reflects DSM programs and savings reduced by 50% per year over the forecast period from 2015/16 to 2033/34. This scenario makes the following assumptions:

- DSM utility costs are $0.4 billion lower over the forecast period to 2033/34 compared to MH14 due to the reduction in DSM programs;
- Due to the reduction in DSM savings, new energy resources are required by 2030/31. It is assumed that additional generation is required in 2030/31 and 2032/33 at a total projected cost of $0.4 billion;
- Projected rate increases are the same as MH14;
- Projected Manitoba domestic revenue is $1.7 billion higher (including additional revenue) to 2033/34 compared to MH14 due to the reduction in DSM savings; and

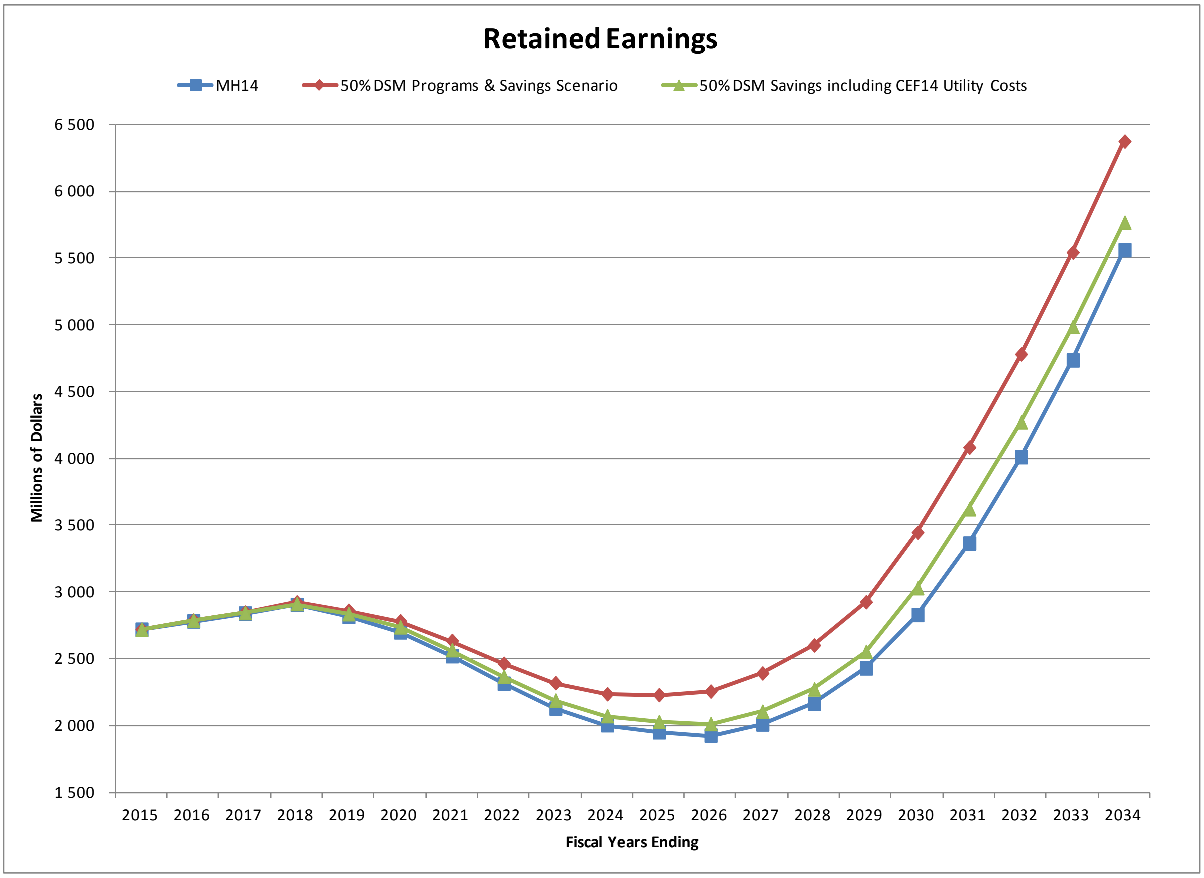
- The reduction in DSM savings results in less energy available for export and reduces projected net export revenue (net of water rentals and fuel and power purchased) by $1.5 billion over the period to 2033/34 compared to MH14.

The following figure shows the retained earnings under MH14 and the 50% DSM programs and savings scenario over the forecast period to 2033/34. The 50% DSM programs and savings scenario results in cumulative projected losses of $694 million over the six year period 2018/19 to 2023/24 compared to $978 million in cumulative losses over the eight year period 2018/19 to 2025/26 in MH14.



An alternative scenario has been prepared with the same assumptions as noted above except that the DSM utility costs are the same as CEF14. This scenario shows the financial impacts of Manitoba Hydro's investment in more aggressive DSM but do not result in the projected savings or customer uptake.

The following figure shows the projected retained earnings of the alternate DSM savings scenario assuming the same utility costs as CEF14 compared to MH14 and the DSM 50% programs and savings scenario.



Projected retained earnings are approximately $200 million higher compared to MH14 due to the shift in energy from export sales to domestic sales and partially offset by the incremental operating and carrying costs for the additional generation required to meet domestic load in 2030/31 and 2032/33. This scenario results in projected cumulative net losses of $898 billion over the eight year period 2018/19 to 2025/26.

Mathematically, the even annual rate increase under the DSM savings scenarios may be reduced from MH14's projected 3.95% rate increases from 2015/16 to 2030/31 to 3.83% and 3.92%, respectively (assumes the 2.0% rate increases 2031/32 to 2033/34 remain the same under both scenarios). However, a reduction to even annual rate increases only serves to increase the cumulative losses projected under both these DSM savings scenarios increasing the risk of rate instability for customers. The proposed and projected 3.95% rate increases are the minimum required to maintain Manitoba Hydro's financial strength and affordable, predictable rates for customers.

The projected financial statements for the DSM 50% program and savings scenario and the alternate DSM 50% savings scenario including the CEF14 utility costs are attached.

Electric Operations 50% DSM Programs & Savings
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 Revenue at approved rates	1 437	1 467	1 480	1 510	1 527	1 547	1 558	1 571	1 586	1 601
Additional General Consumers Revenue	-	58	119	186	256	331	408	489	576	668
BPIII Reserve Account	(30)	(33)	(34)	(36)	(11)	-	-	-	-	-
Extraprovincial	409	428	430	438	459	483	762	880	890	910
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 935	2 009	2 112	2 245	2 375	2 742	2 955	3 068	3 195
EXPENSES										
Operating and Administrative	486	542	552	558	571	586	601	607	619	631
Finance Expense	495	510	546	578	746	878	1 181	1 312	1 317	1 331
Depreciation and Amortization	405	401	420	440	513	512	598	650	718	732
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	131	196	210	216	213	240	271	266	277
Capital and Other Taxes	99	107	120	134	143	144	144	151	151	160
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
	1 754	1 825	1 956	2 043	2 312	2 458	2 899	3 127	3 213	3 274
Non-Controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	122	60	76	(62)	(79)	(147)	(171)	(146)	(83)
* 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										
Debt Ratio	78	82	84	85	86	86	87	89	89	89
Interest Coverage Ratio	1.16	1.17	1.07	1.07	0.95	0.93	0.89	0.87	0.89	0.94
Capital Coverage Ratio	0.98	1.03	0.94	1.11	0.91	0.85	0.84	0.98	1.13	1.26

Electric Operations 50% DSM Programs & Savings
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 Revenue at approved rates	1 617	1 633	1 649	1 665	1 681	1 698	1 716	1 734	1 753	1 772
Additional General Consumers Revenue	765	868	976	1 090	1 210	1 338	1 473	1 553	1 637	1 723
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Extraprovincial	913	840	849	824	817	863	848	816	813	810
Other	16	17	17	18	18	18	19	19	19	20
	3 312	3 358	3 491	3 596	3 726	3 918	4 056	4 123	4 222	4 325
EXPENSES										
Operating and Administrative	644	657	669	683	696	705	725	739	761	776
Finance Expense	1 331	1 324	1 311	1 309	1 290	1 262	1 217	1 161	1 122	1 092
Depreciation and Amortization	746	757	770	784	793	804	816	838	852	878
Water Rentals and Assessments	133	132	133	133	134	138	138	137	137	137
Fuel and Power Purchased	288	286	295	297	306	301	332	353	386	406
Capital and Other Taxes	161	162	163	164	166	168	170	172	175	176
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
	3 313	3 330	3 352	3 382	3 396	3 388	3 406	3 410	3 442	3 475
Non-Controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(6)	27	136	209	324	520	637	698	763	831
* 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										
Debt Ratio	89	89	88	87	86	84	81	79	76	72
Interest Coverage Ratio	1.00	1.02	1.10	1.16	1.25	1.40	1.51	1.58	1.65	1.74
Capital Coverage Ratio	1.31	1.36	1.53	1.64	1.75	2.09	2.16	2.26	2.33	2.43

Electric Operations 50% DSM Programs & Savings
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	2 294	2 596	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	257	265	279	296	306	310	305	293	281
	16 993	18 845	21 753	24 888	26 485	27 553	28 174	27 601	27 662	27 845
LIABILITIES AND EQUITY										
Long Term Debt	11 705	13 808	16 481	18 689	20 977	21 706	22 392	22 555	23 050	23 041
Current and Other Liabilities	2 016	2 124	2 240	2 976	2 265	2 654	2 764	2 228	1 912	2 149
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	2 785	2 845	2 921	2 859	2 779	2 632	2 462	2 316	2 233
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 845	21 753	24 888	26 485	27 553	28 174	27 601	27 662	27 845

Electric Operations 50% DSM Programs & Savings
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	40 581	41 337	42 409	43 537
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 394)	(17 219)	(18 069)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 997	24 943	25 190	25 468
Construction in Progress	322	344	225	254	379	572	472	663	465	255
Current and Other Assets	2 383	2 532	2 778	3 120	3 301	3 623	3 436	4 003	4 689	5 457
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	266	254	243	231	223	220	218	221	226	231
	27 802	27 960	28 204	28 521	28 788	29 215	29 156	29 852	30 582	31 411
LIABILITIES AND EQUITY										
Long Term Debt	22 995	23 598	23 801	23 943	23 876	23 149	23 139	23 143	23 137	22 781
Current and Other Liabilities	2 121	1 611	1 479	1 408	1 380	1 976	1 251	1 207	1 140	1 454
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 227	2 253	2 389	2 598	2 922	3 442	4 079	4 777	5 540	6 371
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 802	27 960	28 204	28 521	28 788	29 215	29 156	29 852	30 582	31 411

Electric Operations 50% DSM Programs & Savings
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	1 965	2 041	2 146	2 254	2 373	2 740	2 953	3 065	3 192
Cash Paid to Suppliers and Employees	(803)	(872)	(947)	(981)	(1 009)	(1 023)	(1 075)	(1 106)	(1 132)	(1 165)
Interest Paid	(511)	(515)	(543)	(589)	(779)	(918)	(1 212)	(1 331)	(1 313)	(1 323)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	593	572	607	501	466	484	544	636	721
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	1 953	2 390	2 990	3 400	2 590	1 600	1 390	600	760	380
Sinking Fund Withdrawals	110	21	-	7	448	203	292	715	165	24
Retirement of Long Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other Financing Activities	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	3 057	1 813	1 469	731	572	443	82
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(1 900)	(2 498)	(3 105)	(3 214)	(2 219)	(1 524)	(986)	(737)	(684)	(683)
Sinking Fund Payment	(125)	(202)	(167)	(243)	(240)	(244)	(261)	(358)	(249)	(255)
Other Investing Activities	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 721)	(3 294)	(3 478)	(2 480)	(1 803)	(1 277)	(1 125)	(963)	(968)
Net Increase (Decrease) in Cash	(270)	(51)	(85)	186	(167)	132	(62)	(9)	115	(166)
Cash at Beginning of Year	133	(137)	(187)	(273)	(87)	(254)	(121)	(184)	(193)	(78)
Cash at End of Year	(137)	(187)	(273)	(87)	(254)	(121)	(184)	(193)	(78)	(244)

Electric Operations 50% DSM Programs & Savings
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	3 309	3 355	3 488	3 593	3 723	3 915	4 052	4 119	4 218	4 322
Cash Paid to Suppliers and Employees	(1 189)	(1 200)	(1 223)	(1 239)	(1 262)	(1 272)	(1 324)	(1 360)	(1 416)	(1 452)
Interest Paid	(1 326)	(1 327)	(1 327)	(1 339)	(1 339)	(1 320)	(1 293)	(1 213)	(1 189)	(1 173)
Interest Received	19	21	35	48	61	70	82	61	75	90
	814	849	974	1 063	1 182	1 393	1 518	1 608	1 689	1 787
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	390	580	190	190	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	293	99	-	-	60	100	700	13	30	-
Retirement of Long Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other Financing Activities	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	250	199	161	163	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(731)	(738)	(740)	(733)	(851)	(882)	(916)	(940)	(868)	(911)
Sinking Fund Payment	(267)	(265)	(273)	(285)	(298)	(306)	(313)	(291)	(302)	(312)
Other Investing Activities	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 028)	(1 034)	(1 039)	(1 044)	(1 175)	(1 214)	(1 256)	(1 257)	(1 197)	(1 250)
Net Increase (Decrease) in Cash	36	14	96	182	(37)	157	221	293	446	491
Cash at Beginning of Year	(244)	(208)	(194)	(98)	85	48	205	426	719	1 165
Cash at End of Year	(208)	(194)	(98)	85	48	205	426	719	1 165	1 655

Electric Operations 50% DSM Savings including CEF14 Utility Costs
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 Revenue at approved rates	1 437	1 467	1 480	1 510	1 527	1 547	1 558	1 571	1 586	1 601
Additional General Consumers Revenue	-	58	119	186	256	331	408	489	576	668
BPIII Reserve Account	(30)	(33)	(34)	(36)	(11)	-	-	-	-	-
Extraprovincial	409	428	430	438	459	483	762	880	890	910
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 935	2 009	2 112	2 245	2 375	2 742	2 955	3 068	3 195
EXPENSES										
Operating and Administrative	486	542	552	558	571	586	601	607	619	631
Finance Expense	495	510	547	581	751	885	1 191	1 323	1 330	1 345
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	131	196	210	216	213	240	271	266	277
Capital and Other Taxes	99	107	121	134	143	144	145	151	151	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
	1 754	1 825	1 960	2 052	2 326	2 477	2 924	3 155	3 245	3 309
Non-Controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	122	56	67	(76)	(98)	(171)	(199)	(178)	(117)
* 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										
Debt Ratio	78	82	84	85	86	87	88	89	90	90
Interest Coverage Ratio	1.16	1.17	1.07	1.07	0.93	0.92	0.87	0.85	0.87	0.91
Capital Coverage Ratio	0.98	1.03	0.93	1.10	0.91	0.84	0.83	0.96	1.11	1.24

Electric Operations 50% DSM Savings including CEF14 Utility Costs
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 Revenue at approved rates	1 617	1 633	1 649	1 665	1 681	1 698	1 716	1 734	1 753	1 772
Additional General Consumers Revenue	765	868	976	1 090	1 210	1 338	1 473	1 553	1 637	1 723
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Extraprovincial	913	840	849	824	817	863	848	816	813	810
Other	16	17	17	18	18	18	19	19	19	20
	3 312	3 358	3 491	3 596	3 726	3 918	4 056	4 123	4 222	4 325
EXPENSES										
Operating and Administrative	644	657	669	683	696	705	725	739	761	776
Finance Expense	1 346	1 343	1 331	1 331	1 313	1 289	1 248	1 194	1 156	1 128
Depreciation and Amortization	767	780	791	804	811	820	831	852	866	892
Water Rentals and Assessments	133	132	133	133	134	138	138	137	137	137
Fuel and Power Purchased	288	286	295	297	306	301	332	353	386	406
Capital and Other Taxes	162	163	164	165	166	168	170	172	175	176
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
	3 351	3 372	3 395	3 424	3 438	3 432	3 452	3 457	3 490	3 526
Non-Controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(44)	(15)	93	167	281	476	591	651	714	781
* 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										
Debt Ratio	90	90	90	89	87	85	83	81	78	75
Interest Coverage Ratio	0.97	0.99	1.07	1.12	1.21	1.36	1.46	1.53	1.60	1.67
Capital Coverage Ratio	1.28	1.33	1.49	1.60	1.72	2.06	2.11	2.22	2.29	2.38

Electric Operations 50% DSM Savings including CEF14 Utility Costs

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	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	27 787	27 965
LIABILITIES AND EQUITY										
Long Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 592	22 755	23 250	23 441
Current and Other Liabilities	2 016	2 145	2 092	3 061	2 192	2 615	2 758	2 253	1 966	2 032
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	2 784	2 841	2 908	2 832	2 734	2 563	2 364	2 186	2 069
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	27 787	27 965

Electric Operations 50% DSM Savings including CEF14 Utility Costs

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	40 581	41 337	42 409	43 537
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 394)	(17 219)	(18 069)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 997	24 943	25 190	25 468
Construction in Progress	322	344	225	254	379	572	472	663	465	255
Current and Other Assets	2 386	2 536	2 785	3 104	3 268	3 733	3 500	4 019	4 654	5 370
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
	27 914	28 062	28 300	28 588	28 833	29 400	29 295	29 944	30 625	31 404
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	2 034	1 556	1 462	1 404	1 396	1 976	1 251	1 207	1 140	1 454
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 025	2 010	2 103	2 269	2 550	3 027	3 618	4 268	4 983	5 763
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 914	28 062	28 300	28 588	28 833	29 400	29 295	29 944	30 625	31 404

Electric Operations 50% DSM Savings including CEF14 Utility Costs
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	1 965	2 041	2 146	2 254	2 373	2 740	2 953	3 065	3 192
Cash Paid to Suppliers and Employees	(803)	(872)	(947)	(981)	(1 009)	(1 024)	(1 075)	(1 107)	(1 132)	(1 165)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(924)	(1 222)	(1 342)	(1 324)	(1 337)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	594	568	602	495	459	473	532	625	706
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 390	600	760	580
Sinking Fund Withdrawals	110	21	-	7	448	204	293	716	165	26
Retirement of Long Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other Financing Activities	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	733	573	443	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 Investing Activities	(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)	(71)	81	(49)	(8)	99	(95)	(40)	88	5
Cash at Beginning of Year	133	(137)	(208)	(127)	(176)	(184)	(85)	(180)	(220)	(132)
Cash at End of Year	(137)	(208)	(127)	(176)	(184)	(85)	(180)	(220)	(132)	(127)

Electric Operations 50% DSM Savings including CEF14 Utility Costs

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	3 309	3 355	3 488	3 593	3 723	3 915	4 052	4 119	4 218	4 322
Cash Paid to Suppliers and Employees	(1 190)	(1 200)	(1 223)	(1 240)	(1 263)	(1 273)	(1 324)	(1 360)	(1 416)	(1 452)
Interest Paid	(1 345)	(1 346)	(1 347)	(1 362)	(1 364)	(1 344)	(1 324)	(1 247)	(1 225)	(1 211)
Interest Received	19	21	35	48	62	71	83	63	77	92
	794	830	952	1 040	1 158	1 369	1 487	1 575	1 655	1 750
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	390	580	190	190	(20)	170	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	296	102	-	-	60	100	700	13	30	-
Retirement of Long Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other Financing Activities	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	253	202	161	163	(45)	178	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(744)	(751)	(752)	(745)	(864)	(895)	(931)	(955)	(884)	(928)
Sinking Fund Payment	(270)	(269)	(277)	(290)	(302)	(312)	(320)	(298)	(309)	(320)
Other Investing Activities	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 044)	(1 050)	(1 055)	(1 061)	(1 192)	(1 233)	(1 277)	(1 279)	(1 220)	(1 274)
Net Increase (Decrease) in Cash	3	(19)	59	143	(79)	314	169	238	388	430
Cash at Beginning of Year	(127)	(124)	(143)	(84)	59	(21)	293	462	700	1 088
Cash at End of Year	(124)	(143)	(84)	59	(21)	293	462	700	1 088	1 518

Section:	Tab 9	**Page No.:**	p. 7 of 23
Topic:	Energy Supply		
Subtopic:	Domestic Revenues		
Issue:	DSM Impacts		

PREAMBLE TO IR (IF ANY):

IFF MH 14 assumes up to 1730 GWh of DSM savings by 2019/20.

QUESTION:

How does MH reconcile higher domestic revenues with changes to customer billings?

RATIONALE FOR QUESTION:

This question explores the impact of not achieving DSM targets.

RESPONSE:

Further to discussions with PUB Counsel, it is Manitoba Hydro's understanding that a response to this Information Request is no longer required.

Section:	Tab 9, App. 11.20	Page No.:	p.10 & p.12 of 23
Topic:	Energy Supply		
Subtopic:	Power Supply		
Issue:	Wind Energy Purchases		

PREAMBLE TO IR (IF ANY):

In the last 3 years MH has reported wind energy purchases of about 900 GWh/year. This energy has added to MH's hydraulic generation surplus.

QUESTION:

Confirm that since Apr 2009, monthly MISO market prices have been less than 50% of the wind energy purchase price in more than 80% of the months.

RATIONALE FOR QUESTION:

This question explores the value, to Manitoba Hydro, of wind energy.

RESPONSE:

Manitoba Hydro confirms the statement; however, Manitoba Hydro notes that MISO energy prices do not reflect the full value of energy purchased by Manitoba Hydro under its long term wind Power Purchase Agreements. The wind PPAs provide Manitoba Hydro with a dependable energy supply whereas the MISO price reflects only the real time or day ahead value of surplus energy in the MISO market.

To value wind energy as surplus energy assumes that wind energy is not serving firm load. This assumption is incorrect in that the majority of wind energy is dependable energy and that a significant portion of hydro energy is surplus energy. Both wind and hydro sources in the Manitoba Hydro system are capable of producing both dependable and surplus energy, and as such each source contributes to serving both dependable load and opportunity exports. As a result valuing energy produced by any of Manitoba Hydro’s generating sources based solely on the MISO price is inappropriate.

Section:	Tab 9, App. 11.20	**Page No.:**	p.10 & p.12 of 23
Topic:	Energy Supply		
Subtopic:	Power Supply		
Issue:	Wind Energy Purchases		

PREAMBLE TO IR (IF ANY):

In the last 3 years MH has reported wind energy purchases of about 900 GWh/year. This energy has added to MH's hydraulic generation surplus.

QUESTION:

Provide a tabulation of the months from Apr 2009 to date of the months when MH was spilling more than 100 GWh/month.

RATIONALE FOR QUESTION:

This question explores the value, to Manitoba Hydro, of wind energy.

RESPONSE:

Table 1 below indicates the months since April 2009 when MH was spilling more than approximately 100 GWh/month due to system spill conditions.

System spill occurs when reservoirs are full and the potential to generate exceeds energy demands. In this circumstance, generation and powerhouse flow must be reduced to balance supply with demand, and additional spill is required.

Table 1: Months with greater than 100 GWh of system spill since April 2009

Fiscal Year Beginning	**Months (inclusive)**
2009	May - October
2010	August - November
2011	April - October
2012	August - September
2013	July - September; November
2014	May - November

Section:	Tab 9, App. 11.20	**Page No.:**	p.10 & p.12 of 23
Topic:	Energy Supply		
Subtopic:	Power Supply		
Issue:	Wind Energy Purchases		

PREAMBLE TO IR (IF ANY):

In the last 3 years MH has reported wind energy purchases of about 900 GWh/year. This energy has added to MH's hydraulic generation surplus.

QUESTION:

Confirm that MH does not typically expect to employ wind energy to meet firm contract commitments.

RATIONALE FOR QUESTION:

This question explores the value, to Manitoba Hydro, of wind energy.

RESPONSE:

Manitoba Hydro includes all sources of electricity as part of its supply portfolio including energy purchased from wind farms to meet the total demand for electricity being experienced. If wind energy is not available then alternative supplies will be used.

Manitoba Hydro does not designate a specific source of electricity to supply specific load. Load, regardless of whether it is from Manitoba or the export market, is supplied by all the resources available on the hydro system. Manitoba Hydro does not specifically track where the supply is coming from (i.e. whether the resource is water or wind) or where it is going to (Manitoba or an export customer).

Section:	Tab 9, App. 11.20 MFR	**Page No.:**	p.15 of 22
Topic:	Energy Supply		
Subtopic:	US Export Sales		
Issue:	Diversity Contract Sales (since 2008)		

PREAMBLE TO IR (IF ANY):

Post 2007/08, MH has made annual Diversity sales as follows:

	Summer (GWh)	Winter (GWh)
2008/09	888	-
2009/10	866	-
2010/11	865	-
2011/12	884	407
2012/13	872	392
2013/14	862	301
2014/15	724	?

QUESTION:

Confirm that MH summer Diversity sales do not include a capacity component.

RATIONALE FOR QUESTION:

This question explores the benefits of the diversity sales agreements to Manitoba Hydro in both winter and summer.

RESPONSE:

Not confirmed.

MH's diversity agreements include both energy and capacity components. MH provides energy and capacity to a counterparty in the summer season and the counterparty provides

MH with energy and capacity in the winter season. The seasonal exchange of capacity benefits both parties by reducing the need to build for capacity in their respective peak demand seasons. Capacity is exchanged at no cost to either party.

The exchange of firm capacity in the existing diversity agreements signed in the early 1990's justified the construction of new firm transmission between Manitoba and Minnesota and the ongoing diversity contracts justify the preservation of this firm transmission service for both exports and imports, including both seasonal diversity and other energy types. This transmission service continues to contribute to MH's overall export revenues while providing reliability benefits for MH's domestic customers.

Section:	Tab 9, App. 11.20 MFR	**Page No.:**	p.15 of 22
Topic:	Energy Supply		
Subtopic:	US Export Sales		
Issue:	Diversity Contract Sales (since 2008)		

PREAMBLE TO IR (IF ANY):

Post 2007/08, MH has made annual Diversity sales as follows:

	Summer (GWh)	Winter (GWh)
2008/09	888	-
2009/10	866	-
2010/11	865	-
2011/12	884	407
2012/13	872	392
2013/14	862	301
2014/15	724	?

QUESTION:

Indicate the average annual unit energy price achieved in each year in (i) summer and (ii) winter from the NSP and GRE Diversity Contracts.

RATIONALE FOR QUESTION:

This question explores the benefits of the diversity sales agreements to Manitoba Hydro in both winter and summer.

RESPONSE:

Seasonal diversity contracts play an important role in Manitoba Hydro's resource plan providing capacity during Manitoba's winter peak season, enabling the construction of transmission, and justifying the preservation of firm transmission service for exports and imports. Seasonal Diversity contracts have the effect of reducing the need for Manitoba Hydro to build for capacity in the winter, but in exchange they increase the need for capacity resources in the summer to meet the export customer's summer peak load.

The seasonal totals of all seasonal diversity energy sold is summarized below.

	Summer (GWh)	**Winter (GWh)**
2008/09	888	-
2009/10	866	-
2010/11	865	-
2011/12	884	371
2012/13	875	404
2013/14	923	309
2014/15	832	93

Please refer to Appendix 11.20 Export and Domestic Revenue MFR 3 for the average annual unit energy price achieved for all energy (including Seasonal Diversity energy) delivered under NEB Permit No. 33 and 34, which are the permits associated with the Seasonal Diversity contracts with NSP and NEB Permit No. 35 which is the permit associated with the Seasonal Diversity contract with GRE.

Section:	Tab 9, App. 11.36	**Page No.:**	p.15 of 22
Topic:	Energy Supply		
Subtopic:	US Export Sales		
Issue:	Diversity Contract Sales (since 2015)		

PREAMBLE TO IR (IF ANY):

MH's Diversity Exchange agreements with NSP and GRE provide winter capacity protection up to 550 MW. They also appear to place a similar summer capacity obligation on MH. This is illustrated in the following example:

Plan (5) Base DSM 2017/18

Transmission Capability — Maximum Tie Line Capacity 1850 MW Existing

	Summer		Winter		
Hydraulic Generation		5100 MW	5100 MW		
	Peak	Average	Peak	Average	
Domestic Demand at Generation	3719 MW	2700 MW	4958 MW	4000 MW	
+ Reserve	419 MW	300 MW	559 MW	500 MW	
	4138 MW	3000 MW	5517 MW	4500 MW	
Hydraulic Generation Available Capacity for 5x16 exports	962-86= 876 MW Firm	2100-190= Ⓣ1910 MW Firm + Opport.	N/A (417 MW)	600-54= 546 MW	
					Annual Totals Peak
Available for Peak CDN Sales	70 MW	70 MW (140 GWh)	70 MW	70 MW (140 GWh)	280 GWh
Committed Firm Obligations	1083 MW (incl. Div.)	1083 MW (1066 GWh)	133 MW (Net of Div.)	483 MW (966 GWh)	2032 GWh
Uncommitted Firm 5x16 sales	222 MW	217 MW (434 GWh)	0	0	434 GWh
Opportunity 5x16 sales	N/A	550 MW (1100 GWh)	N/A	937 MW (874 GWh)	1974 GWh
Total 5x16 US sales		1850 MW (2500 GWh)		1026 MW (1840 GWh)	4340 GWh
Non-Hydraulic 5x16 Thermal or Imports	Ⓓ500 MW (? GWh.)	Ⓒ550 MW	Ⓓ510 MW (? GWh)	Ⓔ550 MW (Div.) (1100 GWh)	1100 GWh additional capacity purchases

Ⓣ 100% of MISO Tie Line Peak Transmission Summer Constraint; 20% in winter

Ⓒ Involves use of Diversity Contract Generation & Transmission Capacity at unknown cost

Ⓓ Requires Firm Thermal/Imports at full Peak Market Price

Ⓔ Involves Diversity Energy Charge at Peak Market Price plus Transmission Adjustment

QUESTION:

Provide a detailed analysis of MH's 2015/16 to 2019/20 forecasts in terms of (i) 5x16 Firm; (ii) 5x16 Uncommitted; (iii) Firm/5x16 Opportunity and (iv) Off-peak Opportunity sales.

RATIONALE FOR QUESTION:

To assess the impact of summer Diversity obligations on export revenues.

RESPONSE:

The information requested is commercially sensitive and has been filed in confidence with the PUB.

Section:	Tab 9, App. 11.36	**Page No.:**	p.15 of 22
Topic:	Energy Supply		
Subtopic:	US Export Sales		
Issue:	Diversity Contract Sales (since 2015)		

PREAMBLE TO IR (IF ANY):

MH's Diversity Exchange agreements with NSP and GRE provide winter capacity protection up to 550 MW. They also appear to place a similar summer capacity obligation on MH. This is illustrated in the following example:

Plan (5) Base DSM 2017/18

Transmission Capability — Maximum Tie Line Capacity 1850 MW Existing

	Summer		Winter		
Hydraulic Generation		5100 MW	5100 MW		
	Peak	**Average**	**Peak**	**Average**	
Domestic Demand at Generation	3719 MW	2700 MW	4958 MW	4000 MW	
+ Reserve	419 MW	300 MW	559 MW	500 MW	
	4138 MW	3000 MW	5517 MW	4500 MW	
Hydraulic Generation Available Capacity for 5x16 exports	962-86= 876 MW Firm	2100-190= Ⓣ1910 MW Firm + Opport.	N/A (417 MW)	600-54= 546 MW	
					Annual Totals Peak
Available for Peak CDN Sales	70 MW	70 MW (140 GWh)	70 MW	70 MW (140 GWh)	280 GWh
Committed Firm Obligations	1083 MW (incl. Div.)	1083 MW (1066 GWh)	133 MW (Net of Div.)	483 MW (966 GWh)	2032 GWh
Uncommitted Firm 5x16 sales	222 MW	217 MW (434 GWh)	0	0	434 GWh
Opportunity 5x16 sales	N/A	550 MW (1100 GWh)	N/A	937 MW (874 GWh)	1974 GWh
Total 5x16 US sales		1850 MW (2500 GWh)		1026 MW (1840 GWh)	4340 GWh
Non-Hydraulic 5x16 Thermal or Imports	Ⓓ500 MW (? GWh.)	Ⓒ550 MW	Ⓓ510 MW (? GWh)	Ⓔ550 MW (Div.) (1100 GWh)	1100 GWh additional capacity purchases

Ⓣ 100% of MISO Tie Line Peak Transmission Summer Constraint; 20% in winter

Ⓒ Involves use of Diversity Contract Generation & Transmission Capacity at unknown cost

Ⓓ Requires Firm Thermal/Imports at full Peak Market Price

Ⓔ Involves Diversity Energy Charge at Peak Market Price plus Transmission Adjustment

QUESTION:

Provide a detailed analysis of Manitoba Hydro's energy and capacity purchase costs from third parties to support these sales in average flow years.

RATIONALE FOR QUESTION:

To assess the impact of summer Diversity obligations on export revenues.

RESPONSE:

As shown in Figure 4 of Appendix 11.48 of this Application, Manitoba Hydro has sufficient system capacity to meet its summer diversity obligations and no capacity imports are required.

Tab 9, Figure 9.3 of this Application shows that under the average of all flow conditions there is sufficient hydro generation to serve Manitoba Hydro's total demand obligations including net load and contracted exports and no energy imports are required.

Section:	Tab 2	Page No.:	April 1, 2014 Interim Application page 11
Topic:	Overview and Reasons for Application		
Subtopic:	Forecast Financial Results		
Issue:	Forecast Operating Results		

PREAMBLE TO IR (IF ANY):

In its interim application MH provided financial information based on IFF13. At the time of filing its application, MH was forecasting a net income of $116 million for 2013/14, $55 million in 2014/15 and $12 million for 2015/16. Financial results for those years are different in this application with MH's electric operations posting a net income at March 31, 2014 of $147 million and forecasting a net income for 2014/15 of $102 million and $59 million in 2015/16. MH's IFF14 vs IF13 analysis in section 3.3.1 is at an aggregate level and excludes 2013/14.

QUESTION:

Please provide a comparative analysis of the forecast financial results similar to Table 5 of the April 2014 interim rate application for each of 2013/14, 2014/15 and 2015/16. The table should show Manitoba Hydro's forecast at the time of the April 2014 interim rate application and compare it with the current forecast/actual data from IFF14. b)Please explain all material differences.

RATIONALE FOR QUESTION:

To understand how MH's forecast for 2013/14 and 2014/15 had changed from when MH sought an interim rate for April 1, 2014.

RESPONSE:

The following table provides a comparative analysis between MH14 to MH13 including actual results for 2013/14.

MH14 vs MH13
Electric Operations
(millions of $)

PUB/MH I-63a

ELECTRIC OPERATIONS
PROJECTED INCOME STATEMENT

For the year ended March 31	2013/14			2014/15			2015/16		
(millions of $)	Actuals	MH13 Forecast	Increase (Decrease)	MH14 Forecast	MH13 Forecast	Increase (Decrease)	MH14 Forecast	MH13 Forecast	Increase (Decrease)
GCR									
-at approved rates *	1 424	1 396		1 437	1 408		1 454	1 423	
-with additional rate increases **	-	-		-	56		57	115	
	1 424	1 396	28	1 437	1 463	(27)	1 512	1 538	(26)
Bipole III Reserve Account	(19)	(18)	(0)	(30)	(21)	(9)	(32)	(22)	(10)
Extraprovincial (net of fuel & power purchased and wate	137	139	(3)	150	118	32	181	77	104
Other Revenue	22	13	9	15	13	2	14	13	1
Total Revenue	1 564	1 530	34	1 572	1 573	(1)	1 674	1 606	69
Operating & Administrative	481	485	(4)	486	494	(8)	542	542	(0)
Finance Expense	435	437	(1)	495	499	(4)	510	514	(3)
Depreciation & Amortization	411	415	(4)	405	440	(35)	401	437	(36)
Capital & Other Taxes	97	93	4	99	101	(2)	107	109	(2)
Corporate Allocation	9	9	-	9	9	(0)	8	9	(0)
Other Expenses	6	-	6	2	-	2	2	-	2
Total Expenses	1 439	1 438	1	1 495	1 543	(47)	1 571	1 611	(40)
Non-Controlling Interest	22	24	(2)	25	24	1	12	18	(6)
Net Income	147	116	31	102	55	48	115	12	103
Retained Earnings (Electric)	2 615	2 584	31	2 717	2 638	79	2 778	2 592	186
Debt to Equity Ratio (consolidated)	76:24	76:24		77:23	78:22		81:19	82:18	
Interest Coverage Ratio (consolidated)	1.28	1.22	0.06	1.17	1.09	0.08	1.17	1.03	0.14
Capital Coverage Ratio (consolidated)	1.35	1.06	0.29	0.99	0.87	0.12	1.05	0.80	0.25

* - assumes 2.75% interim rate increase beginning May 1, 2014 included in MH14
** -with additional rates increases includes the proposed rate 3.95% in 2014/15 for MH13 only and forecast rate 3.95% in 2015/16 for MH14 and MH13

2013/14 Actual vs. MH13 Forecast

Net income from Electric operations was higher than forecast in 2013/14 primarily as a result of higher General Consumers Revenue (GCR) mainly due to the colder winter weather.

2014/15 MH14 Forecast vs. MH13 Forecast

The 2014/15 projected net income from Electric operations is higher in MH14 primarily due to lower depreciation rates resulting from the 2014 Depreciation Study and a reduction to OM&A costs due to the 1% inflationary cost constraint being implemented in 2014/15, one year earlier compared to MH13. In addition, Extraprovincial revenues (net of water rentals and fuel and power purchases) are higher in MH14 compared to MH13 mainly due to the weakening Canadian dollar.

The increase to net income is partially offset by a reduction in GCR resulting from a lower interim rate increase than requested.

2015/16 MH14 Forecast vs. MH13 Forecast

The 2015/16 projected net income from Electric operations is higher in MH14 primarily as a result of higher net Extraprovincial revenue mainly due to the change in assumption from the average of all water flow conditions to median water flows, a weakening Canadian dollar and higher transmission credits, partially offset by lower prices on the export market. In addition, depreciation expense is lower in MH14 primarily due to lower depreciation rates resulting from the 2014 Depreciation Study.

The increase to net income is partially offset by a reduction in GCR resulting from a lower interim rate increase than requested.

Section:	Tab 2	Page No.:	April 1, 2014 Interim Application page 11
Topic:	Overview and Reasons for Application		
Subtopic:	Forecast Financial Results		
Issue:	Forecast Operating Results		

PREAMBLE TO IR (IF ANY):

In its interim application MH provided financial information based on IFF13. At the time of filing its application, MH was forecasting a net income of $116 million for 2013/14, $55 million in 2014/15 and $12 million for 2015/16. Financial results for those years are different in this application with MH's electric operations posting a net income at March 31, 2014 of $147 million and forecasting a net income for 2014/15 of $102 million and $59 million in 2015/16. MH's IFF14 vs IF13 analysis in section 3.3.1 is at an aggregate level and excludes 2013/14.

QUESTION:

Please provide a table of forecast assumptions used in IFF13 with the actual experience for 2013/14.

RATIONALE FOR QUESTION:

To understand how MH's forecast for 2013/14 and 2014/15 had changed from when MH sought an interim rate for April 1, 2014.

RESPONSE:

Please see the following table.

Table of Assumptions

	2013/14		2014/15	
Economic	Actual	MH13	MH14	MH13
Manitoba Consumer Price Index	2.40%	1.80%	1.80%	2.00%
MH Short-term Cdn interest rate	1.37%	2.00%	1.95%	2.15%
MH Long-term Cdn Interest Rate	3.62%	4.75%	4.50%	5.05%
US-CDN Exchange Rate C$/US$	1.05	1.04	1.10	1.03
System Operations				
Demand GW.h	36,982	36,806	36,315	36,140
Manitoba	25,481	25,192	25,321	25,541
Dependable & Short Term Opportunity Exports	10,344	10,673	9,985	9,593
Other and Losses	965	941	1,008	1,005
Supply GW.h	36,982	36,805	36,315	36,140
Hydraulic	35,261	35,143	35,116	34,321
Thermal	131	114	101	132
Imports and Purchases	1,576	1,547	1,098	1,687

Section:	Tab 2	Page No.:	April 1, 2014 Interim Application page 11
Topic:	Overview and Reasons for Application		
Subtopic:	Forecast Financial Results		
Issue:	Forecast Operating Results		

PREAMBLE TO IR (IF ANY):

In its interim application MH provided financial information based on IFF13. At the time of filing its application, MH was forecasting a net income of $116 million for 2013/14, $55 million in 2014/15 and $12 million for 2015/16. Financial results for those years are different in this application with MH's electric operations posting a net income at March 31, 2014 of $147 million and forecasting a net income for 2014/15 of $102 million and $59 million in 2015/16. MH's IFF14 vs IF13 analysis in section 3.3.1 is at an aggregate level and excludes 2013/14.

QUESTION:

Please file a comparative analysis similar to PUB/MH I-5(b) of Manitoba Hydro's April 2014 interim rate application comparing projections at that time against IFF14 actuals and projections for 2013/14, 2014/15 and 2015/16.

RATIONALE FOR QUESTION:

To understand how MH's forecast for 2013/14 and 2014/15 had changed from when MH sought an interim rate for April 1, 2014.

RESPONSE:

Please see the following tables.

Please note that actual values for Balance Sheet and Cash Flow Statement include Manitoba Hydro subsidiaries.

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
For the year ended March 31
(millions of $)

	2013/14			2014/15			2015/16			
	*Actuals	MH13 Forecast	Increase (Decrease)	MH14 Forecast	MH13 Forecast	Increase (Decrease)	MH14 Forecast	MH13 Forecast	Increase (Decrease)	
Assets										
Net Plant in Service	10,684	10,803	(119)	11,487	11,568	(81)	11,900	12,137	(237)	2013/14 - Assets to be placed in-service were deferred to 2014/15 compared to MH13; 2014/15 - lower than forecast MNG&T plant in-service and lower depreciation rates; 2015/16 -deferrals of plant in-service compared to MH13 and lower depreciation rates
Construction in Progress	2,943	2,425	518	3,257	3,296	(38)	4,932	4,743	189	Corresponds to Plant in-service deferrals and MNG&T cash flow forecasts
Other Assets	2,012	2,058	(46)	2,250	2,054	195	2,033	1,890	143	2014/15 - Increased DSM Expenditures, advances to Centra and Inventory levels; 2015/16 -increased DSM expenditures and advances to Centra
	15,639	15,285	354	16,993	16,918	76	18,866	18,770	96	
Liabilities and Equity										
Long Term Debt and Other Liabilities	12,446	12,117	329	13,721	13,664	58	15,959	15,849	111	2013/14 -Higher payables and lower mitigation payments compared to MH13
Contributions	381	380	1	461	412	49	527	443	84	2014/15 - increased customer contributions to construction and BPIII reserve account; 2015/16 - increased customer contributions to construction and BPIII reserve account
Retained Earnings	2,716	2,584	132	2,717	2,638	79	2,778	2,592	186	Net Income Changes to Equity
Accumulated Other Comprehensive Income	96	204	(108)	94	204	(110)	(399)	(115)	(284)	2013/14 & 2014/15 --Unrealized/realized losses on Debt in cash flow hedges and SFI redemptions; 2015/16 same as previous year plus a larger write-off of unamortized pension
	15,639	15,285	354	16,993	16,918	76	18,866	18,770	96	
Financial Ratios										
Equity (Electric)	77:23	76:24		78:22	78:22		82:18	82:18		
Interest Coverage (Electric)	1.25	1.20	0.05	1.16	1.09	0.07	0.86	1.02	(0.16)	
Capital Coverage (Electric)	1.39	1.03	0.36	0.98	0.86	0.12	0.82	0.78	0.04	

*- includes Subsidiaries

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT

For the year ended March 31 (millions of $)	2013/14			2014/15			2015/16			
	*Actuals	MH13 Forecast	Increase (Decrease)	MH14 Forecast	MH13 Forecast	Increase (Decrease)	MH14 Forecast	MH13 Forecast	Increase (Decrease)	
Operating Activities	661	544	117	558	549	9	587	493	94	2013/14 Higher Revenue from cold winter and higher interest received on investments; 2015/16 Exports increased, FP&P decreased
Financing Activities	1,083	1,000	83	1,218	1,616	(398)	2,077	2,261	(185)	2014/15 Debt Retirement offset by lower debt required to finance MNGT; 2015/16 Lower than forecast debt requirement
Investing Activities	(1,634)	(1,786)	152	(2,046)	(2,175)	129	(2,742)	(2,644)	(98)	2013/14 lower than forecast capital spending on MNG&T; 2014/15 - lower forecast spending on Conawapa, BPIII and other projects ; 2015/16 Increased spending on BPIII and DSM partially offset by decreased spending on Conawapa
Net Increase (Decrease) in Cash	110	(243)	353	(270)	(10)	(260)	(78)	111	(188)	
Cash at Beginning of Year	32	25	7	133	(218)	351	(137)	(227)	91	
Cash at End of Year	142	(218)	360	(137)	(227)	91	(214)	(117)	(98)	

*- includes Subsidiaries

Section:	Tab 3: Appendix 3.3	**Page No.:**	Section 5
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Contracts		
Issue:	Updated Contract Commitments		

PREAMBLE TO IR (IF ANY):

NFAT Exhibit # MH-100 sets out the contract sales, contracted surplus energy sales and non-contracted energy sales.

QUESTION:

Provide an updated NFAT Exhibit MH-100 with additional columns to reflect current contract status.

RATIONALE FOR QUESTION:

Export contract revenues are only aggregated in IFF14.

RESPONSE:

Updated NFAT Exhibit MH-100 is included in the tables below including contract status.

Table #1 MH Export Contracts After 2015 – Dependable Capacity & Energy

Customer	Contract Name	Status	Capacity (MW)	Energy Product	Capacity Revenue	Energy Revenue	Total Revenue (Expense)
Minnesota Power	MP 250	Signed	250	5x16			
	MP Energy Exchange	Signed	0				
	MP 50	Signed	50	5x16			
	MP 133	Signed	0				
Northern States Power	NSP125	Signed	125	5x16(S) 5x12(W)			
	NSP 375/325 SPS	Signed	375(S) 325(W)	5x16(S) 5x12(W)			
	NSP 350 Div. Exchge	Signed	350	7x4 (S)			
Wisconsin Public Service	WPS 100 Product A	Signed	100	5x16			
	WPS 100 Product B	Signed	0				
	WPS 108	Signed	108	5x16			
	WPS 308	Signed	308	5x16			
Great River Energy	GRE Div. Exchange	Signed	200	7x4 (S)			
SaskPower	SaskPower 25	Signed	25	5x16			
Total					$1,239M	$4,536M	$5,776M

Table #2 MH Export Contracts After 2015 – Contracted Surplus Energy

Customer	Contract Name	Status	Surplus Energy Product	Energy Revenue
Minnesota Power	MP 250	Signed	2x16	
	MP Energy Exchange	Signed		
	MP 50	Signed	2x16	
	MP 133	Signed		
Northern States Power	NSP125	Signed		
	NSP 375/325 SPS	Signed		
	NSP 350 Div.Exchge	Signed		
Wisconsin Public Service	WPS 100 Product A	Signed	2x16	
	WPS 100 Product B	Signed		
	WPS 108	Signed		
	WPS 308	Signed	2x16	
Great River Energy	GRE Div. Exchange	Signed		
SaskPower	SaskPower 25	Signed	2x16	
Total				$971M

Table #3 MH Export Contracts After 2015 – Non-Contracted Surplus Energy Sales

Customer	Contract Name	Status	Surplus Energy Product	Energy Revenue
Minnesota Power	MP 250	Signed	*7x8*	
	MP Energy Exchange	Signed		
	MP 50	Signed	7x8	
	MP 133	Signed		
Northern States Power	NSP125	Signed	5x4 (W) 2x16 7x8	
	NSP 375/325 SPS	Signed	5x4 (W) 2x16 7x8	
	NSP 350 Div. Exchge	Signed	All but 7x4 (S)	
Wisconsin Public Service	WPS 100 Product A	Signed	7x8	
	WPS 100 Product B	Signed		
	WPS 108	Signed	2x16 7x8	
	WPS 308	Signed	7x8	
Great River Energy	GRE Div. Exchange	Signed	All but 7x4 (S)	
SaskPower	SaskPower 25	Signed		
Total				$3,463M

Table #4 MH Export Contracts After 2015 – Total Revenue

Customer	Contract Name	Status	Capacity Revenue	Energy Revenue	Total Revenue
Minnesota Power	MP 250	Signed			
	MP Energy Exchange	Signed			
	MP 50	Signed			
	MP 133	Signed			
Northern States Power	NSP125	Signed			
	NSP 375/325 SPS	Signed			
	NSP 350 Div. Exchge	Signed			
Wisconsin Public Service	WPS 100 Product A	Signed			
	WPS 100 Product B	Signed			
	WPS 108	Signed			
	WPS 308	Signed			
Great River Energy	GRE Div. Exchange	Signed			
SaskPower	SaskPower 25	Signed			
Total			$1,239M	$8,970M	$10,122M

Section:	Tab 3: Appendix 3.3	**Page No.:**	Section 5
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Contracts		
Issue:	Updated Contract Commitments		

PREAMBLE TO IR (IF ANY):

NFAT Exhibit # MH-100 sets out the contract sales, contracted surplus energy sales and non-contracted energy sales.

QUESTION:

Include in (a) the additional Minnesota Power contract tabled with the Minnesota Public Utilities Commission during the Great Northern Transmission Line Certificate of Need hearing.

RATIONALE FOR QUESTION:

Export contract revenues are only aggregated in IFF14.

RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH-I-64a which includes the MP 133 Energy Sale.

Section:	Tab 3: Appendix 3.3	Page No.:	Section 5
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Contracts		
Issue:	Updated Contract Commitments		

PREAMBLE TO IR (IF ANY):

NFAT Exhibit # MH-100 sets out the contract sales, contracted surplus energy sales and non-contracted energy sales.

QUESTION:

Include in (a) a detailed tabulation of the capacity [MW] and energy [Gwh] included in each contract.

RATIONALE FOR QUESTION:

Export contract revenues are only aggregated in IFF14.

RESPONSE:

The information requested is commercially sensitive and has been filed in confidence with the PUB.

Section:	Tab 4, App. 4.1	Page No.:	CEF 14
Topic:	Capital Expenditure Forecast		
Subtopic:	New Generation & Transmission Project Costs		
Issue:	Consulting & Mitigation Costs		

PREAMBLE TO IR (IF ANY):

MH financial statement note 23 states as follows:

> *To March 31, 2014, $1 001 million (2013 - $984 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.*

QUESTION:

In a format similar to PUB/MH I-10(b) from the 2012 GRA, provide a breakdown of payments by Community cumulative to 2008 and details for each year from 2007/08 to 2013/14, indicating pursuant to which agreement the obligation arose, to which project the costs have been capitalized, and the ongoing annual commitments under each arrangement.

RATIONALE FOR QUESTION:

The annual cost of the financial obligations are material.

RESPONSE:

Manitoba Hydro is unable to disclose the information requested as it can prejudice ongoing and future negotiations. As such, the information has been provided in confidence with the PUB.

Section:	Tab 4, App. 4.1	Page No.:	CEF 14
Topic:	Capital Expenditure Forecast		
Subtopic:	New Generation & Transmission Project Costs		
Issue:	Consulting & Mitigation Costs		

PREAMBLE TO IR (IF ANY):

MH financial statement note 23 states as follows:

> *To March 31, 2014, $1 001 million (2013 - $984 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.*

QUESTION:

Please provide a detail of payments forecast by community for the years 2014/15 to 2023/24.

RATIONALE FOR QUESTION:

The annual cost of the financial obligations are material.

RESPONSE:

Manitoba Hydro does not include in its forecast payments by community, rather information is forecasted at the aggregate level by major capital project. Please see the response to PUB/MH-I-22b that was filed in confidence with the PUB, which outlines forecasted expenditures associated with Joint Development Process & Study costs by major capital project for the period 2015-2024.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14
Topic:	Capital Expenditure Forecast		
Subtopic:	New Generation & Transmission Project Costs		
Issue:	Consulting & Mitigation Costs		

PREAMBLE TO IR (IF ANY):

MH financial statement note 23 states as follows:

> *To March 31, 2014, $1 001 million (2013 - $984 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.*

QUESTION:

Please describe and explain what other mitigation issues are not determinable at this time.

RATIONALE FOR QUESTION:

The annual cost of the financial obligations are material.

RESPONSE:

In the notes to the Corporation's financial statements, the sentence "*There are other mitigation issues, the outcomes of which are not determinable at this time*" is a typical disclaimer included to recognize there are potential mitigation issues which may arise in the future but are undeterminable at the time of the annual report. Given the size, complexity and nature of Manitoba Hydro's operations, it is not possible at this time to predict with any certainty the issues that may arise or their outcomes.

Section:	Tab 4, App. 4.1	**Page No.:**	CEF 14
Topic:	Capital Expenditure Forecast		
Subtopic:	New Generation & Transmission Project Costs		
Issue:	Consulting & Mitigation Costs		

PREAMBLE TO IR (IF ANY):

MH financial statement note 23 states as follows:

> *To March 31, 2014, $1 001 million (2013 - $984 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.*

QUESTION:

Please provide the detailed revenue requirement impact of the mitigation expenditures on the test years.

RATIONALE FOR QUESTION:

The annual cost of the financial obligations are material.

RESPONSE:

Please see the response to PUB/MH-I-65e.

Section:	Tab 4, App. 4.1	Page No.:	CEF 14
Topic:	Capital Expenditure Forecast		
Subtopic:	New Generation & Transmission Project Costs		
Issue:	Consulting & Mitigation Costs		

PREAMBLE TO IR (IF ANY):

MH financial statement note 23 states as follows:

> *To March 31, 2014, $1 001 million (2013 - $984 million) has been recorded to mitigate and compensate for all project-related impacts. These expenditures are included in the costs of the related projects and amortized over the respective remaining lives. There are other mitigation issues, the outcomes of which are not determinable at this time.*

QUESTION:

Please provide the forecast detailed revenue requirement impacts related to mitigation commitments for major generation transmission projects on each year of the 20 year IFF.

RATIONALE FOR QUESTION:

The annual cost of the financial obligations are material.

RESPONSE:

The following table provides the projected revenue requirement (asset amortization and liability accretion to finance expense) and cash flow impacts related to joint development, process and study costs as well as mitigation and community development commitments for major new generation and transmission projects over the 20-year forecast period to 2033/34.

(Millions of Dollars)

	Amortization	Accretion to Finance Expense	Payment*
2015	1.7	1.7	23.8
2016	1.9	2.5	9.2
2017	2.7	2.4	9.3
2018	3.2	2.3	9.4
2019	4.4	3.2	9.2
2020	5.7	3.7	9.3
2021	10.5	7.1	9.4
2022	12.3	8.3	9.4
2023	12.3	8.0	9.4
2024	12.3	7.6	8.9
2025	12.3	7.6	9.0
2026	12.3	7.5	9.0
2027	12.3	7.4	9.1
2028	12.3	7.4	9.2
2029	12.3	7.3	9.3
2030	12.3	7.2	8.1
2031	12.3	7.1	8.2
2032	12.3	7.1	7.8
2033	12.3	7.0	7.9
2034	12.3	7.0	8.0

* The payment reflects the cash outlay and has no impact on projected net income.

Section:	Tab 4 Appendix 4.1	Page No.:	CEF 14 Pg. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	HVDC – System Capabilities		
Issue:	Bipole I,II & III Utilization		

PREAMBLE TO IR (IF ANY):

NFAT PUB/MH I-042(a) Revised calculates the current and future energy usage of the Bipole system.

QUESTION:

Refile NFAT IR PUB/MH I-042 (a) Revised adding to each table the online percentage capacity utilization of total hydraulic generation and percentage capacity utilization of the total HVDC transmission system.

RATIONALE FOR QUESTION:

This IR explores the future usage of the Bipole system.

RESPONSE:

The following provides a reposting of tables from NFAT IR PUB/MH I-042(a) with online percentage capacity utilization of total existing and committed generation and percentage capacity utilization of the total HVDC transmission system.

Bipoles I and II – 2013						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
Kettle	1220	4750	7010	8960	100%	Bipole I	14140 GW.h	1854 MW	309 MW	83%	480	850
Long	1010	3890	5970	7830	100%							
Spruce	1340	5140	7500	9900	100%	Bipole II	15260 GW.h	2000 MW	500 MW	75%	480	850
Limestone												
Total	3570	13780	20480	26690	100%	Total	29400 GW.h	3854 MW	500 MW	87%	960	1700

After Bipole III – 2019 without Keeyask						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
						Bipole I	12540 GW.h	1854 MW	309 MW	83%	250	440
Kettle	1220	4750	7010	8960	100%							
Long Spruce	1010	3890	5970	7830	100%	Bipole II	13520 GW.h	2000 MW	500 MW	75%	250	440
Limestone	1340	5140	7500	9900	100%							
						Bipole III	13520 GW.h	2000 MW	500 MW	75%	250	440
Total	3570	13780	20480	26690	100%	Limit	41610 GW.h	5854 MW	1104 MW	81%	750	1320

After Bipole III – 2022 with Keeyask						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
Keeyask	630	3000	4400	4740	100%	Bipole I	12540 GW.h	1854 MW	309 MW	83%	310	550
Kettle	1220	4750	7010	8960	100%							
Long Spruce	1010	3890	5970	7830	100%	Bipole II	13520 GW.h	2000 MW	500 MW	75%	310	550
Limestone	1340	5140	7500	9900	100%							
						Bipole III	13520 GW.h	2000 MW	500 MW	75%	310	550
Total	4200	16780	24880	31430	100%	Limit	41610 GW.h	5854 MW	1104 MW	81%	930	1650

Section:	Tab 4 Appendix 4.1	**Page No.:**	CEF 14 Pg. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	HVDC – System Capabilities		
Issue:	Bipole I,II & III Utilization		

PREAMBLE TO IR (IF ANY):

NFAT PUB/MH I-042(a) Revised calculates the current and future energy usage of the Bipole system.

QUESTION:

Explain why the addition of Conawapa G.S. in 2029 would reduce the maximum HVDC limit from 48,900 GWh to 46,270 GWh.

RATIONALE FOR QUESTION:

This IR explores the future usage of the Bipole system.

RESPONSE:

The maximum HVDC limit of 48900 GWh reported in NFAT PUB/MH I-042(a) Revised is an unobtainable maximum. The maximum should have been reported as 41600 GWhs which reflects a maximum HVDC loading of 4750MW. Having a single, close coupled HVDC system is limited to a maximum of 4750 MW allowable single point injection into the southern AC system. Having more than 4750 MW of generation on the lower Nelson requires splitting the HVDC system into two, electrically independent systems to ensure that neither system is greater than 4750 MW. The net result of splitting the HVDC system is an increase in maximum overall limit to 5279 MW (46270 GW.h).

Section:	App. 4.1 App. 11.37	**Page No.:**	pp.3 to 8 p.2
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining (Base) Capital Expenditures		
Issue:	Projected Spending Levels		

PREAMBLE TO IR (IF ANY):

In App. 11.37 MH recorded Sustaining Capital (aka Base Capital) spending growing from $375M in 2007/08 to $470M in 2013/14. MH projects a further increase of $100M in 2014/15 to $571M.

QUESTION:

Please confirm the accuracy of the attached table or provide a revised version.

Manitoba Hydro Capital Spending ($M)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	19 Year Total
Major New Generation & Transmission																				
Total CEF14	1,452	1,914	2,463	2,578	1,531	884	426	196	117	110	108	111	98	81	71	61	67	72	99	12,437
Total CEF13	1,377	1,790	1,864	1,858	1,556	1,368	857	1,235	1,794	1,829	1,626	1,506	1,292	847	540	359	259	105	50	22,110
Difference	75	124	599	720	(25)	(484)	(431)	(1,039)	(1,677)	(1,719)	(1,518)	(1,395)	(1,194)	(765)	(470)	(298)	(192)	(34)	49	(9,673)
Power Supply																				
Total CEF14	132	132	132	132	132	132	132	135	137	140	143	146	149	152	155	158	161	164	167	2,730
Total CEF13	136	128	157	143	137	145	117	112	95	101	90	103	103	104	85	122	81	85	85	2,129
Difference	(4)	4	(25)	(11)	(5)	(13)	15	23	42	40	53	43	46	47	70	36	80	79	83	601
Transmission																				
Total CEF14	125	125	125	125	125	125	150	150	150	150	153	156	159	162	166	169	172	176	179	2,842
Total CEF13	186	205	148	105	139	132	163	164	171	99	92	90	89	89	92	84	92	93	93	2,327
Difference	(61)	(80)	(23)	19	(14)	(7)	(13)	(14)	(21)	51	61	66	70	73	74	85	80	83	86	515
Customer Service & Distribution																				
Total CEF14	236	241	268	206	206	206	205	210	214	219	262	258	263	267	285	268	299	298	303	4,714
Total CEF13	236	241	268	182	162	161	159	165	175	252	262	258	263	267	285	268	299	298	303	4,502
Difference	-	-	-	24	44	46	47	45	39	(33)	-	-	-	-	-	-	-	-	-	212
Customer Care & Marketing																				
Total CEF14	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	77
Total CEF13	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	5	72
Difference	0	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	5
Finance & Administration																				
Total CEF14	75	75	55	55	55	55	55	56	57	59	60	61	62	64	65	66	67	69	70	1,182
Total CEF13	76	55	55	35	32	36	38	40	42	39	45	44	44	44	45	42	46	46	46	849
Difference	(1)	20	0	21	23	19	17	17	15	20	14	17	18	20	19	25	22	23	24	333
Base Capital Expenditures																				
CEF14	571	577	585	522	522	522	548	555	563	571	621	625	637	649	675	665	704	711	724	11,545
CEF13	637	632	632	468	474	478	481	484	487	493	493	499	504	509	512	520	522	526	531	9,879
Difference	(66)	(55)	(47)	55	48	45	67	71	76	78	128	126	134	140	163	145	182	185	193	1,666
Total Capital Spending																				
Total CEF14	2,023	2,491	3,048	3,100	2,054	1,406	974	751	679	681	729	735	735	730	745	726	770	782	822	23,982
Total CEF13	2,013	2,422	2,496	2,326	2,031	1,846	1,338	1,719	2,281	2,322	2,119	2,005	1,795	1,355	1,052	879	780	631	580	31,988
Difference	9	69	552	775	23	(439)	(364)	(968)	(1,601)	(1,641)	(1,390)	(1,270)	(1,060)	(625)	(307)	(153)	(10)	151	242	(8,007)

RATIONALE FOR QUESTION:

Base capital is cited by Manitoba Hydro as a justification for rate increases.

RESPONSE:

Please see the following table (several of the values were adjusted for rounding differences).

Manitoba Hydro 2014/15 & 2015/16 General Rate Application
PUB/MH-I-67a

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	19 Year Total
Major New Generation & Transmission																				
CEF14	1,452	1,914	2,463	2,578	1,531	884	426	196	117	110	108	111	98	81	71	61	67	72	98	12,436
CEF13	1,376	1,790	1,864	1,858	1,556	1,368	857	1,235	1,794	1,829	1,625	1,506	1,292	847	540	359	259	105	50	22,109
Diff	75	124	599	720	(25)	(484)	(431)	(1,039)	(1,677)	(1,719)	(1,518)	(1,395)	(1,194)	(765)	(470)	(298)	(192)	(34)	49	(9,673)
Generation Operations																				
CEF14	132	132	132	132	132	132	132	135	137	140	143	146	149	152	155	158	161	164	167	2,730
CEF13	136	128	157	142	137	145	117	112	95	100	90	103	103	104	85	122	81	85	85	2,129
Diff	(4)	4	(25)	(10)	(5)	(13)	15	23	42	40	53	43	46	47	70	36	80	79	83	601
Transmission																				
CEF14	125	125	125	125	125	125	150	150	150	150	153	156	159	162	166	169	172	176	179	2,842
CEF13	186	205	148	106	139	132	163	164	171	99	92	90	89	89	92	84	92	93	93	2,327
Diff	(61)	(80)	(23)	19	(14)	(7)	(13)	(14)	(21)	51	61	66	70	73	74	85	80	83	86	516
Customer Service & Distribution																				
CEF14	236	241	268	206	206	206	206	210	214	219	262	258	263	267	286	268	299	298	303	4,714
CEF13	236	241	268	182	162	160	159	165	175	252	262	258	263	267	286	268	299	298	303	4,502
Diff	-	-	-	24	44	46	47	45	39	(33)	-	-	-	-	-	-	-	-	-	212
Customer Care & Energy Conservation																				
CEF14	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	76
CEF13	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	72
Diff	0	1	1	1	1	1	1	0	(0)	(0)	(0)	0	(0)	(0)	0	(0)	0	0	0	5
Human Resources & Corporate Services																				
CEF14	75	75	55	55	55	55	55	56	57	58	60	61	62	63	64	66	67	68	70	1,177
CEF13	76	55	55	34	32	36	38	39	42	39	45	44	44	44	45	41	45	45	46	845
Diff	(1)	20	0	21	23	19	17	17	15	20	14	17	18	20	19	25	22	23	24	333
Finance & Regulatory																				
CEF14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
CEF13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
Diff	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Base Capital Expenditures																				
CEF14	571	577	585	522	522	523	548	555	563	571	621	624	637	649	675	665	703	711	724	11,545
CEF13	637	631	632	468	474	477	481	484	487	493	493	499	503	508	512	520	521	526	531	9,878
Diff	(66)	(54)	(47)	55	48	45	67	70	76	78	128	126	134	140	163	145	182	185	193	1,667
Total Capital Spending																				
CEF14	2,023	2,491	3,048	3,100	2,053	1,407	974	751	679	681	729	735	735	730	745	726	770	782	822	23,981
CEF13	2,013	2,422	2,496	2,326	2,030	1,845	1,337	1,719	2,281	2,322	2,119	2,005	1,795	1,355	1,052	879	780	631	[illegible]	[illegible]
Diff	9	69	552	774	23	(439)	(364)	(968)	(1,601)	(1,641)	(1,390)	(1,270)	(1,060)	(625)	(307)	(153)	(10)	151	242	(8,006)

Section:	App. 4.1 App. 11.37	Page No.:	pp.3 to 8 p.2
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining (Base) Capital Expenditures		
Issue:	Projected Spending Levels		

PREAMBLE TO IR (IF ANY):

In App. 11.37 MH recorded Sustaining Capital (aka Base Capital) spending growing from $375M in 2007/08 to $470M in 2013/14. MH projects a further increase of $100M in 2014/15 to $571M.

QUESTION:

Explain and justify the $100M increase in annual sustaining capital expenditures with specific reference to:

- Power supply
- Transmission
- Customer service and distribution
- Customer care and monitoring
- Financial and administration

RATIONALE FOR QUESTION:

Base capital is cited by Manitoba Hydro as a justification for rate increases.

RESPONSE:

The increase of $100 million in sustaining capital expenditures is being driven primarily by the impacts of capacity constraints, load growth and aging infrastructure.

The following provides a breakdown of the increase by Business Unit.

	ACTUAL *13/14*	FORECAST *14/15*	CHANGE *Inc/(Dec)*
ELECTRIC			
Generation Operations	$ 115,901	$ 132,000	$ 16,099
Transmission	102,832	125,000	22,168
Customer Service & Distribution	185,747	235,546	49,799
Customer Care & Energy Conservation	3,031	3,171	140
Human Resources & Corporate Services	62,570	75,000	12,430
Finance & Regulatory	29	200	171
TOTAL ELECTRIC SUSTAINING CAPITAL	**$ 470,110**	**$ 570,917**	**$ 100,807**

Generation Operations -
The increase of $16.1 million is due primarily to continued major overhaul work on the Pine Falls and Great Falls units to address impacts of aging infrastructure for assets such as stators and transformers.

Transmission -
The increase of $22.2 million is mainly due to continued construction of the Rockwood New 230-115 kV Station and improvements to the Lake Winnipeg East System as a result of capacity constraints due to existing and/or higher than average load growth in those regions.

Customer Service and Distribution -
The increase of $49.8 million is due to continued construction of the New Madison 115-24 kV Station which is primarily required due to aging plant but also addresses concerns for employee safety, operational contingencies and capacity. In addition, increased capital investment has been forecasted for urban and rural station development to address the overloaded substations and feeder development in the Winnipeg and rural areas as well as expenditures to begin to address impacts associated with aging plant including poles, underground cables, streetlights and manholes.

Human Resources and Corporate Services -
The increase of $12.4 million is primarily due to continued construction of the fleet services building relocated to Rosser Station and the new Ashern and Neepawa Customer Service Centres, necessitated by the Customer Service Operations District Consolidation initiative.

Section:	App. 4.1 App. 11.37	Page No.:	pp.3 to 8 p.2
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining (Base) Capital Expenditures		
Issue:	Projected Spending Levels		

PREAMBLE TO IR (IF ANY):

In App. 11.37 MH recorded Sustaining Capital (aka Base Capital) spending growing from \$375M in 2007/08 to \$470M in 2013/14. MH projects a further increase of \$100M in 2014/15 to \$571M.

QUESTION:

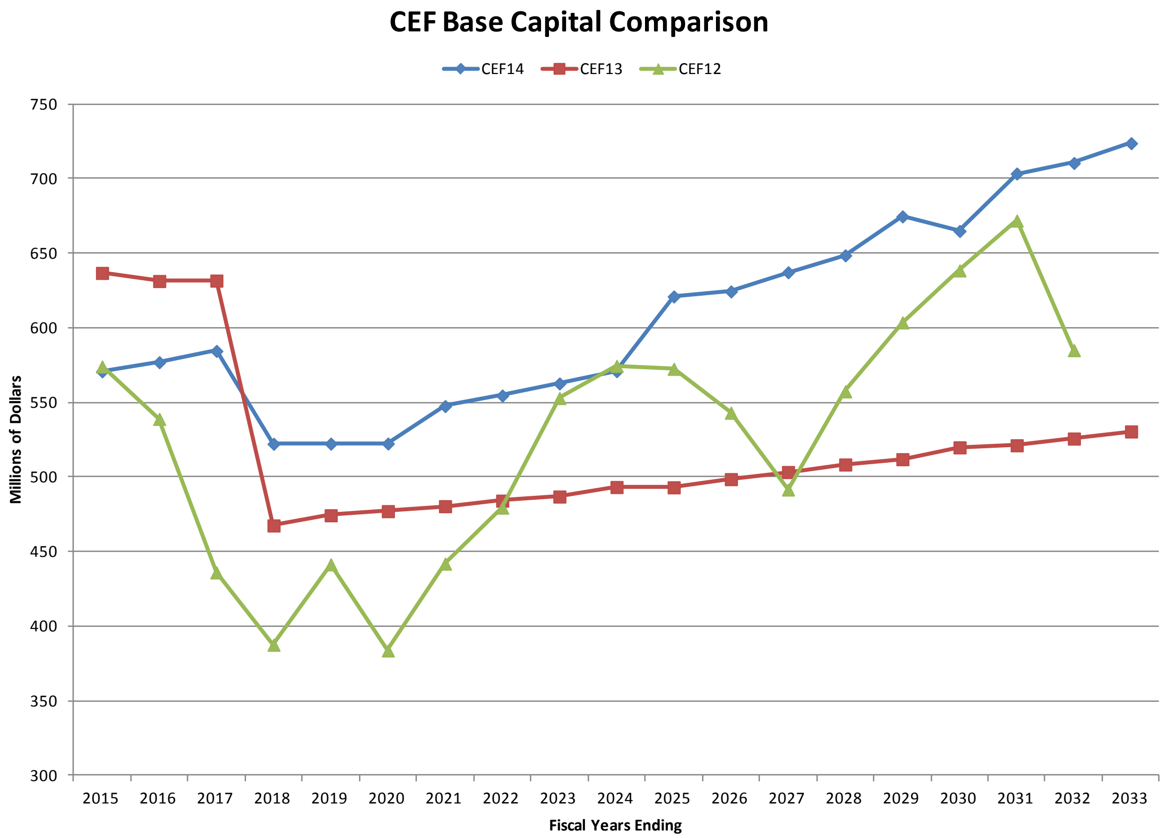
Provide a graphical comparison of Base Capital as depicted annually in each of CEF14, CEF13, CEF12, CEF11-2, CEF10, CEF9 and CEF8.

RATIONALE FOR QUESTION:

Base capital is cited by Manitoba Hydro as a justification for rate increases.

RESPONSE:

Please see the following figure.


CEF Base Capital Comparison
CEF14
CEF13
CEF12
750
700
650
600
550
500
450
400
350
300
Millions of Dollars
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
Fiscal Years Ending

Section:	App. 4.1	**Page No.:**	p.6
Topic:	Capital Expenditure Forecast		
Subtopic:	Pointe du Bois Powerhouse		
Issue:	Status of Project		

PREAMBLE TO IR (IF ANY):

At the NFAT hearing, MH apparently indicated that the Pointe du Bois powerhouse was being deleted from the Power Resource Plan and the Capital Expenditure Forecast.

QUESTION:

Confirm the current status of the Pointe du Bois powerhouse.

RATIONALE FOR QUESTION:

To understand the justification of expenditures on Pointe du Bois.

RESPONSE:

The Pointe du Bois Powerhouse Rebuild was included in the 2014 Power Resource Plan and CEF14 with an in-service date deferred nine years from 2030/31 to 2039/40. The majority of expenditures and the in-service date are projected beyond the 20-year forecast period. The need for and timing of a rebuild is currently under review.

Section:	App. 4.1	**Page No.:**	p.6
Topic:	Capital Expenditure Forecast		
Subtopic:	Pointe du Bois Powerhouse		
Issue:	Status of Project		

PREAMBLE TO IR (IF ANY):

At the NFAT hearing, MH apparently indicated that the Pointe du Bois powerhouse was being deleted from the Power Resource Plan and the Capital Expenditure Forecast.

QUESTION:

Provide an analysis of the powerhouse costs and benefits that would support the CEF14 inclusion of $1.85B in capital cost in the 20 year forecast.

RATIONALE FOR QUESTION:

To understand the justification of expenditures on Pointe du Bois.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH-I-68a.

Section:	App. 4.1	**Page No.:**	p.6
Topic:	Capital Expenditure Forecast		
Subtopic:	Pointe du Bois Powerhouse		
Issue:	Status of Project		

PREAMBLE TO IR (IF ANY):

At the NFAT hearing, MH apparently indicated that the Pointe du Bois powerhouse was being deleted from the Power Resource Plan and the Capital Expenditure Forecast.

QUESTION:

Explain and justify the Pointe du Bois transmission project cost of $114M.

RATIONALE FOR QUESTION:

To understand the justification of expenditures on Pointe du Bois.

RESPONSE:

The Pointe du Bois transmission project includes two phases, each representing approximately half of the budget requirements.

The first phase deals primarily with rebuilding the former Scotland station (renamed to Stafford station) at the existing footprint, to address aging and capacity issues. The aging infrastructure included safety concerns with the location of the 66kV bus structure, poor conditioned transformers, breakers, and bus insulators, and inadequate station ground grid. The station was also in shortage of capacity to serve Winnipeg Central Area load. This phase of the project was completed as of December 2014.

The second phase is mainly addressing aging infrastructure, public safety, and system reliability issues. This phase deals with replacing the four 66kV lines (P1, P2, P3 and P4) from Pointe due Bois station to Rover station. These lines are more than 80 years old and have exceeded their expected serviceable life, thus posing threats to the public safety due to clearance issues and causing operational difficulties. These lines directly serve the Winnipeg Central Area loads and their poor physical state has degraded the reliability of service for that load. The lines will be replaced with a new 115kV line from Pointe du Bois station to Whiteshell station and a new 66kV line from Ridgeway station to Rover station. The in-service is currently planned for 2017/18

Section:	Tab 5:	Page No.:	
Topic:	Financial Results and Forecast		
Subtopic:	Export Revenues		
Issue:	Impact of US Legislation on Export Revenue		

PREAMBLE TO IR (IF ANY):

The Environmental Protection Agency (EPA) has indicated that in the summer of 2015, it intends to issue final rules with respect to existing stationary sources of carbon emissions as part of its Clean Power Plan.

QUESTION:

Has Manitoba Hydro performed an assessment regarding the impact of the Clean Power Plan on Manitoba Hydro? If yes, what are the conclusions of the assessment?

RATIONALE FOR QUESTION:

This question explores the impact of regulatory changes in the U.S. on Manitoba Hydro's exports.

RESPONSE:

On June 2, 2014, the U.S. Environmental Protection Agency (EPA), announced its proposed Clean Power Plan to cut carbon pollution from power plants. Manitoba Hydro has reviewed the U.S. EPA's draft Clean Power Plan and followed various related discussions. The over 700 page draft is written as a discussion document, asking for comment on a number of different alternative approaches and components that could be used to form a final rule. To date, the EPA has received over 3.8 million comments on its draft rule and supplemental materials. In multiple public forums, senior EPA officials have indicated that various components of the draft rule will change based on the extensive feedback received. The final rule is expected to be released during the summer of 2015.

The EPA indicated that across the US by 2030, the Clean Power Plan will help cut carbon emissions from the power sector by 30 percent from 2005 levels, while starting to make progress toward meaningful reductions in 2020. Under the draft plan, each state has a unique emission intensity reduction target to meet by 2030. Following the release of the final rule, 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.

If it is ultimately implemented, it is anticipated that this regulation will impact the U.S. generation mix, carbon emissions and U.S. electricity prices. The EPA's regulatory impact analysis of the proposed plan projected that approximately 46 to 49 GW of additional coal-fired generation (about 19% of all coal-fired capacity and 4.6% of total generation capacity in 2020) may be removed from operation by 2020.

The impact of ongoing business and regulatory environment changes on the electricity markets is assessed annually. Environmental regulations including the Clean Power Plan are one of many factors considered by the electricity export market consultants engaged by Manitoba Hydro.

While the draft Clean Power Plan acknowledged that electricity imported from other countries such as Canada plays a role in U.S. electricity markets, it did not propose if or how this electricity could be treated under this rule. The potential role for Canadian hydropower will depend on the content of the final rule and implementation plans of Manitoba Hydro's key export states.

Section:	Tab 5:	**Page No.:**	
Topic:	Financial Results and Forecast		
Subtopic:	Export Revenues		
Issue:	Impact of US Legislation on Export Revenue		

PREAMBLE TO IR (IF ANY):

The Environmental Protection Agency (EPA) has indicated that in the summer of 2015, it intends to issue final rules with respect to existing stationary sources of carbon emissions as part of its Clean Power Plan.

QUESTION:

Please explain how the proposed changes will impact MH's emergency operation of its Brandon Coal Plant.

RATIONALE FOR QUESTION:

This question explores the impact of regulatory changes in the U.S. on Manitoba Hydro's exports.

RESPONSE:

The proposed draft rules would not affect operations of Brandon Unit 5.

Brandon Unit 5 currently operates subject to the terms and conditions of its Manitoba Environment Act Licence (No. 1703 R) and the Coal-Fired Emergency Operations Regulation (MR 186/2009) pursuant to Manitoba's Climate Change and Emissions Reductions Act (C135).

Section:	Tab 5:	**Page No.:**	
Topic:	Financial Results and Forecast		
Subtopic:	Export Revenues		
Issue:	Impact of US Legislation on Export Revenue		

PREAMBLE TO IR (IF ANY):

The Environmental Protection Agency (EPA) has indicated that in the summer of 2015, it intends to issue final rules with respect to existing stationary sources of carbon emissions as part of its Clean Power Plan.

QUESTION:

Please explain how this rule may impact the level of US export sales in MISO over the short, medium and long term?

RATIONALE FOR QUESTION:

This question explores the impact of regulatory changes in the U.S. on Manitoba Hydro's exports.

RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH-I-69a.

Section:	Tab 5:	**Page No.:**	
Topic:	Financial Results and Forecast		
Subtopic:	Export Revenues		
Issue:	Impact of US Legislation on Export Revenue		

PREAMBLE TO IR (IF ANY):

The Environmental Protection Agency (EPA) has indicated that in the summer of 2015, it intends to issue final rules with respect to existing stationary sources of carbon emissions as part of its Clean Power Plan.

QUESTION:

How could the rule change impact each individual state that MH exports to (Wisconsin, Minnesota and North Dakota)?

RATIONALE FOR QUESTION:

This question explores the impact of regulatory changes in the U.S. on Manitoba Hydro's exports.

RESPONSE:

As explained in Manitoba Hydro's response to PUB/MH-I-69(a), under the draft Clean Power Plan, individual states will have different emission reduction targets allocated to them by the US EPA and take different approaches to meeting these targets, including how they may treat Canadian hydropower imports as compliance mechanisms.

Section:	Tab 5:	Page No.:	
Topic:	Financial Results and Forecast		
Subtopic:	Export Revenues		
Issue:	Impact of US Legislation on Export Revenue		

PREAMBLE TO IR (IF ANY):

The Environmental Protection Agency (EPA) has indicated that in the summer of 2015, it intends to issue final rules with respect to existing stationary sources of carbon emissions as part of its Clean Power Plan.

QUESTION:

What are the US regulatory barriers that could limit MH's ability to increase its US export sales?

RATIONALE FOR QUESTION:

This question explores the impact of regulatory changes in the U.S. on Manitoba Hydro's exports.

RESPONSE:

The Clean Power Plan poses no specific barriers to increased export sales as it is currently drafted. For additional context on the implications of the Clean Power Plan please refer to Manitoba Hydro's response to PUB/MH-I-69a.

Section:	Tab 5:	**Page No.:**	
Topic:	Financial Results and Forecast		
Subtopic:	Export Revenues		
Issue:	Impact of US Legislation on Export Revenue		

PREAMBLE TO IR (IF ANY):

The Environmental Protection Agency (EPA) has indicated that in the summer of 2015, it intends to issue final rules with respect to existing stationary sources of carbon emissions as part of its Clean Power Plan.

QUESTION:

How will the rule change impact the electricity imported into Manitoba?

RATIONALE FOR QUESTION:

This question explores the impact of regulatory changes in the U.S. on Manitoba Hydro's exports.

RESPONSE:

The initial draft of the Clean Power Plan does not change the market rules for importing electricity into Manitoba. As explained in Manitoba Hydro's response to PUB/MH-I-69(a), if it is ultimately implemented, it is anticipated that this regulation will impact the U.S. generation mix, carbon emissions and U.S. electricity prices. To the extent the Clean Power Plan achieves its goal of cutting carbon emissions from existing power plants in the U.S., Manitoba Hydro expects that electricity imports may tend to have on average lower carbon emissions than they currently do.

Section:	Tab 5: Section5.14	Page No.:	45
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expenditures		
Issue:	Cost Containment Initiatives		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table indicating the annual savings MH is forecasting from each of its cost containment initiatives.

RATIONALE FOR QUESTION:

The effectiveness of cost containment measures impacts revenue requirement.

RESPONSE:

Section 5.14 identifies significant initiatives that are intended to result in direct cost reductions, cost avoidance and future savings for both operating and capital expenditures in order to maintain the proposed 3.95% rate increases. In addition to these initiatives, the Corporation continually pursues productivity efficiencies and process improvements.

The impact of these measures is in Manitoba Hydro's ability to hold the average annual OM&A increase to 1% over the 2014/15 to 2021/22 forecast period (excluding accounting changes and increases associated with new major generation and transmission projects coming into service).

The majority of Manitoba Hydro's operating costs are salaries, overtime and benefits and as such, in order to achieve a 1% average annual increase reductions in staffing levels are required. Manitoba Hydro's response to PUB/MH-I-70b provides the estimated annual and cumulative savings associated with the reduction of operational positions.

Expected savings from other cost containment initiatives that seek to streamline processes through the use of technology or other measures are not easily quantifiable.

Section:	Tab 5: Section5.14	**Page No.:**	45
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expenditures		
Issue:	Cost Containment Initiatives		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the supporting calculations around the estimated savings due to targeted attrition.

RATIONALE FOR QUESTION:

The effectiveness of cost containment measures impacts revenue requirement.

RESPONSE:

Please see the following table which demonstrates the operational position reductions and the annual and cumulative savings. The annual savings assumes the position reductions will be realized throughout each year. The cumulative savings will be fully realized in 2017/18.

	2014/15	2015/16	2016/17	Cumulative
President & CEO	2	2	2	6
General Counsel & Corporate Secretary	1	1	1	3
Human Resources & Corporate Services	33	27	21	81
Corporate Relations	3	2	1	6
Finance & Regulatory	4	3	3	10
Generation Operations	9	12	6	28
Major Capital Projects	1	1	-	2
Transmission	30	18	42	90
Customer Service & Distribution	46	19	13	78
Customer Care & Energy Conservation	16	6	5	27
Annual Commitment	146	91	94	331

	2014/15	2015/16	2016/17	2017/18
Annual Savings (000 000s)	$ 7.3	$ 12.3	$ 10.0	$ 5.1
Cumulattive Annual Savings (000 000s)	7.3	19.3	29.7	35.8

Section:	5	Page No.:	Interim Application PUB/MH I-9
Topic:	Financial Results and Forecast		
Subtopic:	Weather Impacts		
Issue:	Heating Degree Day		

PREAMBLE TO IR (IF ANY):

Heating Degree Day (HDD) differences between forecast and normal impact Manitoba Hydro's financial results. MH has previously indicated that 1 HDD represents $55,000 in domestic revenues.

QUESTION:

Please provide a description of HDD and how it is determined.

RATIONALE FOR QUESTION:

This question explores the impact of weather on Manitoba Hydro's revenues.

RESPONSE:

Degree Days Heating (DDH) is the number of degrees that a day's average temperature is colder than 14 degrees Celsius and is based on the average of the high and low temperature of the day. The DDH for each day is calculated as follows:

If Average Temperature < 14, then DDH = 14 – Average Temperature
If Average Temperature = 14 or more, then DDH = 0
Where: Average Temperature = (Daily high + Daily low) / 2

Total DDH = sum of DDH over all days

Section:	5	**Page No.:**	Interim Application PUB/MH I-9
Topic:	Financial Results and Forecast		
Subtopic:	Weather Impacts		
Issue:	Heating Degree Day		

PREAMBLE TO IR (IF ANY):

Heating Degree Day (HDD) differences between forecast and normal impact Manitoba Hydro's financial results. MH has previously indicated that 1 HDD represents $55,000 in domestic revenues.

QUESTION:

Provide an update to PUB/MH I-9 from Manitoba Hydro's April 2014 interim rate application for the HDD comparison between what was forecast in IFF13 for 2013/14 and 2014/15 with actual/updated forecast results set out in IFF14 for those years.

RATIONALE FOR QUESTION:

This question explores the impact of weather on Manitoba Hydro's revenues.

RESPONSE:

The following table displays the Degree Day Heating (DDH) that occurred in the 2013/14 and 2014/15 fiscal year compared with the normal DDH (25 year rolling average) expected for both IFF13 and IFF14.

Month	Actual	IFF13 Normal	IFF14 Normal
Apr-13	482	295	
May-13	116	121	
Jun-13	13	18	
Jul-13	2	2	
Aug-13	1	5	
Sep-13	32	71	
Oct-13	294	277	
Nov-13	592	554	
Dec-13	1,078	845	
Jan-14	1,034	944	
Feb-14	949	786	
Mar-14	826	625	
Year Total	5,420	4,541	
Apr-14	411	295	303
May-14	135	121	122
Jun-14	5	18	18
Jul-14	3	2	2
Aug-14	3	5	5
Sep-14	64	71	69
Oct-14	227	277	276
Nov-14	684	554	556
Dec-14	744	845	855
Jan-15	858	944	948
Feb-15	N/A	786	785
Mar-15	N/A	625	630
Year Total	3,133	4,541	4,570

Section:	5	Page No.:	Interim Application PUB/MH I-9
Topic:	Financial Results and Forecast		
Subtopic:	Weather Impacts		
Issue:	Heating Degree Day		

PREAMBLE TO IR (IF ANY):

Heating Degree Day (HDD) differences between forecast and normal impact Manitoba Hydro's financial results. MH has previously indicated that 1 HDD represents $55,000 in domestic revenues.

QUESTION:

Please explain the financial impact of any differences between forecast and actual HDD on 2013/14 actual results and forecast 2014/15 results.

RATIONALE FOR QUESTION:

This question explores the impact of weather on Manitoba Hydro's revenues.

RESPONSE:

$55,000 per one degree day heating (DDH) represents the approximate financial impact of cold weather on Manitoba Hydro's financial results. The following table displays the impact of cold weather for the months of 2013/14 and 2014/15 from the forecast DDH in IFF13.

Month	Actual DDH	IFF13 Normal DDH	Financial Impact of Difference
Apr-13	482.4	294.7	$10,323,500
May-13	116.3	120.6	-$236,500
Jun-13	13.4	17.9	-$247,500
Jul-13	1.6	1.5	$5,500
Aug-13	1.1	4.7	-$198,000
Sep-13	32.2	70.9	-$2,128,500
Oct-13	294.0	277.3	$918,500
Nov-13	592.0	554.4	$2,068,000
Dec-13	1,078.3	845.4	$12,809,500
Jan-14	1,033.5	943.5	$4,950,000
Feb-14	949.4	785.6	$9,009,000
Mar-14	825.9	624.8	$11,060,500
Year Total	5,420.1	4,541.3	$48,334,000
Apr-14	411.1	294.7	$6,402,000
May-14	134.8	120.6	$781,000
Jun-14	4.6	17.9	-$731,500
Jul-14	2.7	1.5	$66,000
Aug-14	3.3	4.7	-$77,000
Sep-14	63.6	70.9	-$401,500
Oct-14	226.6	277.3	-$2,788,500
Nov-14	684.2	554.4	$7,139,000
Dec-14	743.7	845.4	-$5,593,500
Jan-15	858.1	943.5	-$4,697,000
Feb-15	N/A	785.6	
Mar-15	N/A	624.8	
Year Total	3,132.7	4,541.3	$99,000

Section:	Tab 5: Appendix 5.1	Page No.:	Financial Results and Forecast
Topic:	OM&A Expense		
Subtopic:	Changes in OM&A Expense		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide an update to PUB/MH I-9 (c) from Manitoba Hydro's April 2014 interim application comparing the OM&A by cost element for the nine months ending December 31, 2014 with the prior year period and explain any material changes.

RATIONALE FOR QUESTION:

This question seeks an update on OM&A expense from what was filed in the last rate filing.

RESPONSE:

Please see the attached table comparing the 9 months ended December 31, 2013 versus the 9 months ended December 31, 2014. Variances over 5% and $500,000 have been explained.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	Nine Months Ended December 31				
	2014	**2013**	**Change**	**%**	**Ref**
Wages & Salaries	$ 370,234	$ 358,361	$ 11,873	3	
Overtime	53,195	45,203	7,992	18	1
Employee Benefits	111,573	108,142	3,431	3	
Employee Safety & Training	3,573	2,815	758	27	2
Travel Expenses	22,504	23,297	(793)	(3)	
Motor Vehicle	22,912	21,331	1,581	7	3
Materials & Tools	18,398	20,805	(2,407)	(12)	4
Consulting & Professional Fees	10,856	9,491	1,365	14	5
Construction & Maintenance Services	13,026	12,456	570	5	6
Building & Property Services	20,730	21,044	(314)	(1)	
Equipment Maintenance & Rentals	12,470	11,332	1,138	10	7
Consumer Services	3,964	3,970	(6)	(0)	
Collection Costs	3,138	3,193	(55)	(2)	
Customer & Public Relations	3,769	3,915	(146)	(4)	
Sponsored Memberships	1,061	594	467	79	
Office & Administration	10,351	11,008	(657)	(6)	8
Computer Services	779	507	272	54	
Communication Systems	1,258	1,516	(258)	(17)	
Research & Development Costs	1,073	1,138	(65)	(6)	
Miscellaneous Expense	1,128	1,008	120	12	
Operating Expense Recovery	(12,572)	(11,980)	(592)	(5)	9
Less: Capital Order Activities	(221,914)	(195,051)	(26,863)	(14)	10
Less: Capitalized Overhead	(62,152)	(54,743)	(7,409)	(14)	11
Less: O&A Charged to Gas Operations	(50,744)	(48,976)	(1,768)	(4)	
Total Electric OM&A	**338,610**	**350,376**	**(11,766)**		

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
YEAR-OVER -YEAR CHANGE EXPLANATIONS

Ref	Cost Element	Change Inc/(dec)	Explanation
1	Overtime	7,992	Higher capital requirements in various projects to protect key in-service dates, greater storm restoration work and increased costs due to the impact of union contract settlements.
2	Employee Safety & Training	758	Higher costs associated with fire retardant clothing purchases.
3	Motor Vehicle	1,581	Higher external repair costs partly due to escalating replacement costs for vehicle parts and higher maintenance demands as a result of aging
4	Materials & Tools	(2,407)	Lower maintenance activities as a result of a greater focus on capital work at various generating and converter stations.
5	Consulting & Professional Fees	1,365	Higher costs associated with bio-physical environmental monitoring for the Wuskwatim Generating Station, gas related environmental activities as well as the Northern Construction Trades Training program.
6	Construction & Maintenance Services	570	Higher costs primarily due to meter exchange work contracted to Manitoba Hydro Utility Services (MHUS).
7	Equipment Maintenance & Rentals	1,138	Primarily due to IT system implementations and rising costs of software maintenance costs.
8	Office & Administration	(657)	Lower office supply purchases due to cost containment initiatives partly offset by higher postage costs.
9	Operating Expense Recovery	(592)	Primarily due to the recovery of additional costs incurred for the restoration work performed after the TCPL explosion and and higher recovery of costs from subsidiaries.
10	Capital Order Activities	(26,863)	Greater volume of capital work related to new transmission line construction, transmission line and substation infrastructure refurbishment, engineering and construction of northern generating stations as well as storm restoration.
11	Capitalized Overhead	(7,409)	Mainly due to higher capital activities.

Section:	Tab 5 Appendix 5.7	**Page No.:**	4 & 5
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please refile Schedule A & B of MH Exhibit #55 from the 2012 GRA, including 2009 to 2014 with a similar level of detail.

RATIONALE FOR QUESTION:

To understand the impact of accounting changes on revenue requirement.

RESPONSE:

Please see the following schedules which include the Accounting Policy and Estimate changes that have been implemented between 2009 to 2014 and have been accepted for rate setting purposes in Orders 5/12 and 43/13. Manitoba Hydro notes that the changes to overhead capitalized that were made between 2009 to 2014 are consistent with the recommendation made by the PUB in Order 116/08.

Also included on the following schedules are the Accounting Policy and Estimate changes that are forecast to be implemented from 2015 to 2024 as outlined in Appendix 5.7 of the Application.

SCHEDULE A - ACCOUNTING POLICY & ESTIMATE CHANGES - MH14

	Estimated Impact on Actual Results -->						Forecast -->									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Electric only (in millions of $'s)																
OM&A																
CGAAP Changes																
Intangible Assets	5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5
Overhead Capitalized	5	9	29	29	60	61	62	63	63	64	65	65	66	66	68	69
Pension & Other Benefits Changes (e.g. Discount Rate)	-	-	-	3	14	25	27	27	27	27	27	27	27	27	27	27
Subtotal CGAAP Changes	10	13	33	37	78	91	94	95	95	96	97	97	98	99	100	102
IFRS Changes																
Administrative Overhead								55	55	56	56	57	57	58	59	60
Meter Compliance, Exchange and Sampling								(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Pension								0	3	3	3	3	3	3	4	4
Employee Benefits								(3)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)
Subtotal IFRS Changes							-	51	56	57	58	58	59	60	61	62
Total OM&A Changes	**10**	**13**	**33**	**37**	**78**	**91**	**94**	**146**	**151**	**153**	**154**	**156**	**157**	**158**	**161**	**164**
DEPRECIATION EXPENSE																
CGAAP Changes																
Administrative Overhead					(0)	(1)	(1)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)
Subtotal CGAAP Changes	-	-	-	-	(0)	(1)	(1)	(2)	(3)	(3)	(4)	(4)	(5)	(6)	(6)	(7)
Depreciation Study Changes																
Average Service Life Changes (2010 Depreciation Study)	-	-	-	(35)	(36)	(41)	(46)	(49)	(51)	(51)	(57)	(64)	(73)	(70)	(72)	(71)
Average Service Life Changes (2014 Depreciation Study)	-	-	-	-	-	-	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)
Subtotal Depreciation Study Changes	-	-	-	(35)	(36)	(41)	(71)	(78)	(81)	(81)	(91)	(102)	(116)	(111)	(115)	(113)
IFRS Changes																
Administrative Overhead								(0)	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)
Meter Compliance, Exchange and Sampling								0	0	0	0	0	0	1	1	1
Provision for Asset Removal								(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)
Change to IFRS Compliant Depreciation								36	38	41	49	55	63	67	68	69
Subtotal IFRS Changes	-	-	-	-	-	-	-	(24)	(27)	(30)	(42)	(48)	(53)	(60)	(61)	(63)
Total Depreciation Changes	**-**	**-**	**-**	**(35)**	**(36)**	**(42)**	**(73)**	**(104)**	**(111)**	**(114)**	**(137)**	**(154)**	**(174)**	**(177)**	**(182)**	**(184)**
FINANCE EXPENSE																
Total Finance Expense Accounting Changes								(0)	(0)	(1)	(1)	(1)	(2)	(2)	(2)	(3)
CAPITAL TAX EXPENSE																
Total Capital Tax Expense Accounting Changes								(3)	(3)	(3)	(2)	(2)	(2)	(2)	(1)	(1)
Total Increase (Decrease) in Revenue Requirement	**10**	**13**	**33**	**1**	**43**	**49**	**21**	**39**	**37**	**35**	**14**	**(2)**	**(21)**	**(22)**	**(25)**	**(25)**

SCHEDULE B - ACCOUNTING POLICY & ESTIMATE CHANGES - IMPACT TO RETAINED EARNINGS & ACCUMULATED OTHER COMPREHENSIVE INCOME- MH14

Electric only (in millions of $'s)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
IMPACT TO RETAINED EARNINGS																	
Annual change to OM&A	(10)	(13)	(33)	(37)	(78)	(91)	(94)	(146)	(151)	(153)	(154)	(156)	(157)	(158)	(161)	(164)	(1 755)
Annual change to Depreciation & Amortization	-	-	-	35	36	42	73	104	111	114	137	154	174	177	182	184	1 521
Annual change to Finance & Capital Tax Changes	-	-	-	-	-	-	-	3	3	3	3	3	4	4	4	5	31
Write Offs to:																	
Administrative Overhead								(54)									(54)
Provision for Asset Removal								57									57
Change to Equal Life Group Depreciation								(33)									(33)
Pension & Employee Benefits								(45)									(45)
Total (Decrease) Increase to Retained Earnings	**(10)**	**(13)**	**(33)**	**(1)**	**(43)**	**(49)**	**(21)**	**(114)**	**(37)**	**(35)**	**(14)**	**2**	**21**	**22**	**25**	**25**	**(277)**
IMPACT TO AOCI																	
IFRS Changes																	
Pension Adjustment to AOCI								(424)	-	-	-	-	-	-	-	-	(424)
Pension Adjustment for discount rate changes								-	-	61	40	40	-	-	-	-	141
Total Annual Impact to AOCI	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(424)**	**-**	**61**	**40**	**40**	**-**	**-**	**-**	**-**	**(283)**

Section:	Tab 5 Appendix 5.7	Page No.:	4 & 5
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please refile Schedule 5.1.4 from the current application to include the years 2008/09 to 2012/13.

RATIONALE FOR QUESTION:

To understand the impact of accounting changes on revenue requirement.

RESPONSE:

The attached table provides the OM&A Costs by cost element and has been updated to include the years 2008/09 to 2012/13.

System changes have been implemented beginning in 2012/13 to align Manitoba Hydro's capitalization practices with industry standards and support Manitoba Hydro's transition to IFRS. As a result of these changes, the labour and benefits charged to capital is only available beginning in the 2012/13 fiscal year; information is not available for prior years.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(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	Average Annual % Inc/(Dec)
Wages & Salaries	$ 380,031	$ 407,988	$ 425,158	$ 451,926	$ 466,165	$ 480,511	$ 502,692	524,552	533,997	4.4%
Overtime	45,890	50,307	50,704	54,757	61,031	62,365	61,709	71,080	73,121	6.1%
Employee Benefits	83,495	83,013	95,376	104,674	130,886	157,094	160,592	155,892	158,992	8.8%
Sub-Total	509,417	541,307	571,238	611,357	658,082	699,970	724,993	751,523	766,109	
Less: Labour & Benefits Charged to Capital					(215,491)	(234,510)	(256,588)	(282,335)	(287,969)	7.6%
Labour & Benefits Charged to Operations*	509,417	541,307	571,238	611,357	442,591	465,460	468,405	469,188	478,140	-0.1%
Other Costs										
Employee Safety & Training	4,062	4,284	3,863	3,909	4,463	4,596	5,225	5,188	5,175	3.3%
Travel Expenses	31,671	32,435	32,594	31,266	31,194	31,915	31,766	31,628	31,634	0.0%
Motor Vehicle	24,125	24,281	24,436	28,676	29,516	29,670	29,682	29,699	29,699	2.8%
Materials & Tools	29,338	26,897	28,105	26,101	24,806	27,920	26,700	26,090	26,090	-1.3%
Consulting & Professional Fees	9,136	14,814	11,157	10,250	10,817	14,657	14,349	12,395	12,237	6.7%
Construction & Maintenance Services	18,000	20,109	22,657	20,750	16,259	16,775	19,364	18,580	18,580	1.1%
Building & Property Services	28,685	22,931	21,944	21,387	25,644	28,978	27,738	27,297	27,297	0.0%
Equipment Maintenance & Rentals	13,028	14,379	14,165	13,388	14,680	15,007	16,120	16,191	16,191	2.9%
Consumer Services	5,230	5,798	5,086	5,225	5,050	5,277	5,323	5,323	5,323	0.4%
Computer Services	858	983	1,003	861	849	678	985	1,020	1,019	3.7%
Collection Costs	5,019	4,599	4,497	4,035	4,261	3,125	4,078	4,078	4,078	-1.4%
Customer & Public Relations	6,355	8,155	7,905	8,093	6,731	5,610	5,334	5,344	5,316	-1.4%
Sponsored Memberships	1,464	1,325	1,917	1,608	1,767	1,249	1,764	1,737	1,737	4.9%
Office & Administration	14,538	15,320	14,316	14,277	13,874	14,724	15,722	15,721	15,717	1.1%
Communication Systems	1,449	1,772	1,678	1,683	1,817	1,963	1,928	1,928	1,928	3.9%
Research & Development Costs	3,059	3,952	3,651	2,797	3,372	2,195	2,747	2,747	2,747	1.1%
Miscellaneous Expense	6,548	1,190	1,264	2,032	2,040	1,485	954	900	900	-10.4%
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)	-2.5%
Strategic Initiative Funding							870	3,640	6,317	
Sub-Total	181,047	181,644	177,233	185,100	183,143	188,016	199,774	198,468	200,994	
Less: Other Costs Charged to Capital					(29,327)	(31,503)	(33,329)	(34,647)	(34,818)	4.4%
Other Costs Charged to Operations*	181,047	181,644	177,233	185,100	153,815	156,513	166,444	163,821	166,177	-0.8%
Total	**690,463**	**722,951**	**748,471**	**796,457**	**596,406**	**621,973**	**634,849**	**633,009**	**644,317**	-0.3%
Labour & Expense Capitalized	(205,175)	(224,298)	(243,545)	(268,651)						9.4%
Capitalized Overhead	(61,198)	(60,151)	(47,336)	(53,084)	(69,720)	(74,446)	(81,265)	(24,578)	(24,824)	-4.0%
Operating and Administration Charged to Centra	(59,803)	(60,951)	(60,644)	(62,687)	(63,735)	(66,810)	(67,829)	(66,691)	(67,818)	1.6%
Electric OM&A, including Accounting Changes	**364,287**	**377,551**	**396,946**	**412,035**	**462,952**	**480,717**	**485,755**	**541,740**	**551,675**	5.4%
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	**$ 354,632**	**$ 364,371**	**$ 364,057**	**$ 375,457**	**$ 384,607**	**$ 389,562**	**$ 391,897**	**$ 396,096**	**$ 400,330**	1.5%
Year over Year % Change, including Accounting Changes		3.6%	5.1%	3.8%	12.4%	3.8%	1.0%	11.5%	1.8%	5.4%
Year over Year % Change, excluding Accounting Changes		**2.7%**	**-0.1%**	**3.1%**	**2.4%**	**1.3%**	**0.6%**	**1.1%**	**1.1%**	**1.5%**

*Includes amounts capitalized through Overhead

Section:	Tab 5 Appendix 5.7	Page No.:	4 & 5
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please refile Figure 5.5.5 from the current application to include all years since 2008/09 and provide the Compound Annual Growth from 2008/09 to 2013/14 and 2013/14 through 2016/17.

RATIONALE FOR QUESTION:

To understand the impact of accounting changes on revenue requirement.

RESPONSE:

Please see the following summary of accounting and benefit changes for electric operations from 2008/09 through 2016/17, including Compound Annual Growth from 2008/09 to 2013/14 and 2013/14 to 2016/17.

SUMMARY OF ACCOUNTING & BENEFIT CHANGES - ELECTRIC OPERATIONS
(in thousands of dollars)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	IFF-14 2015/16 Forecast	2016/17 Forecast	Compound Annual Growth 2008/09-2013/14	Compound Annual Growth 2013/14-2016/17
Property Plant & Equipment											
CGAAP - Reduction to Costs Capitalized											
Stores Overhead	$ 5 000	$ 5 100	5 202	5 306	5 412	5 520	5 576	5 631	5 688		
Executive Costs		2 000	2 040	2 081	2 122	2 165	2 187	2 208	2 230		
Property Taxes on Facilities		2 000	2 040	2 081	2 122	2 165	2 187	2 208	2 230		
Interest on Common Assets (Facilities & Equipment)			11 165	11 388	11 616	11 848	11 967	12 087	12 207		
General & Administrative Departmental Costs			4 500	4 590	4 682	4 775	4 823	4 871	4 920		
Interest on Motor Vehicles			3 780	3 856	3 933	4 011	4 051	4 092	4 133		
IT Infrastructure & Related Support					20 022	20 422	20 626	20 833	21 041		
Building Depreciation & Operating Costs					10 271	10 476	10 581	10 687	10 793		
IFRS - Reduction to Costs Capitalized											
Technical & Softskills Training								15 980	16 140		
Service Areas (Management Accounting, HR, Safety, etc)								12 270	12 393		
Administrative & Clerical Support Staff								11 990	12 110		
Division & Department Manager								13 320	13 453		
Fleet & Stores Administration								1 140	1 151		
PP&E Reduction to Costs Capitalized	5 000	9 100	28 727	29 302	60 180	61 384	61 997	117 317	118 491	65.1	24.5
Intangible Assets											
CGAAP - Reduction to Costs Capitalized	4 655	4 080	4 162	4 245	4 330	4 416	4 505	4 550	4 595	(1.0)	1.3
Pension & Benefits											
CGAAP -Changes (e.g. Discount Rate)				3 032	13 835	25 355	27 356	27 356	27 356		
IFRS Changes								(2 700)	1 800		
		-	-	3 032	13 835	25 355	27 356	24 656	29 156	189.2	4.8
Other											
IFRS - Meter Sampling, Exchange and Testing								(879)	(897)		2.0
Total OM&A Impact	$ 9 655	$ 13 180	$ 32 889	$ 36 578	$ 78 345	$ 91 155	$ 93 858	$ 145 644	$ 151 345	56.7	18.4

Section:	Tab 5 Appendix 5.7	Page No.:	4 & 5
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate what administrative costs MH has incurred in each of the years since 2008/09 that used to be capitalized but that Manitoba Hydro proposes to start expensing in 2015/16.

RATIONALE FOR QUESTION:

To understand the impact of accounting changes on revenue requirement.

RESPONSE:

Manitoba Hydro will start expensing the following administrative costs beginning in 2015/16:

- Technical & Softskills Training
- Service Areas (Management Accounting, HR, Safety, etc)
- Administrative & Clerical Support Staff
- Division & Department Manager
- Fleet & Stores Administration

For additional information on these cost categories please see the response to PUB/MH-I-74b.

Section:	Tab 5, [Appendix 5.4 p. 6]	Page No.:	15
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expense		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

At the last GRA MH provided an estimate for the impact of IFRS on operating costs. Included was the impact of removing administrative overhead costs MH stated:

> *MH will discontinue the capitalization of an additional $38 million of general overhead costs annually upon transition to IFRS in 2014/15. The $38 million is comprised primarily of expenditures for training, services and administration, and managerial related charges.*

This year MH states the amount is now $58 million as per the following table:

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:

Please explain why administrative overhead costs have grown to $58 million in 2015/16 from $38 million for 2013/14.

RATIONALE FOR QUESTION:

Increases in OM&A related to accounting changes impact revenue requirement.

RESPONSE:

The increase in overhead costs no longer eligible for capitalization is primarily a result of higher levels of construction activity, resulting in a proportionate allocation of overhead to capital. Historically, approximately 40% of Manitoba Hydro's activities were directed towards the construction of capital assets; however, as Manitoba Hydro is entering a period of extensive capital investment this figure has grown to approximately 45%.

Section:	Tab 5, [Appendix 5.4 p. 6]	Page No.:	15
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expense		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

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Division and Department Manager	14	7	7	100%
Fleet & Stores Administration	1	2	-1	-50%
Total	58	38	20	53%

QUESTION:

Provide an account level analysis for the difference, comparing the accounts that were included in the 2015/16 forecast and 2013/14 estimate and explain the difference.

RATIONALE FOR QUESTION:

Increases in OM&A related to accounting changes impact revenue requirement.

RESPONSE:

The increase in overhead costs for each category is primarily a result of higher levels of construction activity, resulting in a proportionate allocation of overhead to capital. A description of the activities included in each category is provided below.

Technical & softskills training – technical training includes employee time and related expenses on training for operational skills, trades and apprenticeship programs. Technical and trades training programs develop specific trade skills required to perform maintenance and capital related activities in a safe and reliable manner. The costs associated with such programs include salaries and benefits, course fees, travel, and tools. Training is not considered eligible for capitalization under IFRS as entities are not able to control the benefits associated with such training and such expenditures do not meet the criteria for recognition as an asset. In other words, entities cannot prevent employees from receiving training and then assuming employment with another employer.

Softskill training includes training programs administered by Employee Learning & Development as well as external courses. Such training focuses on supervisory and management skills. Consistent with the analysis related to technical trades training, such costs are not deemed eligible for capitalization as the Corporation cannot control the benefits associated with such costs.

Service areas - include department and staff costs associated with Management Accounting (including financial reporting, budgeting support, financial planning and customer accounting), Human Resources, Corporate Safety and other service departments. These departments perform roles that support many of the organization's capital activities such as:

- Project and CEF budget finalization, including various analytics
- Capital performance reporting
- Employee compensation, labor relations, and payroll administration
- Development of Corporate safety manuals, guidelines and training

This work however, is considered several levels removed from the direct construction activities of specific capital assets and is therefore not considered directly attributable.

Where time is spent in support of a specific capital project, staff in these departments will be required to time card directly to a capital project.

Administrative and clerical support staff - includes employees within a department whose role is to support the staff that are directly "hands to tools" with respect to the maintenance, operations and construction of assets. Examples of duties performed by support staff include time entry, expense processing, human resource management and business planning, as well as other tasks of a general or administrative nature. Other administrative costs would include items such as office expenses (e.g. postage and general office supplies), customer and public relations costs (e.g donations and grants) and advertising. Generally, such costs are not eligible for capitalization as they are too far removed from the development of a specific capital asset. There are, however, instances where support staff costs may be directly attributable to the construction project of a specific asset and are thus, eligible for capitalization in the costs of that project.

Division and department managers - key members of a Business Unit's senior management team provide management of the strategic, financial, capital and human resource assets of the Division. Although they are active in the decision making process and have overall responsibility for the outputs of their divisions and departments, management is not typically involved in the direct management of any given capital project. Thus, such costs are generally not eligible for capitalization. There are instances, however, where senior management directs their activities to specific capital projects for an extended period of time. In such instances, their time would be considered eligible for capitalization in the costs of the specific asset.

Fleet & stores - includes the activities related to the acquisition, maintenance and management of MH's fleet of vehicles and the receiving, storing and issuing of materials and transporting materials to the jobsite. MH's fleet of motor vehicles ranges from cars and vans to bucket trucks and heavy tractor equipment. Fleet vehicles are used in the maintenance, operations, and construction activities of the Corporation. Costs associated with fleet activities include maintenance, fuel, depreciation, and insurance. To the extent that vehicles are used directly for a capital project, such costs are eligible for capitalization. Costs pertaining to fleet vehicles used for maintenance or operational activities are not eligible for capitalization. Fleet management, support and administration costs, including the accounting and IT system that captures all costs for each respective vehicle, are not eligible for capitalization as they are too far removed from the construction of a specific asset.

Approximately 90% of stores issues are for capital projects and thus, many of the activities associated with the stores functions are eligible for capitalization. Similar to Fleet, Stores management and administrative costs are not eligible for capitalization as they are too far removed from the construction of a specific asset.

Section:	Tab 5: Section 3: Appendix 3.2	**Page No.:**	Section 5 P. 23 Appendix 3.2 pg 4.
Topic:	Finance Expense		
Subtopic:	Interest Rate Forecast		
Issue:	Weighted Average Interest Rate		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide an updated table indicating the detail of the interest rate forecast for each year in the 20 year forecast. Please also include the assumed weighted average interest rate.

RATIONALE FOR QUESTION:

RESPONSE:

Please see the response to PUB/MH-I-75c for the table indicating the detail of the interest rate forecast for each year in the 20 year forecast.

Please see the response to PUB/MH-I-10a for the weighted average interest rate chart (as previously shown as Chart 5 in Appendix 3.7) extended to 2033/34 for both IFF14 and the IFF14 scenario updated for interest rates as filed in response to PUB/MH-I-10b.

Section:	Tab 5: Section 3: Appendix 3.2	Page No.:	Section 5 P. 23 Appendix 3.2 pg 4.
Topic:	Finance Expense		
Subtopic:	Interest Rate Forecast		
Issue:	Weighted Average Interest Rate		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain how changing interest rates will have a counterbalancing impact on the interest capitalization rate.

RATIONALE FOR QUESTION:

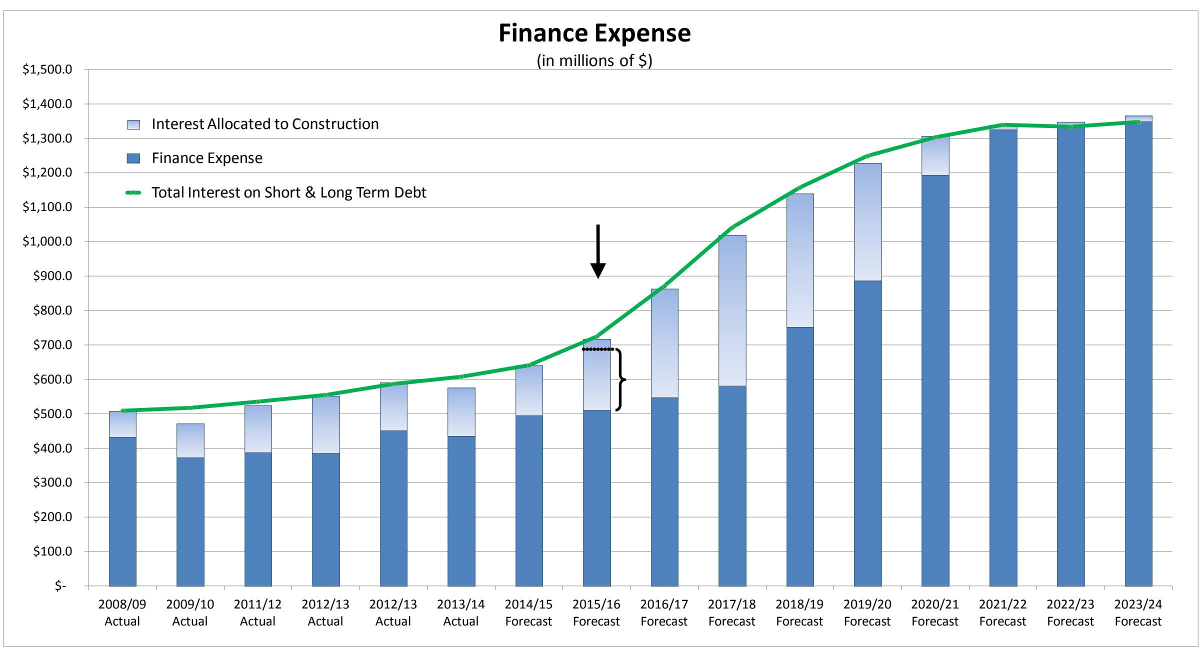
RESPONSE:

Manitoba Hydro operates in a complex economic environment that simultaneously affects many parts of its operations. The economy's impact on Manitoba Hydro's revenue requirement is not exclusively seen through changing interest rates and the evolving views of Manitoba Hydro's external interest rate forecasters. There are numerous counterbalances.

For example, the low interest rate environment has provided an opportunity for Manitoba Hydro, on behalf its ratepayers, to beneficially reduce its weighted average interest rate on its debt portfolio (please see PUB/MH-I-10a); however, poor economic conditions have also contributed to low energy prices which have been adverse to Manitoba Hydro's financial performance (please see PUB/MH-I-14a for a graphical depiction of Manitoba Hydro's changing actual and forecast average unit export revenues). These counterbalancing relationships are two sides of the same economic coin.

Counterbalancing relationships also exist within finance expense. For example, as described in Tab 5 Section 5.6, interest allocated to construction is the interest capitalized during the construction of a project, which is a reduction to finance expense and a charge to the capital project. The Corporation's net interest expense is the total interest on short and long term debt minus the interest allocated to construction. In circumstances where interest rates become lower, gross interest expense would be expected to decrease; however there would also be a reduction in the capitalized interest rate – thereby reducing the credited amount of interest allocated to construction (which in turn also reduces the cost of capital projects) and counterbalancing some of the beneficial impact of lower interest rates when deriving net finance expense.

As shown in the following chart from the Application (Figure 5.8), the interest allocated to construction (lightly shaded blue bars) is the primary factor that reduces the level of total interest on short and long term debt (green line) to arrive at net finance expense (dark blue bars) on the financial statements. The graphics shown on the chart for the 2015/16 year, conceptually illustrate how lower interest rates would act to reduce the total interest on short and long term debt (down arrow on the green line), while also shrinking the interest allocated to construction, thereby providing some counterbalance to changing interest rates within net finance expense (dark blue bars).



Section:	Tab 5: Section 3: Appendix 3.2	**Page No.:**	Section 5 P. 23 Appendix 3.2 pg 4.
Topic:	Finance Expense		
Subtopic:	Interest Rate Forecast		
Issue:	Weighted Average Interest Rate		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file an update to the short term and long term interest rate forecast based on January bank forecasts and provide a comparison between the current forecast interest rates and that included in the application.

RATIONALE FOR QUESTION:

RESPONSE:

Table 1 on the following page summarizes the forecast of Manitoba Hydro Canadian short-term interest rates for the 2014/15 – 2033/34 period based on an update of end of January 2015 source forecasts, and provides a comparison to those rates included in the Application. The source forecasts are also provided with this response.

Table 1: Manitoba Hydro Canadian Short-term Rate - %

	January 2015 Update			IFF 2014 – (Fall 2014 Update)		
	Canada 3-Month T-Bill	Guarantee Fee	MH Cdn Short Term Rate	Canada 3-Month T-Bill	Guarantee Fee	MH Cdn Short Term Rate
2014/15	0.85%	1.00%	1.85%	0.95%	1.00%	1.95%
2015/16	0.50%	1.00%	1.50%	1.30%	1.00%	2.30%
2016/17	0.95%	1.00%	1.95%	2.40%	1.00%	3.40%
2017/18	2.30%	1.00%	3.30%	3.10%	1.00%	4.10%
2018/19	2.95%	1.00%	3.95%	3.45%	1.00%	4.45%
2019/20	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2020/21	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2021/22	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2022/23	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2023/24	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2024/25	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2025/26	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2026/27	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2027/28	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2028/29	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2029/30	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2030/31	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2031/32	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2032/33	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%
2033/34	3.50%	1.00%	4.50%	3.90%	1.00%	4.90%

Table 2 on the following page summarizes the forecast of Manitoba Hydro Canadian long-term interest rates for the 2014/15 – 2033/34 period based on an update of end of January 2015 source forecasts, and provides a comparison to those rates included in the application.

Table 2: Manitoba Hydro Canadian Long-term Rate - %

	January 2015 Update				**IFF 2014 – (Fall 2014 Update)**			
	Canada 10 Yr+ Bond Yield	Spread	Guarantee Fee	MH Cdn Long Term Rate	Canada 10 Yr+ Bond Yield	Spread	Guarantee Fee	MH Cdn Long Term Rate
2014/15	2.30%	0.90%	1.00%	4.20%	2.60%	0.90%	1.00%	4.50%
2015/16	2.15%	0.85%	1.00%	4.00%	3.30%	0.80%	1.00%	5.10%
2016/17	2.80%	0.75%	1.00%	4.55%	3.75%	0.75%	1.00%	5.50%
2017/18	3.90%	0.75%	1.00%	5.70%	4.05%	0.75%	1.00%	5.80%
2018/19	3.95%	0.75%	1.00%	5.75%	4.25%	0.75%	1.00%	6.00%
2019/20	3.95%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2020/21	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2021/22	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2022/23	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2023/24	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2024/25	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2025/26	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2026/27	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2027/28	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2028/29	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2029/30	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2030/31	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2031/32	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2032/33	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%
2033/34	4.00%	0.75%	1.00%	5.75%	4.45%	0.75%	1.00%	6.20%

Note 1: Values in the above table may not add up due to rounding.

As compared to the Canadian interest rate forecasts used in the application which reflected the consensus outlook as of September 2014, forecasts for Manitoba Hydro's short-term and long-term interest rates are projected to be lower for every year of the January updated forecast. The January updated forecast includes sources that had prepared a forecast post the January 21, 2015 announcement from the Bank of Canada to drop the overnight rate from 1.0% to 0.75%.

Canadian Economic Outlook

BMO Capital Markets Economics

January 23, 2015

				2014				2015				2016	2013	2014	2015	2016
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4				
PRODUCTION	**(quarter/quarter % change : a.r.)**															
Real GDP (chain-weighted)	1.0	3.6	2.8	2.0	1.5	1.8	2.0	2.2	2.3	2.3	2.0	2.1	2.0	2.4	2.1	2.2
Final Sales	2.0	5.8	3.6	0.7	1.3	1.7	2.2	2.3	2.3	2.4	2.0	2.1	1.8	2.8	2.0	2.2
Final Domestic Demand	0.1	3.3	2.8	2.0	-0.2	0.3	1.3	1.6	1.9	2.1	2.0	2.1	1.5	1.6	1.2	1.7
Consumer Spending	1.5	4.4	2.8	2.7	2.7	2.5	2.3	2.3	2.2	2.1	1.9	2.0	2.5	2.8	2.7	2.2
Durables	1.6	14.9	12.6	3.0	2.0	1.0	1.5	2.0	2.0	1.5	1.7	1.5	3.8	5.7	4.0	1.7
Non-Durables	4.0	-0.5	-0.7	2.5	2.8	2.7	2.5	2.3	2.3	2.2	1.9	2.0	2.3	2.7	2.0	2.3
Services	1.3	3.5	2.1	2.6	2.7	2.7	2.3	2.4	2.2	2.1	2.0	2.1	2.3	2.1	2.6	2.2
Government Spending	-0.7	1.4	0.3	1.0	0.0	0.2	0.7	1.1	1.1	1.5	1.3	1.5	0.1	-0.1	0.5	1.1
Business Investment	-1.9	0.8	0.5	1.7	-14.3	-10.7	-1.3	0.4	3.2	5.3	5.7	6.2	2.6	-0.4	-5.5	2.0
Non-Residential Construction	-0.3	0.5	-1.9	1.0	-15.0	-11.0	-1.8	0.0	3.0	5.5	6.0	6.5	5.0	-0.1	-6.3	1.9
Machinery and Equipment	-5.0	1.4	5.2	3.0	-13.0	-10.0	-0.5	1.0	3.5	5.0	5.0	5.5	-1.7	-1.1	-4.1	2.2
Residential Construction	-4.2	11.4	12.5	0.0	1.0	1.0	0.5	0.0	0.0	-0.5	-1.0	-1.0	-0.4	2.5	2.7	-0.2
Exports	0.9	19.0	6.9	-4.0	4.8	5.4	5.0	5.3	5.1	4.6	4.4	4.1	2.0	5.1	4.3	4.9
Imports	-4.8	9.8	4.0	0.0	0.1	0.9	1.9	3.1	3.5	3.6	4.1	3.9	1.3	1.5	1.7	3.2
	(billions of chained 2007 dollars : a.r.)															
Inventory Change	13.3	4.8	0.6	6.4	7.5	8.2	7.3	7.0	6.7	6.4	6.4	6.5	12.4	6.3	7.5	6.5
Contribution to GDP Growth	-0.9	-2.0	-1.0	1.3	0.2	0.1	-0.2	-0.1	-0.1	-0.1	0.0	0.0	0.2	-0.4	0.1	-0.1
Net Exports	-29.6	-19.3	-15.6	-21.4	-15.0	-8.9	-4.6	-1.6	0.6	2.0	2.5	2.8	-39.6	-21.5	-7.5	2.0
Contribution to GDP Growth	1.8	2.8	0.9	-1.3	1.5	1.3	0.9	0.6	0.4	0.2	0.0	0.0	0.2	1.1	0.8	0.5
	(billions of dollars : a.r.)															
Nominal GDP	1,950	1,969	1,992	1,991	1,974	1,982	2,004	2,026	2,050	2,075	2,101	2,129	1,894	1,976	1,997	2,089
(% chng : a.r.)	6.7	3.9	4.7	-0.1	-3.3	1.5	4.4	4.6	4.8	5.0	5.1	5.3	3.4	4.3	1.1	4.6
INFLATION	**(quarter/quarter % change : a.r.)**															
GDP Price Index	5.5	0.4	1.8	-2.0	-4.8	-0.3	2.4	2.4	2.5	2.6	3.0	3.1	1.4	1.9	-1.0	2.4
CPI All Items	2.8	3.7	1.3	0.1	-1.5	1.8	2.2	2.3	2.1	1.9	2.2	2.4	0.9	1.9	0.8	2.1
Excl. Food & Energy	2.4	2.3	2.1	1.2	1.5	1.8	2.1	2.0	2.0	1.6	2.0	2.4	0.9	1.6	1.8	1.9
Food Prices	2.2	5.5	1.5	3.9	2.8	1.6	2.2	2.6	1.7	2.1	1.9	2.1	1.2	2.3	2.7	2.1
Energy Prices	11.2	11.2	-5.8	-17.5	-32.1	1.9	3.0	4.4	4.4	5.0	5.2	3.4	1.5	3.5	-11.7	4.2
Services	1.6	3.6	3.3	0.2	0.9	2.1	2.0	2.1	2.1	2.3	2.0	2.2	1.4	2.1	1.7	2.1
	(year/year % change)															
CPI All Items	1.4	2.2	2.1	1.9	0.9	0.4	0.6	1.2	2.1	2.1	2.1	2.2				
BoC Core	1.3	1.7	2.0	2.2	2.1	1.9	1.9	2.1	2.1	2.0	2.0	2.0	1.2	1.8	2.0	2.0
FINANCIAL	**(average for the quarter : %)**															
Overnight Rate	1.00	1.00	1.00	1.00	0.67	0.50	0.50	0.50	0.75	1.00	1.25	1.50	1.00	1.00	0.55	1.15
3-Month T-Bill	0.87	0.93	0.94	0.90	0.60	0.41	0.41	0.41	0.67	0.92	1.18	1.44	0.97	0.91	0.46	1.05
90-Day BAs	1.26	1.27	1.28	1.28	0.97	0.77	0.77	0.77	1.02	1.26	1.51	1.76	1.20	1.27	0.82	1.39
10 Year Bond Yield	2.47	2.35	2.14	1.95	1.53	1.66	1.84	2.03	2.18	2.29	2.40	2.51	2.26	2.23	1.76	2.34
Canada/US spread: (bps)																
90 day	82	90	91	87	57	30	7	-17	-14	-12	-9	-30	91	88	19	-16
10 year	-30	-27	-36	-33	-36	-38	-40	-41	-41	-42	-43	-45	-9	-31	-39	-43
FOREIGN TRADE	**(billions of dollars : a.r.)**															
Current Account Balance	-45.0	-39.6	-33.6	-52.7	-74.6	-76.4	-67.3	-61.7	-57.1	-53.2	-48.9	-44.9	-56.3	-42.7	-70.0	-51.0
(% of GDP)	-2.3	-2.0	-1.7	-2.6	-3.8	-3.9	-3.4	-3.0	-2.8	-2.6	-2.3	-2.1	-3.0	-2.2	-3.5	-2.4
Merchandise Balance	6.3	9.3	11.6	-10.2	-35.0	-39.1	-31.0	-26.7	-23.2	-20.3	-16.8	-13.7	-7.2	4.2	-33.0	-18.5
Non-Merchandise Balance	-51.4	-48.9	-45.2	-42.4	-39.6	-37.3	-36.3	-35.0	-33.8	-32.9	-32.1	-31.2	-49.0	-47.0	-37.1	-32.5
	(average for the quarter)															
Exchange Rate (US¢/C$)	90.6	91.7	91.8	88.1	81.6	78.9	78.7	79.5	80.5	81.4	82.2	83.0	97.1	90.6	79.7	81.8
Exchange Rate (C$/US$)	1.103	1.090	1.089	1.135	1.226	1.267	1.271	1.257	1.242	1.229	1.217	1.204	1.030	1.105	1.255	1.223
Exchange Rate (¥/C$)	93.1	93.6	95.5	100.8	98.1	96.0	96.8	99.1	101.3	103.4	105.5	107.6	94.7	95.8	97.5	104.5
Exchange Rate (C$/Euro)	1.51	1.50	1.44	1.42	1.39	1.45	1.45	1.42	1.40	1.37	1.35	1.33	1.37	1.47	1.43	1.36
INCOMES	**(year/year % change)**															
Corporate Profits Before Tax	11.0	19.4	10.4	0.3	-19.9	-23.6	-23.5	-16.0	1.6	7.7	9.4	11.1	0.7	10.0	-20.8	7.4
Corporate Profits After Tax	3.0	9.5	7.8	-0.1	-11.3	-15.5	-16.9	-10.6	1.1	4.2	5.2	6.2	7.3	5.0	-13.6	4.2
Personal Income	3.3	3.6	3.8	3.1	1.8	1.6	2.2	3.0	4.5	5.1	4.7	4.8	3.7	3.4	2.2	4.8
Real Disposable Income	1.8	1.5	2.0	1.3	0.3	0.7	1.1	1.5	2.5	3.0	2.4	2.3	2.5	1.6	0.9	2.6
	(average for the quarter : %)															
Savings Rate	5.0	3.9	3.9	3.5	2.4	2.0	2.5	2.5	2.6	2.7	2.8	2.8	5.2	4.1	2.4	2.7
OTHER INDICATORS	**(quarter average)**															
Unemployment Rate (%)	7.0	7.0	6.9	6.6	6.7	6.7	6.6	6.6	6.5	6.4	6.3	6.3	7.1	6.9	6.6	6.4
Housing Starts (000s, a.r.)	176	196	199	185	184	177	178	183	178	179	181	183	188	189	180	180
Existing Home Sales (y/y % ch)	1.9	6.3	6.0	6.2	0.5	-5.3	-4.6	-4.2	2.8	1.5	-2.6	-1.5	0.7	5.1	-3.5	0.0
MLS Home Price Index (y/y % ch)	5.0	5.1	5.3	5.4	3.4	1.9	2.1	0.7	0.9	0.4	-0.6	-0.6	2.7	5.2	2.0	0.0
Motor Vehicle Sales (mlns, a.r.)	1.74	1.85	1.99	1.96	1.93	1.89	1.88	1.87	1.85	1.86	1.85	1.84	1.77	1.89	1.89	1.85
	(quarter/quarter % change : a.r.)															
Employment Growth	0.4	0.3	1.4	1.8	0.1	0.6	0.9	1.0	1.4	1.0	1.0	0.9	1.3	0.8	0.8	1.1
Industrial Production	4.7	4.0	1.2	4.1	-2.9	-0.6	1.3	1.3	3.2	3.8	3.3	3.0	1.8	3.6	0.5	2.5
Federal Budget Balance (% of FY GDP)													-0.3	-0.1	0.3	0.4

Note: Outlined areas represent forecast periods

CIBC WORLD MARKETS INC.

January 29, 2015

INTEREST & FOREIGN EXCHANGE RATES

		2015					2016			
END OF PERIOD:		**27-Jan**	**Mar**	**Jun**	**Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
CDA	Overnight target rate	0.75	0.50	0.50	0.50	0.50	0.50	0.75	1.00	1.00
	98-Day Treasury Bills	0.58	0.45	0.45	0.45	0.50	0.60	0.80	0.95	1.00
	2-Year Gov't Bond	0.44	0.40	0.45	0.50	0.60	0.70	0.85	1.10	1.20
	10-Year Gov't Bond	1.35	1.40	1.70	2.00	2.00	2.10	2.40	2.60	2.65
	30-Year Gov't Bond	1.93	2.00	2.35	2.55	2.70	2.90	2.95	3.00	3.05
U.S.	Federal Funds Rate	0.10	0.10	0.25	0.75	1.25	1.25	1.25	1.25	1.50
	91-Day Treasury Bills	0.02	0.05	0.30	0.85	1.10	1.35	1.25	1.20	1.40
	2-Year Gov't Note	0.50	0.75	1.20	1.50	1.70	1.65	1.65	1.70	1.90
	10-Year Gov't Note	1.77	2.10	2.65	3.00	2.90	2.80	3.05	3.25	3.35
	30-Year Gov't Bond	2.34	2.50	2.90	3.20	3.30	3.30	3.55	3.65	3.70
Canada - US T-Bill Spread		0.57	0.40	0.15	-0.40	-0.60	-0.75	-0.45	-0.25	-0.40
Canada - US 10-Year Bond Spread		-0.41	-0.70	-0.95	-1.00	-0.90	-0.70	-0.65	-0.65	-0.70
Canada Yield Curve (30-Year — 2-Year)		1.49	1.60	1.90	2.05	2.10	2.20	2.10	1.90	1.85
US Yield Curve (30-Year — 2-Year)		1.85	1.75	1.70	1.70	1.60	1.65	1.90	1.95	1.80
EXCHANGE RATES	CADUSD	0.81	0.79	0.77	0.77	0.78	0.80	0.81	0.82	0.81
	USDCAD	1.24	1.26	1.30	1.30	1.28	1.25	1.23	1.22	1.24
	USDJPY	118	119	122	125	122	117	116	115	114
	EURUSD	1.14	1.12	1.09	1.07	1.10	1.13	1.16	1.20	1.23
	GBPUSD	1.52	1.50	1.45	1.45	1.49	1.51	1.53	1.56	1.58
	AUDUSD	0.79	0.77	0.76	0.74	0.76	0.79	0.81	0.83	0.85
	USDCHF	0.90	0.88	0.89	0.90	0.89	0.88	0.86	0.83	0.83
	USDBRL	2.57	2.75	2.80	2.83	2.97	3.02	3.05	3.05	3.04
	USDMXN	14.57	14.15	13.85	13.58	13.55	13.62	13.63	13.90	13.86

Table 4
United States: fixed income market

End of period in %	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1f	2015 Q2f	2015 Q3f	2015 Q4f	2016 Q1f	2016 Q2f	2016 Q3f	2016 Q4f
Key rate												
Federal funds	0.25	0.25	0.25	0.25	0.25	0.25	0.50	1.00	1.00	1.00	1.25	1.75
Treasury bills												
3-month	0.05	0.04	0.02	0.04	0.05	0.10	0.55	0.85	0.90	1.00	1.30	1.60
Federal bonds												
2-year	0.39	0.42	0.56	0.63	0.65	0.80	1.10	1.30	1.40	1.55	1.70	1.80
5-year	1.71	1.60	1.77	1.64	1.50	1.65	1.90	2.00	2.05	2.15	2.30	2.40
10-year	2.73	2.52	2.51	2.17	2.00	2.15	2.35	2.50	2.55	2.65	2.80	3.00
30-year	3.56	3.34	3.21	2.75	2.60	2.75	2.90	3.00	3.05	3.10	3.20	3.35
Yield curve												
5-year - 3-month	1.66	1.56	1.75	1.60	1.45	1.55	1.35	1.15	1.15	1.15	1.00	0.80
10-year - 2-year	2.34	2.09	1.95	1.54	1.35	1.35	1.25	1.20	1.15	1.10	1.10	1.20
30-year - 3-month	3.51	3.30	3.19	2.71	2.55	2.65	2.35	2.15	2.15	2.10	1.90	1.75

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

Table 5
Canada: fixed income market

End of period in %	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1f	2015 Q2f	2015 Q3f	2015 Q4f	2016 Q1f	2016 Q2f	2016 Q3f	2016 Q4f
Key rate												
Federal funds	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	0.50	1.00	1.00	1.25
Treasury bills												
3-month	0.89	0.94	0.92	0.92	0.40	0.40	0.40	0.40	0.60	1.00	1.10	1.40
Federal bonds												
2-year	1.07	1.10	1.12	1.01	0.45	0.60	0.70	0.80	0.90	1.25	1.40	1.55
5-year	1.71	1.53	1.63	1.34	0.75	0.95	1.25	1.40	1.55	1.70	1.80	1.90
10-year	2.46	2.24	2.15	1.79	1.30	1.45	1.70	1.90	2.00	2.20	2.30	2.40
30-year	2.96	2.78	2.67	2.34	2.00	2.15	2.30	2.40	2.50	2.60	2.65	2.80
Yield curve												
5-year - 3-month	0.82	0.59	0.71	0.42	0.35	0.55	0.85	1.00	0.95	0.70	0.70	0.50
10-year - 2-year	1.39	1.14	1.03	0.78	0.85	0.85	1.00	1.10	1.10	0.95	0.90	0.85
30-year - 3-month	2.07	1.84	1.75	1.42	1.60	1.75	1.90	2.00	1.90	1.60	1.55	1.40
Spreads (Canada - U.S.)												
3-month	0.84	0.90	0.90	0.88	0.35	0.30	-0.15	-0.45	-0.30	0.00	-0.20	-0.20
2-year	0.68	0.68	0.56	0.38	-0.20	-0.20	-0.40	-0.50	-0.50	-0.30	-0.30	-0.25
5-year	-0.00	-0.07	-0.14	-0.30	-0.75	-0.70	-0.65	-0.60	-0.50	-0.45	-0.50	-0.50
10-year	-0.27	-0.28	-0.36	-0.38	-0.70	-0.70	-0.65	-0.60	-0.55	-0.45	-0.50	-0.60
30-year	-0.60	-0.56	-0.54	-0.41	-0.60	-0.60	-0.60	-0.60	-0.55	-0.50	-0.55	-0.55

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

IHS Global Insight - February 10, 2015

Table 1

Selected Economic Indicators

	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4	19Q1
3-Month T-Bill Rate (%)	0.88	0.93	0.93	0.90	0.51	0.48	0.48	0.46	0.44	0.44	0.79	1.31	1.96	2.53	3.06	3.49	3.50	3.50	3.50	3.50	3.50
US 3-Month T-Bill Rate (%)	0.05	0.03	0.03	0.02	0.05	0.24	0.50	0.74	1.00	1.33	1.76	2.23	2.69	3.14	3.47	3.51	3.51	3.51	3.51	3.51	3.51
Canada-US Differential (% pts.)	0.83	0.89	0.91	0.87	0.46	0.24	-0.03	-0.28	-0.55	-0.89	-0.97	-0.91	-0.72	-0.61	-0.41	-0.02	-0.01	-0.01	-0.01	-0.01	-0.01
Prime Rate (%)	3.00	3.00	3.00	3.00	2.77	2.60	2.60	2.60	2.60	2.60	2.93	3.43	4.10	4.68	5.18	5.60	5.60	5.60	5.60	5.60	5.60
Overnight Rate (%)	1.00	1.00	1.00	1.00	0.67	0.50	0.50	0.50	0.50	0.50	0.83	1.33	2.00	2.58	3.08	3.50	3.50	3.50	3.50	3.50	3.50
Bank Rate (%)	1.25	1.25	1.25	1.25	0.92	0.75	0.75	0.75	0.75	0.75	1.08	1.58	2.25	2.83	3.33	3.75	3.75	3.75	3.75	3.75	3.75
GOC Bond Rate (1-3 yrs.) (%)	1.02	1.06	1.10	1.02	0.59	0.59	0.61	0.62	0.64	0.68	1.02	1.50	2.10	2.62	3.10	3.50	3.51	3.51	3.51	3.51	3.51
GOC Bond Rate (3-5 yrs.) (%)	1.38	1.41	1.43	1.32	0.83	0.91	1.00	1.09	1.20	1.33	1.64	2.03	2.49	2.87	3.23	3.52	3.52	3.52	3.52	3.52	3.52
GOC Ten-Year Bond Rate (%)	2.42	2.29	2.12	1.92	1.40	1.70	1.95	2.22	2.56	2.94	3.17	3.33	3.43	3.49	3.54	3.56	3.56	3.56	3.56	3.56	3.56
US Ten-Year T-Note Rate (%)	2.76	2.62	2.50	2.28	1.84	2.13	2.39	2.65	3.00	3.37	3.60	3.77	3.86	3.92	3.98	3.99	3.99	3.99	3.99	3.99	3.99
ExCh. Rate (US-Can.)	90.6	91.7	91.8	88.1	79.0	74.8	77.3	79.0	80.0	80.5	82.3	84.5	85.8	87.0	87.8	88.6	89.4	89.6	89.9	90.0	90.0

	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4	22Q1	22Q2	22Q3	22Q4	23Q1	23Q2	23Q3	23Q4	24Q1	24Q2	24Q3	24Q4
3-Month T-Bill Rate (%)	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
US 3-Month T-Bill Rate (%)	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
Canada-US Differential (% pts.)	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Prime Rate (%)	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60	5.60
Overnight Rate (%)	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
Bank Rate (%)	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75	3.75
GOC Bond Rate (1-3 yrs.) (%)	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
GOC Bond Rate (3-5 yrs.) (%)	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52
GOC Ten-Year Bond Rate (%)	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56
US Ten-Year T-Note Rate (%)	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99
ExCh. Rate (US-Can.)	90.3	91.1	91.4	91.8	91.8	91.8	91.8	91.9	91.9	91.8	91.8	91.7	91.4	91.4	91.4	91.4	91.3	91.2	91.0	91.0	90.8	90.8	90.8

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Table 24
Interest Rates
(Percent)

	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4	19Q1	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4	22Q1	22Q2	22Q3	22Q4	23Q1	23Q2	23Q3	23Q4	24Q1	24Q2	24Q3	24Q4
Government of Canada																																												
Treasury Bills																																												
3 Months	0.88	0.93	0.93	0.90	0.51	0.48	0.48	0.46	0.44	0.44	0.79	1.31	1.96	2.53	3.06	3.49	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
6 Months	0.91	0.95	0.96	0.92	0.53	0.50	0.50	0.49	0.47	0.47	0.82	1.34	1.99	2.56	3.08	3.52	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
Bonds																																												
1-3 Years	1.02	1.06	1.10	1.02	0.59	0.59	0.61	0.62	0.64	0.68	1.02	1.50	2.10	2.62	3.10	3.50	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
3-5 Years	1.38	1.41	1.43	1.32	0.83	0.91	1.00	1.09	1.20	1.33	1.64	2.03	2.49	2.87	3.23	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52
5 Years	1.63	1.58	1.57	1.45	0.94	1.07	1.19	1.31	1.47	1.65	1.94	2.29	2.67	2.99	3.29	3.52	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53	3.53
5-10 Years	1.97	1.91	1.87	1.70	1.18	1.40	1.59	1.78	2.04	2.32	2.58	2.83	3.07	3.25	3.42	3.54	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55
10 Years	2.42	2.29	2.12	1.92	1.40	1.70	1.95	2.22	2.56	2.94	3.17	3.33	3.43	3.49	3.54	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56
10+ Years	2.81	2.69	2.55	2.35	2.35	2.69	2.98	3.29	3.67	4.07	4.33	4.52	4.64	4.71	4.79	4.82	4.83	4.85	4.86	4.87	4.88	4.89	4.90	4.90	4.91	4.91	4.92	4.92	4.93	4.93	4.93	4.94	4.94	4.94	4.94	4.95	4.95	4.95	4.95	4.95	4.95	4.96	4.96	4.96
30 Years	2.95	2.84	2.67	2.47	1.98	2.30	2.58	2.87	3.24	3.63	3.87	4.05	4.17	4.24	4.30	4.33	4.34	4.35	4.35	4.36	4.36	4.37	4.37	4.38	4.38	4.39	4.39	4.39	4.39	4.40	4.40	4.40	4.40	4.40	4.40	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41	4.41

NATIONAL BANK
FINANCIAL MARKETS
A division of National Bank of Canada

MONTHLY FIXED INCOME MONITOR

Economics and Strategy Group

February 2015

Highlights

With central banks competing to weaken their respective currencies in support of exports, we think the Fed will have to revise its normalization strategy. We now see the upper bound of the target fed funds range ending the year at 0.75%. We also expect that euro-zone QE will have some spillover effect on prices of non-euro-zone financial assets, limiting any upward movement in the 10-year Treasury yield. We see it trading at 2.28% in December 2015.

In light of Statistics Canada revisions showing a material loss of momentum in the labor market in late 2014 and the impact of euro-zone QE on foreign exchange markets, we believe the Bank has to be more aggressive in its support to non-energy exports, higher investment and a stronger labor market. Accordingly we expect a 25 bps rate cut to be announced on March 4, 2015. Given the global outlook, 10-year Canadas are likely to be trading near 1.85% at year end.

Paul-André Pinsonnault

Forecast dated January 28, 2015

United States

Quarters	Fed Fund	3 Mth Bill	2YR	5YR	10YR	30YR
01/28/15	0.25	0.02	0.46	1.24	1.72	2.29
Q1/15	0.25	0.03	0.66	1.38	1.94	2.51
Q2	0.25	0.10	0.84	1.48	2.09	2.62
Q3	0.50	0.52	1.22	1.74	2.16	2.66
Q4	0.75	0.69	1.41	1.90	2.28	2.75
Q1/16	1.00	0.88	1.56	1.99	2.32	2.77
Q2	1.25	1.22	1.70	2.18	2.47	2.90
Q3	1.50	1.44	1.92	2.36	2.57	2.98
Q4	1.50	1.49	2.15	2.48	2.65	3.05

Canada

Quarters	Overnight	3 Mth Bill	2YR	5YR	10YR	30YR
01/28/15	0.75	0.60	0.44	0.69	1.35	1.93
Q1/15	0.50	0.46	0.55	0.79	1.42	1.96
Q2	0.50	0.46	0.63	0.86	1.47	1.97
Q3	0.50	0.46	0.68	0.90	1.53	2.02
Q4	0.50	0.46	0.78	1.27	1.84	2.30
Q1/16	0.50	0.46	0.88	1.36	1.91	2.34
Q2	0.50	0.53	0.89	1.42	1.96	2.37
Q3	0.75	0.79	1.16	1.69	2.09	2.48
Q4	1.00	0.96	1.26	1.76	2.12	2.51

MONTHLY ECONOMIC MONITOR

Canada
Economic Forecast

*(Annual % change)**	*2012*	*2013*	*2014*	*2015*	*2016*	*2014*	*Q4/Q4 2015*	*2016*
Gross domestic product (2007 $)	1.9	2.0	2.4	2.0	2.0	2.3	1.8	1.9
Consumption	1.9	2.5	2.8	2.2	2.0	2.7	1.9	1.9
Residential construction	5.7	(0.4)	2.5	1.0	(0.2)	4.7	(1.3)	0.0
Business investment	9.0	2.6	0.1	(1.2)	(0.1)	2.1	(3.1)	0.5
Government expenditures	0.2	0.1	(0.0)	(0.0)	(0.1)	0.6	(0.6)	0.2
Exports	2.6	2.0	5.2	6.5	6.6	5.9	7.9	5.2
Imports	3.7	1.3	1.4	4.1	3.6	1.4	5.0	3.0
Change in inventories (millions $)	7,437	12,368	3,922	5,000	5,249	(3,050)	4,886	4,566
Domestic demand	2.5	1.5	1.7	1.3	1.1	2.1	0.7	1.2
Real disposable income	2.8	2.5	1.7	1.9	1.9	1.7	1.9	1.9
Employment	1.2	1.3	0.8	1.0	1.1	1.0	0.9	1.0
Unemployment rate	7.3	7.1	6.9	6.7	6.5	6.6	6.6	6.4
Inflation	1.5	0.9	1.9	0.5	2.3	1.9	1.2	2.2
Before-tax profits	(4.2)	(0.6)	9.7	(0.9)	4.2	8.5	(0.7)	5.0
Current account (bil. $)	(59.9)	(56.3)	(43.6)	(52.6)	(44.5)	....	....	....

** or as noted*

Financial Forecast**

	Current 1/23/15	*Q1 2015*	*Q2 2015*	*Q3 2015*	*Q4 2015*	*2015*	*2016*
Overnight rate	0.75	0.75	0.50	0.50	0.50	0.50	1.00
Prime rate	2.75	2.75	2.50	2.50	2.50	2.50	3.00
3 month T-Bills	0.60	0.62	0.46	0.46	0.46	0.46	0.96
Treasury yield curve							
2-Year	0.54	0.63	0.63	0.68	0.78	0.78	1.26
5-Year	0.78	0.83	0.86	0.90	1.27	1.27	1.76
10-Year	1.33	1.42	1.47	1.53	1.84	1.84	2.12
30-Year	2.02	1.96	1.97	2.02	2.30	2.30	2.51
CAD per USD	1.24	1.26	1.26	1.27	1.28	1.28	1.23
Oil price (WTI), U.S.$	45	50	54	58	60	60	70

National Bank Financial

*** end of period*

RBC ECONOMICS | RESEARCH

FINANCIAL MARKET FORECASTS

February 4, 2015

Interest rates (%, end of quarter)

	Actual				Forecast								Actual		Forecast	
	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	2013	2014	2015	2016
Canada																
Overnight	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	0.75	1.00	1.50	2.00	1.00	1.00	0.50	2.00
Three-month	0.90	0.94	0.92	0.91	0.50	0.50	0.65	0.85	1.15	1.40	1.65	2.15	0.91	0.91	0.85	2.15
Two-year	1.07	1.10	1.13	1.01	0.55	0.70	0.85	1.05	1.50	1.75	2.00	2.30	1.13	1.01	1.05	2.30
Five-year	1.71	1.53	1.63	1.34	1.00	1.35	1.60	1.80	2.15	2.35	2.60	2.80	1.95	1.34	1.80	2.80
10-year	2.46	2.24	2.15	1.79	1.65	2.10	2.35	2.55	2.90	3.10	3.30	3.45	2.77	1.79	2.55	3.45
30-year	2.96	2.78	2.67	2.34	2.25	2.65	2.90	3.05	3.30	3.45	3.60	3.75	3.24	2.34	3.05	3.75
Yield curve (10s-2s)	139	114	102	78	110	140	150	150	140	135	130	115	164	78	150	115
United States																
Fed funds	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00	1.50	2.00	2.50	3.00	0.25	0.25	1.00	3.00
Three-month	0.05	0.04	0.02	0.04	0.10	0.40	0.65	0.90	1.40	1.90	2.40	2.80	0.07	0.04	0.90	2.80
Two-year	0.45	0.47	0.58	0.67	0.75	1.10	1.60	2.00	2.25	2.50	2.80	3.20	0.38	0.67	2.00	3.20
Five-year	1.74	1.62	1.78	1.65	1.65	1.95	2.20	2.50	3.00	3.15	3.30	3.50	1.75	1.65	2.50	3.50
10-year	2.73	2.53	2.52	2.17	2.25	2.65	2.90	3.10	3.55	3.70	3.85	4.00	3.04	2.17	3.10	4.00
30-year	3.55	3.34	3.21	2.75	2.85	3.25	3.50	3.75	4.10	4.25	4.35	4.50	3.96	2.75	3.75	4.50
Yield curve (10s-2s)	228	206	194	150	150	155	130	110	130	120	105	80	266	150	110	80
Yield spreads																
Three-month T-bills	0.85	0.90	0.90	0.87	0.40	0.10	0.00	-0.05	-0.25	-0.50	-0.75	-0.65	0.84	0.87	-0.05	-0.65
Two-year	0.62	0.63	0.55	0.34	-0.20	-0.40	-0.75	-0.95	-0.75	-0.75	-0.80	-0.90	0.75	0.34	-0.95	-0.90
Five-year	-0.03	-0.09	-0.15	-0.31	-0.65	-0.60	-0.60	-0.70	-0.85	-0.80	-0.70	-0.70	0.20	-0.31	-0.70	-0.70
10-year	-0.27	-0.29	-0.37	-0.38	-0.60	-0.55	-0.55	-0.55	-0.65	-0.60	-0.55	-0.55	-0.27	-0.38	-0.55	-0.55
30-year	-0.59	-0.56	-0.54	-0.41	-0.60	-0.60	-0.60	-0.70	-0.80	-0.80	-0.75	-0.75	-0.72	-0.41	-0.70	-0.75

Exchange rates (end of quarter)

	Actual				Forecast								Actual		Forecast	
	14Q1	14Q2	14Q3	14Q4	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	2013	2014	2015	2016
AUD/USD	0.93	0.94	0.87	0.82	0.75	0.74	0.73	0.72	0.71	0.71	0.70	0.70	0.89	0.82	0.72	0.70
USD/CAD	1.11	1.07	1.12	1.16	1.28	1.33	1.34	1.33	1.32	1.31	1.30	1.29	1.06	1.16	1.33	1.29
EUR/USD	1.38	1.37	1.26	1.21	1.07	1.05	1.07	1.11	1.15	1.16	1.16	1.17	1.38	1.21	1.11	1.17
USD/JPY	103.2	101.3	109.7	119.7	120.0	124.0	128.0	132.0	129.0	126.0	123.0	120.0	105.3	119.7	132.0	120.0
NZD/USD	0.87	0.88	0.78	0.78	0.69	0.67	0.65	0.64	0.63	0.63	0.62	0.62	0.82	0.78	0.64	0.62
USD/CHF	0.89	0.89	0.96	0.99	1.12	1.15	1.13	1.10	1.06	1.06	1.06	1.05	0.89	0.99	1.10	1.05
GBP/USD	1.67	1.71	1.62	1.56	1.47	1.40	1.41	1.44	1.47	1.49	1.49	1.50	1.66	1.56	1.44	1.50

Quarterly Forecasts

	2014		2015				2016			
Canada	Q3	Q4f	Q1f	Q2f	Q3f	Q4f	Q1f	Q2f	Q3f	Q4f
Real GDP (q/q, ann. % change)	2.8	2.4	1.2	1.5	1.7	1.9	2.0	2.0	2.2	2.3
Real GDP (y/y, % change)	2.6	2.5	2.5	2.0	1.7	1.6	1.8	1.9	2.0	2.1
Consumer Prices (y/y, % change)	2.1	1.9	0.9	0.4	0.6	1.4	1.9	2.1	2.1	2.1
Core CPI (y/y % change)	2.0	2.2	2.1	1.9	1.8	1.7	1.8	1.9	2.0	2.0
United States										
Real GDP (q/q, ann. % change)	5.0	2.6	2.4	2.6	3.0	3.1	3.0	2.9	2.8	2.8
Real GDP (y/y, % change)	2.7	2.5	3.6	3.2	2.7	2.8	2.9	3.0	2.9	2.9
Consumer Prices (y/y, % change)	1.8	1.2	0.4	0.2	0.4	1.2	2.0	2.1	2.2	2.2
Core CPI (y/y % change)	1.8	1.7	1.6	1.5	1.6	1.7	1.9	2.0	2.1	2.2

Financial Markets

Central Bank Rates

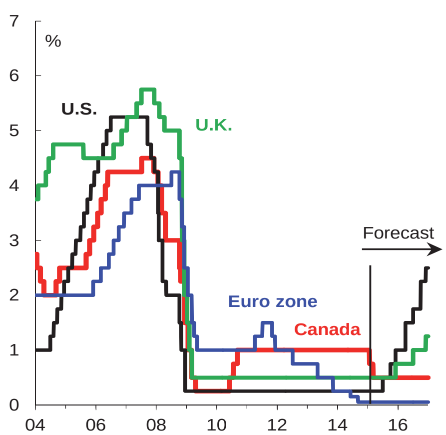
(%, end of period)

Americas	2014 Q3	Q4f	2015 Q1f	Q2f	Q3f	Q4f	2016 Q1f	Q2f	Q3f	Q4f
Bank of Canada	1.00	1.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
U.S. Federal Reserve	0.25	0.25	0.25	0.50	0.75	1.00	1.50	1.75	2.25	2.50
Bank of Mexico	3.00	3.00	3.00	3.25	3.75	4.00	4.50	4.75	5.25	5.75
Central Bank of Brazil	11.00	11.75	12.25	12.50	12.75	12.75	12.75	12.50	12.25	12.00
Bank of the Republic of Colombia	4.50	4.50	4.50	4.50	4.50	4.50	4.75	5.25	5.25	5.50
Central Reserve Bank of Peru	3.50	3.50	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Central Bank of Chile	3.25	3.00	3.00	3.00	3.00	3.00	3.25	3.50	3.75	4.00
Europe										
European Central Bank	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Bank of England	0.50	0.50	0.50	0.50	0.50	0.75	0.75	1.00	1.00	1.25
Swiss National Bank	0.00	-0.25	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75
Asia/Oceania										
Reserve Bank of Australia	2.50	2.50	2.25	2.25	2.25	2.25	2.50	2.75	3.00	3.25
People's Bank of China	6.00	5.60	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35
Reserve Bank of India	8.00	8.00	7.50	7.25	7.00	7.00	7.00	7.00	7.00	7.00
Bank of Korea	2.25	2.00	2.00	1.75	1.75	1.75	1.75	2.00	2.25	2.50
Bank Indonesia	7.50	7.75	7.75	7.75	7.75	7.75	7.75	8.00	8.00	8.00
Bank of Thailand	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.25	2.50	2.75
Canada										
3-month T-bill	0.92	0.92	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.60
2-year Canada	1.12	1.01	0.50	0.60	0.70	0.85	1.00	1.20	1.45	1.75
5-year Canada	1.63	1.34	0.80	0.95	1.10	1.25	1.45	1.75	2.10	2.30
10-year Canada	2.15	1.79	1.50	1.65	1.75	2.00	2.10	2.20	2.35	2.50
30-year Canada	2.67	2.34	1.95	2.15	2.25	2.50	2.60	2.70	2.85	3.00
United States										
3-month T-bill	0.02	0.04	0.10	0.60	1.10	1.60	1.85	2.10	2.40	2.60
2-year Treasury	0.57	0.66	0.70	1.10	1.50	1.90	2.15	2.30	2.55	2.75
5-year Treasury	1.76	1.65	1.30	1.60	1.90	2.15	2.30	2.45	2.60	2.80
10-year Treasury	2.49	2.17	1.90	2.10	2.25	2.50	2.60	2.70	2.85	3.00
30-year Treasury	3.20	2.75	2.35	2.60	2.75	3.00	3.10	3.20	3.35	3.50
Canada-U.S. Spreads										
3-month T-bill	0.90	0.88	0.40	-0.10	-0.60	-1.10	-1.35	-1.60	-1.90	-2.00
2-year	0.56	0.35	-0.20	-0.50	-0.80	-1.05	-1.15	-1.10	-1.10	-1.00
5-year	-0.13	-0.31	-0.50	-0.65	-0.80	-0.90	-0.85	-0.70	-0.50	-0.50
10-year	-0.34	-0.38	-0.40	-0.45	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50
30-year	-0.53	-0.41	-0.40	-0.45	-0.50	-0.50	-0.50	-0.50	-0.50	-0.50

Financial Markets

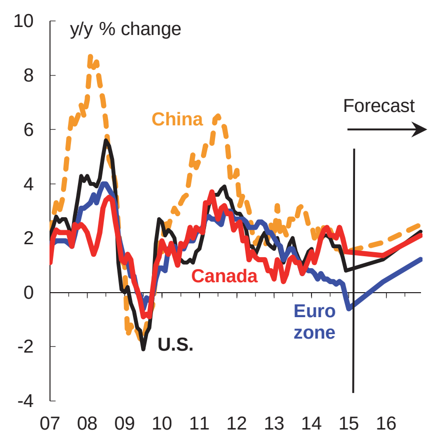
Exchange Rates	2014 Q3	2014 Q4	2015 Q1f	2015 Q2f	2015 Q3f	2015 Q4f	2016 Q1f	2016 Q2f	2016 Q3f	2016 Q4f
Americas					(end of period)					
Canadian Dollar (USDCAD)	1.12	1.16	1.28	1.31	1.32	1.33	1.33	1.32	1.31	1.30
Canadian Dollar (CADUSD)	0.89	0.86	0.78	0.76	0.76	0.75	0.75	0.76	0.76	0.77
Mexican Peso (USDMXN)	13.43	14.75	14.59	14.65	14.78	15.02	14.97	14.70	14.63	14.71
Brazilian Real (USDBRL)	2.45	2.66	2.70	2.75	2.80	2.85	2.85	2.90	2.95	3.00
Colombian Peso (USDCOP)	2025	2377	2380	2400	2450	2475	2500	2500	2475	2450
Peruvian Nuevo Sol (USDPEN)	2.89	2.98	3.05	3.10	3.15	3.10	3.08	3.06	3.04	3.02
Chilean Peso (USDCLP)	598	606	621	619	617	616	615	614	614	613
Canadian Dollar Cross Rates										
Euro (EURCAD)	1.41	1.41	1.45	1.44	1.43	1.40	1.40	1.37	1.34	1.30
U.K. Pound (GBPCAD)	1.82	1.81	1.89	1.94	1.98	2.00	2.01	1.99	1.98	1.96
Japanese Yen (CADJPY)	98	103	91	92	93	94	96	98	99	101
Australian Dollar (AUDCAD)	0.98	0.95	0.97	0.98	0.96	0.97	0.97	0.98	0.98	0.98
Mexican Peso (CADMXN)	11.99	12.69	11.40	11.19	11.20	11.29	11.26	11.14	11.17	11.32
Europe										
Euro (EURUSD)	1.26	1.21	1.13	1.10	1.08	1.05	1.05	1.04	1.02	1.00
U.K. Pound (GBPUSD)	1.62	1.56	1.48	1.48	1.50	1.50	1.51	1.51	1.51	1.51
Swiss Franc (USDCHF)	0.96	0.99	0.94	0.98	1.01	1.05	1.05	1.06	1.08	1.10
Swedish Krona (USDSEK)	7.21	7.81	8.30	8.40	8.45	8.58	8.58	8.50	8.50	8.50
Norwegian Krone (USDNOK)	6.43	7.45	7.70	7.87	7.90	7.90	7.90	7.85	7.75	7.70
Russian Ruble (USDRUB)	39.6	60.7	64.0	65.0	65.0	64.5	63.0	62.0	61.0	60.0
Turkish Lira (USDTRY)	2.28	2.34	2.35	2.40	2.45	2.47	2.45	2.43	2.40	2.37
Asia/Oceania										
Japanese Yen (USDJPY)	110	120	116	120	123	125	128	129	130	131
Australian Dollar (AUDUSD)	0.87	0.82	0.76	0.75	0.73	0.73	0.73	0.74	0.75	0.75
Chinese Yuan (USDCNY)	6.14	6.21	6.23	6.20	6.15	6.10	6.08	6.05	6.03	6.00
Indian Rupee (USDINR)	61.8	63.0	62.1	62.6	63.2	63.8	63.8	63.9	63.9	64.0
South Korean Won (USDKRW)	1055	1091	1110	1130	1150	1170	1165	1160	1155	1150
Indonesian Rupiah (USDIDR)	12188	12388	12760	12910	13055	13200	13150	13100	13050	13000
Thai Baht (USDTHB)	32.4	32.9	32.9	33.3	33.6	34.0	33.9	33.8	33.6	33.5

Central Bank Rates



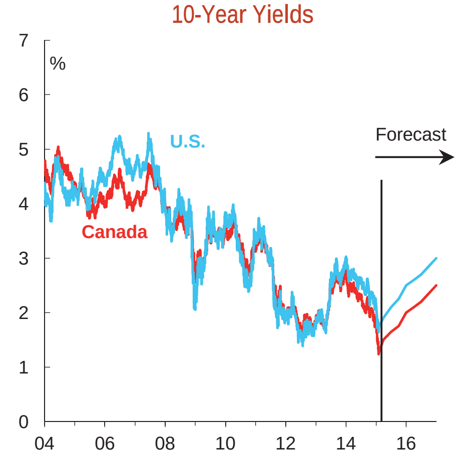
Source: Bloomberg, Scotiabank Economics.

Global Inflation



Source: Bloomberg, Scotiabank Economics.

10-Year Yields



Source: Bloomberg, Scotiabank Economics.

INTEREST RATE OUTLOOK

	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA												
Overnight Target Rate	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	1.00
3-mth T-Bill Rate	0.90	0.94	0.92	0.91	0.45	0.45	0.45	0.45	0.45	0.45	0.75	0.95
2-yr Govt. Bond Yield	1.07	1.10	1.13	1.01	0.50	0.55	0.60	0.85	1.05	1.20	1.35	1.65
5-yr Govt. Bond Yield	1.71	1.53	1.63	1.34	0.80	0.95	1.10	1.35	1.55	1.75	1.90	2.10
10-yr Govt. Bond Yield	2.46	2.24	2.15	1.79	1.35	1.65	1.70	1.90	2.05	2.20	2.30	2.40
30-yr Govt. Bond Yield	2.96	2.78	2.67	2.33	2.00	2.25	2.30	2.45	2.55	2.65	2.70	2.80
10-yr-2-yr Govt Spread	1.39	1.14	1.02	0.78	0.85	1.10	1.10	1.05	1.00	1.00	0.95	0.75
U.S.												
Fed Funds Target Rate	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00	1.00	1.00	1.25
3-mth T-Bill Rate	0.05	0.04	0.02	0.04	0.10	0.20	0.40	0.65	0.70	0.85	0.95	1.15
2-yr Govt. Bond Yield	0.44	0.47	0.58	0.67	0.50	0.80	1.00	1.25	1.40	1.65	1.90	2.00
5-yr Govt. Bond Yield	1.73	1.62	1.78	1.65	1.30	1.65	1.80	2.05	2.10	2.20	2.45	2.50
10-yr Govt. Bond Yield	2.73	2.53	2.52	2.17	1.80	2.10	2.10	2.30	2.40	2.50	2.70	2.75
30-yr Govt. Bond Yield	3.56	3.34	3.21	2.75	2.35	2.50	2.50	2.60	2.70	2.75	2.80	2.85
10-yr-2-yr Govt Spread	2.29	2.06	1.94	1.50	1.30	1.30	1.10	1.05	1.00	0.85	0.80	0.75
CANADA - U.S SPREADS												
Can - U.S. T-Bill Spread	0.85	0.90	0.90	0.87	0.35	0.25	0.05	-0.20	-0.25	-0.40	-0.20	-0.20
Can - U.S. 10-Year Bond Spread	-0.27	-0.29	-0.37	-0.38	-0.45	-0.45	-0.40	-0.40	-0.35	-0.30	-0.40	-0.35

E | F: Estimate | Forecast by TD Bank Group as at January 2015. All forecasts are end-of-period. Source: Bloomberg, Bank of Canada, Federal Reserve.

FOREIGN EXCHANGE OUTLOOK

Currency	Exchange rate	2014				2015				2016			
		Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Exchange rate to U.S. dollar													
Japanese yen	JPY per USD	103	101	110	120	120	121	123	125	125	125	127	127
Euro	USD per EUR	1.38	1.37	1.26	1.21	1.10	1.05	1.00	0.96	1.00	1.00	1.05	1.05
U.K. pound	USD per GBP	1.67	1.71	1.62	1.56	1.47	1.42	1.37	1.39	1.45	1.47	1.48	1.48
Exchange rate to Canadian dollar													
U.S. dollar	USD per CAD	0.91	0.94	0.89	0.86	0.81	0.80	0.79	0.77	0.75	0.79	0.82	0.85
Japanese yen	JPY per CAD	93.2	94.9	97.9	103.3	97.2	96.8	97.2	96.3	93.8	98.8	104.1	108.0
Euro	CAD per EUR	1.52	1.46	1.42	1.40	1.36	1.31	1.27	1.25	1.33	1.27	1.28	1.24
U.K. pound	CAD per GBP	0.54	0.55	0.55	0.55	0.55	0.56	0.58	0.55	0.52	0.54	0.55	0.58

E | F: Estimate | Forecast by TD Bank Group as at January 2015. All forecasts are end-of-period. Source: Federal Reserve, Bloomberg, TDBG.

COMMODITY PRICE FORECASTS

	2014				2015				2016				Annual Average		
	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	2014	2015F	2016F
Crude Oil (WTI, $US/bbl)	99	103	98	73	40	42	50	55	60	65	65	70	93	47	65
Natural Gas ($US/MMBtu)	5.17	4.59	3.94	3.83	3.20	3.10	3.30	3.60	3.80	3.40	3.50	3.70	4.38	3.30	3.60
Gold ($US/troy oz.)	1294	1289	1282	1201	1250	1290	1290	1300	1300	1300	1325	1325	1266	1283	1313
Silver (US$/troy oz.)	20.5	19.7	19.7	16.5	17.5	17.8	18.8	19.5	19.5	19.5	19.8	19.8	19.1	18.4	19.6
Copper (cents/lb)	319	308	317	301	250	270	285	285	280	280	285	285	311	273	283
Nickel (US$/lb)	6.64	8.38	8.42	7.19	6.90	8.00	9.00	9.50	11.00	12.00	12.50	12.50	7.66	8.35	12.00
Aluminum (Cents/lb)	77	82	90	89	79	85	90	90	90	90	100	100	85	86	95
Wheat ($US/bu)	9.32	8.90	8.43	8.05	7.90	7.80	8.00	8.15	8.25	8.40	8.55	8.75	8.68	7.96	8.49

E | F: Estimate | Forecast by TD Bank Group as at January 2015. All forecasts are period averages. Source: Bloomberg, USDA (Haver).

INTEREST RATE OUTLOOK	2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Fed Funds Target Rate (%)	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75	1.00	1.00	1.00	1.25
3-mth T-Bill Rate (%)	0.05	0.04	0.02	0.04	0.10	0.20	0.40	0.65	0.70	0.85	0.95	1.15
2-yr Govt. Bond Yield (%)	0.44	0.47	0.58	0.67	0.50	0.80	1.00	1.25	1.40	1.65	1.90	2.00
5-yr Govt. Bond Yield (%)	1.73	1.62	1.78	1.65	1.30	1.65	1.80	2.05	2.10	2.20	2.45	2.50
10-yr Govt. Bond Yield (%)	2.73	2.53	2.52	2.17	1.80	2.10	2.10	2.30	2.40	2.50	2.70	2.75
30-yr Govt. Bond Yield (%)	3.56	3.34	3.21	2.75	2.35	2.50	2.50	2.60	2.70	2.75	2.80	2.85
10-yr-2-yr Govt. Spread (%)	2.29	2.06	1.94	1.50	1.30	1.30	1.10	1.05	1.00	0.85	0.80	0.75

F: Forecast by TD Economics, January 2015; All forecasts are for end of period; Source: Bloomberg, TD Economics

FOREIGN EXCHANGE OUTLOOK		2014				2015				2016			
Currency	Exchange Rate	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Canadian dollar	CAD per USD	1.11	1.07	1.12	1.16	1.24	1.25	1.27	1.30	1.33	1.27	1.22	1.18
Japanese yen	JPY per USD	103	101	110	120	120	121	123	125	125	125	127	127
Euro	USD per EUR	1.38	1.37	1.26	1.21	1.10	1.05	1.00	0.96	1.00	1.00	1.05	1.05
U.K. pound	USD per GBP	1.67	1.71	1.62	1.56	1.47	1.42	1.37	1.39	1.45	1.47	1.48	1.48
Swiss franc	CHF per USD	0.88	0.89	0.96	0.99	0.91	0.95	1.00	1.04	1.00	1.00	0.95	0.95
Australian dollar	USD per AUD	0.93	0.94	0.87	0.82	0.82	0.81	0.79	0.78	0.78	0.78	0.76	0.75
NZ dollar	USD per NZD	0.87	0.88	0.78	0.78	0.77	0.75	0.71	0.69	0.69	0.68	0.66	0.65

F: Forecast by TD Economics, January 2015; All forecasts are for end of period; Source: Federal Reserve, Bloomberg, TD Economics

INTEREST RATE OUTLOOK	Annual Average						End of Period					
	13	14	15F	16F	17F	18F	13	14	15F	16F	17F	18F
U.S. FIXED INCOME												
Fed Funds Target Rate (%)	0.25	0.25	0.45	1.05	1.80	2.40	0.25	0.25	0.75	1.25	2.00	2.50
3-mth T-Bill Rate (%)	0.05	0.04	0.35	0.90	1.75	2.40	0.07	0.04	0.65	1.15	1.95	2.50
2-yr Govt. Bond Yield (%)	0.33	0.54	0.90	1.75	2.45	2.80	0.38	0.67	1.25	2.00	2.60	2.90
5-yr Govt. Bond Yield (%)	1.33	1.70	1.70	2.30	2.85	3.15	1.75	1.65	2.05	2.50	3.00	3.20
10-yr Govt. Bond Yield (%)	2.52	2.49	2.10	2.60	3.05	3.30	3.04	2.17	2.30	2.75	3.20	3.30
10-yr-2-yr Govt. Spread (%)	2.19	1.95	1.20	0.85	0.60	0.50	2.66	1.50	1.05	0.75	0.60	0.40
CANADIAN FIXED INCOME												
Overnight Target Rate (%)	1.00	1.00	0.50	0.65	1.40	2.25	1.00	1.00	0.50	1.00	1.50	2.50
3-mth T-Bill Rate (%)	0.97	0.92	0.45	0.65	1.35	2.25	0.91	0.91	0.45	0.95	1.45	2.50
2-yr Govt. Bond Yield (%)	1.14	1.08	0.65	1.30	1.95	2.60	1.13	1.01	0.85	1.65	2.15	2.85
5-yr Govt. Bond Yield (%)	1.73	1.55	1.05	1.85	2.35	2.95	1.95	1.34	1.35	2.10	2.55	3.15
10-yr Govt. Bond Yield (%)	2.38	2.16	1.65	2.25	2.65	3.10	2.77	1.79	1.90	2.40	2.80	3.25
10-yr-2-yr Govt. Spread (%)	1.24	1.08	1.00	0.95	0.70	0.50	1.64	0.78	1.05	0.75	0.65	0.40

F: Forecast by TD Economics, January 2015
Source: Statistics Canada, Bank of Canada, Bloomberg

Section:	Tab 11: Appendix 11.8	**Page No.:**	2
Topic:	Minimum Filing Requirements		
Subtopic:	Financial Results		
Issue:	Impact of Interim rate increase		

PREAMBLE TO IR (IF ANY):

The analysis provided at Appendix 11.8 includes the interim 2014/15 rate increase as base revenue, not as a separate rate increase.

QUESTION:

Please refile Appendix 11.8 including the interim rate increase for 2014/15 in the proposed rate increase line.

RATIONALE FOR QUESTION:

To understand the impact of the requested rate increases on the operating results of MH.

RESPONSE:

Please see the following table which includes the 2014/15 interim rate increase in the proposed rate increase line.

Net Income - Electricity Operations

	Actual							Forecast		
(in millions of $)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Revenue										
General Consumers Revenue										
- at approved rates	$ 1 075	$ 1 127	$ 1 145	$ 1 200	$ 1 193	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	-	-	-	-	-	(19)	(30)	(32)	(34)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	366	323	202	172	98	101	137	150	181	147
Other Revenue	8	16	6	6	14	30	22	15	14	14
	1 448	1 466	1 353	1 379	1 305	1 472	1 564	1 537	1 578	1 548
Expenses	1 112	1 209	1 193	1 240	1 243	1 407	1 439	1 495	1 571	1 653
Operating, Maintenance and Administrative	323	364	378	397	412	463	481	486	542	552
Finance Expense	401	433	373	388	385	452	435	495	510	548
Depreciation and Amortization	324	340	358	365	353	392	411	405	401	422
Capital and Other Taxes	57	64	76	81	83	86	97	99	107	121
Corporate Allocation	8	8	8	9	9	9	9	9	8	8
Other expenses	-	-	-	-	1	5	6	2	2	2
Non-controlling Interest	-	-	-	-	-	13	22	25	12	8
Net Income (loss) before proposed rate increases	$ 337	$ 257	$ 160	$ 139	$ 61	$ 78	$ 147	$ 67	$ 19	$ (97)
Proposed rate increases (2.75% May 1, 2014, 3.95% April 1, 2015 and 3.95% April 1, 2016)	-	-	-	-	-	-	-	35	96	157
Net Income including proposed rate increases	$ 337	$ 257	$ 160	$ 139	$ 61	$ 78	$ 147	$ 102	$ 115	$ 59

Retained Earnings and Financial Ratios (without proposed rate increases)

Retained Earnings (electric operations)	$ 1 784	$ 2 028	$ 2 190	$ 2 328	$ 2 390	$ 2 468	$ 2 614	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	73:27	77:23	72:28	72:28	74:26	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including proposed rate increases)

Retained Earnings (electric operations)	$ 1 784	$ 2 028	$ 2 190	$ 2 328	$ 2 390	$ 2 468	$ 2 614	$ 2 717	$ 2 778	$ 2 837
Debt to Equity Ratio (electric operations)	73:27	77:23	72:28	72:28	74:26	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	1.13	1.25	1.16	1.16	1.07
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	1.26	1.39	0.98	1.02	0.94

Section:	Interim Application PUB/MH I-5	Page No.:	
Topic:	Forecast Financial Results		
Subtopic:	Changes between IFF13 and IFF14		
Issue:	Forecast Accuracy		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update PUB/MH I-5(a) from the April 2014 interim rate application to include two additional columns, namely the IFF14/actual and the difference between IFF14 and IFF13.

RATIONALE FOR QUESTION:

To assess MH's forecasting accuracy in the near term.

RESPONSE:

Please see the response to PUB/MH-I-63a.

Section:	Interim Application PUB/MH I-5	**Page No.:**	
Topic:	Forecast Financial Results		
Subtopic:	Changes between IFF13 and IFF14		
Issue:	Forecast Accuracy		

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide a similar analysis to PUB/MH I-5(b) for 2013/14, 2014/15 and 2015/16 comparing IFF14/actual to IFF13.

RATIONALE FOR QUESTION:

To assess MH's forecasting accuracy in the near term.

RESPONSE:

Please see the response to PUB/MH-I-63c.

Section:		**Page No.:**	
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	Scope of Hearing		
Issue:	LWR license renewal potential impact on MH's revenues		

PREAMBLE TO IR (IF ANY):

MH has indicated the regions of interest are:

- Physical structures/works Lake Winnipeg to Jenpeg
- LWR influences on Nelson River Water regime
- Downstream of Gull Rapids the operation of the Kettle Generation Station
- Lake Winnipeg stakeholders continue to have a variety of concerns about LWR

QUESTION:

Explain how these regions of interest will be addressed by various interveners.

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH's revenues.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:		Page No.:	
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	Scope of Hearing		
Issue:	LWR license renewal potential impact on MH's revenues		

PREAMBLE TO IR (IF ANY):

MH has indicated the regions of interest are:

- Physical structures/works Lake Winnipeg to Jenpeg
- LWR influences on Nelson River Water regime
- Downstream of Gull Rapids the operation of the Kettle Generation Station
- Lake Winnipeg stakeholders continue to have a variety of concerns about LWR

QUESTION:

Elaborate on the interveners and their specific concerns and identify what expert resources will be funded in each area of interest.

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH's revenues.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:		**Page No.:**	
Topic:	CEC Hearings - Lake Winnipeg Regulation (LWR)		
Subtopic:	Public Sessions		
Issue:	LWR license renewal potential impact on MH’s revenues		

PREAMBLE TO IR (IF ANY):

Public sessions are scheduled during Jan/Feb/Mar in Northern Manitoba, in Lake Winnipeg communities and three in Winnipeg. Presumably MH will make the same customer presentation at each session.

QUESTION:

Provide MH's presentation documentation(s) as well as the license application.

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH’s revenues.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:		**Page No.:**	
Topic:	CEC Hearings - Lake Winnipeg Regulation (LWR)		
Subtopic:	Public Sessions		
Issue:	LWR license renewal potential impact on MH's revenues		

PREAMBLE TO IR (IF ANY):

Public sessions are scheduled during Jan/Feb/Mar in Northern Manitoba, in Lake Winnipeg communities and three in Winnipeg. Presumably MH will make the same customer presentation at each session.

QUESTION:

Provide the anticipated CEC hearing timetable and expected report date

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH's revenues.

RESPONSE:

Pursuant to PUB Order 33/15, no response is required to this Information Request.

Section:		**Page No.:**	
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	License Renewal Alternatives		
Issue:	Cost/Benefit Implications		

PREAMBLE TO IR (IF ANY):

MH has suggested three alternatives for the LWR operation license. These are:

- Maintain the existing 711-715 foot operation range, and maximize JenPeg spillway and power house flows when Lake Winnipeg levels exceed 715 feet.
- Reduce operating range to 711-714 feet, maximizing Jenpeg spillway and power house flows when Lake Winnipeg levels exceed 714 feet.
- Raise the operating range to 711-716 feet, maximizing spillway and power house flows when Lake Winnipeg levels exceed 716 feet

QUESTION:

Provide IFF14 twenty-year outlooks for each of the above three operating scenarios. Please include all assumptions around each scenario.

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH's revenue requirement.

RESPONSE:

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 three LWR operating range scenarios are available based on pre-existing analysis using NFAT Plan 14 (Keeyask 2019/Conawapa 2025/750 MW Interconnection) as the base scenario for maintaining the existing 711-715 operating range.

One Foot Decrease in the LWR Operating Range

Under an average of all historic flows, the reduced LWR operating range results in lower dependable energy which requires the advancement of energy resources to around 2024/25 at an in-service cost of approximately $100 million. Projected net extraprovincial revenues (net of water rentals and fuel and power purchases) are approximately $480 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 $330 million. Overall, retained earnings are $830 million lower compared to the base scenario by 2031/32. In order to achieve the target 75:25 debt/equity ratio by 2031/32, equal annual rate increases of 4.08% from 2014/15 to 2031/32 would be necessary.

One Foot Increase in the LWR Operating Range

Under an average of all historic flows, the increased LWR operating range results in additional dependable energy which eliminates the need for additional energy resources in the 20-year forecast horizon. Net extraprovincial revenues are approximately $420 million higher compared to the base scenario due to higher long-term firm export sales and lower power purchased partially offset by lower opportunity export sales and higher thermal requirements. Assuming the same 3.95% even annual rate increases as the base scenario, projected finance expense is approximately $180 million lower resulting in higher cumulative net income of approximately $590 million over the 20-year forecast period to 2031/32 compared to the base scenario. In order to achieve the target 75:25 debt/equity ratio by 2031/32, equal annual rate increases of 3.85% from 2014/15 to 2031/32 would be necessary.

It is noted that scenarios compared against MH14 are not available; however, the NFAT-based scenarios provide a reasonable indication of the directional impacts. The suspension of Conawapa assumed in MH14 is expected to dampen the effects of the LWR operating range adjustments on net extraprovincial revenue for the forecast years Conawapa would have been in-service due to the subtraction of Conawapa dependable energy. Additionally, the advancement of the additional energy resources in the one foot decrease scenario is not likely necessary as early as 2024/25 due to the higher DSM energy and capacity savings assumed in MH14.

Development Plan NFAT PDP (14) - BASE SCENARIO - MAINTAIN EXISTING LWR 711-715 OPERATING RANGE
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers Revenue at approved rates	1,331	1,361	1,374	1,390	1,404	1,424	1,447	1,462	1,485	1,506
Additional General Consumers Revenue	-	48	104	164	228	297	370	447	530	619
Extraprovincial	357	344	333	370	388	412	402	439	713	817
Other	14	15	15	15	15	16	16	16	17	17
Total Revenue	1,702	1,768	1,826	1,939	2,035	2,148	2,236	2,364	2,745	2,959
EXPENSES										
Operating and Administrative	455	471	546	559	570	593	605	621	678	690
Finance Expense	452	442	491	519	577	658	774	783	989	1,083
Depreciation and Amortization	399	430	372	391	400	422	458	461	518	553
Water Rentals and Assessments	117	116	112	112	112	112	112	114	124	127
Fuel and Power Purchased	143	166	167	178	191	200	205	207	222	239
Capital and Other Taxes	87	95	101	109	119	127	134	141	149	158
Corporate Allocation	9	9	8	8	8	8	8	8	8	8
Total Expenses	1,663	1,729	1,798	1,877	1,978	2,121	2,297	2,335	2,688	2,859
Non-Controlling Interest	(14)	(24)	(23)	(17)	(14)	(13)	(9)	(9)	(7)	1
Net Income	54	63	51	79	72	40	(53)	38	63	100
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	0.00%	3.50%	7.59%	11.83%	16.25%	20.83%	25.60%	30.56%	35.72%	41.07%
Debt Ratio	76	78	84	85	86	87	88	89	89	90
Interest Coverage Ratio	1.09	1.10	1.07	1.10	1.08	1.04	0.95	1.03	1.05	1.08
Capital Coverage Ratio	1.09	0.90	0.77	0.90	1.21	1.36	1.08	1.55	1.52	1.57

Development Plan	NFAT PDP (14) - BASE SCENARIO - MAINTAIN EXISTING LWR 711-715 OPERATING RANGE
Development Plan Scenario	REFERENCE

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers Revenue at approved rates	1,529	1,552	1,575	1,598	1,621	1,644	1,669	1,693	1,717	1,741
Additional General Consumers Revenue	713	814	921	1,034	1,154	1,282	1,418	1,562	1,715	1,876
Extraprovincial	829	808	795	834	1,099	1,165	1,174	1,168	1,176	1,181
Other	17	18	18	18	19	19	19	20	20	21
Total Revenue	3,088	3,191	3,309	3,484	3,892	4,110	4,280	4,443	4,628	4,818
EXPENSES										
Operating and Administrative	703	716	730	760	773	788	804	817	832	849
Finance Expense	1,075	1,083	1,077	1,182	1,403	1,584	1,553	1,515	1,523	1,459
Depreciation and Amortization	559	558	561	600	668	721	724	732	758	766
Water Rentals and Assessments	128	128	127	135	148	150	151	151	152	153
Fuel and Power Purchased	247	256	270	233	238	256	266	275	282	292
Capital and Other Taxes	166	174	181	187	190	192	195	197	201	202
Corporate Allocation	8	8	8	8	8	8	8	8	7	7
Total Expenses	2,887	2,924	2,955	3,105	3,428	3,700	3,701	3,695	3,756	3,728
Non-Controlling Interest	3	7	9	5	7	9	11	14	16	18
Net Income	199	260	345	373	457	401	567	735	857	1,072
Additional General Consumers Revenue Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	46.64%	52.43%	58.45%	64.70%	71.20%	77.96%	84.98%	92.28%	99.87%	107.76%
Debt Ratio	90	89	88	87	86	85	83	81	78	75
Interest Coverage Ratio	1.14	1.17	1.22	1.23	1.28	1.25	1.35	1.46	1.55	1.72
Capital Coverage Ratio	1.58	1.66	1.84	2.07	2.67	2.33	2.45	2.61	2.72	3.61

Development Plan	NFAT PDP (14) - BASE SCENARIO - MAINTAIN EXISTING LWR 711-715 OPERATING RANGE
Development Plan Scenario	REFERENCE

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	15,374	16,436	17,108	18,261	18,821	22,520	22,947	25,701	29,723	30,257
Accumulated Depreciation	(5,173)	(5,536)	(5,856)	(6,223)	(6,612)	(7,028)	(7,482)	(7,938)	(8,450)	(8,997)
Net Plant in Service	10,201	10,900	11,251	12,038	12,209	15,492	15,465	17,762	21,273	21,259
Construction in Progress	2,105	2,866	4,164	5,048	6,617	5,069	6,411	5,209	2,873	4,555
Current and Other Assets	1,869	1,735	1,391	1,579	1,791	2,029	1,845	1,968	2,032	1,696
Goodwill and Intangible Assets	180	165	151	136	126	116	140	147	231	224
Regulated Assets	231	225	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	14,587	15,890	16,958	18,802	20,742	22,707	23,861	25,086	26,409	27,735
LIABILITIES AND EQUITY										
Long Term Debt	9,289	11,260	12,802	14,474	16,170	17,742	19,438	20,404	21,727	23,077
Current and Other Liabilities	2,231	1,503	1,659	1,795	2,007	2,381	1,904	2,140	2,092	1,988
Contributions in Aid of Construction	325	334	339	344	348	358	364	371	378	385
Retained Earnings	2,442	2,505	2,299	2,378	2,450	2,490	2,437	2,475	2,538	2,638
Accumulated Other Comprehensive Income	299	287	(142)	(189)	(232)	(264)	(283)	(303)	(326)	(354)
Total Liabilities and Equity	14,587	15,890	16,958	18,802	20,742	22,707	23,861	25,086	26,409	27,735

Development Plan: NFAT PDP (14) - BASE SCENARIO - MAINTAIN EXISTING LWR 711-715 OPERATING RANGE
Development Plan Scenario: REFERENCE

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	30,788	31,353	32,042	37,329	42,227	43,649	44,393	44,951	46,932	47,662
Accumulated Depreciation	(9,552)	(10,107)	(10,666)	(11,264)	(11,930)	(12,650)	(13,373)	(14,103)	(14,861)	(15,626)
Net Plant in Service	21,237	21,246	21,376	26,065	30,297	30,999	31,021	30,848	32,072	32,035
Construction in Progress	6,192	7,589	8,716	5,044	1,293	744	1,075	1,515	472	545
Current and Other Assets	1,782	2,083	2,335	2,173	2,461	2,758	3,115	3,351	3,339	4,380
Goodwill and Intangible Assets	218	214	210	207	203	199	196	192	188	185
Regulated Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	29,430	31,133	32,637	33,488	34,255	34,700	35,406	35,906	36,071	37,145
LIABILITIES AND EQUITY										
Long Term Debt	25,080	26,482	27,235	28,038	28,239	28,380	28,331	27,634	27,623	27,396
Current and Other Liabilities	1,491	1,523	1,921	1,590	1,690	1,586	1,766	2,219	1,531	1,751
Contributions in Aid of Construction	392	400	407	415	422	430	438	446	455	463
Retained Earnings	2,837	3,097	3,443	3,816	4,273	4,673	5,241	5,975	6,832	7,904
Accumulated Other Comprehensive Income	(370)	(370)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)
Total Liabilities and Equity	29,430	31,133	32,637	33,488	34,255	34,700	35,406	35,906	36,071	37,145

Development Plan NFAT PDP (14) - BASE SCENARIO - MAINTAIN EXISTING LWR 711-715 OPERATING RANGE
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,692	1,768	1,826	1,939	2,035	2,148	2,236	2,364	2,745	2,959
Cash Paid to Suppliers and Employees	(782)	(822)	(900)	(931)	(963)	(1,001)	(1,024)	(1,048)	(1,136)	(1,175)
Interest Paid	(466)	(474)	(510)	(558)	(604)	(699)	(814)	(816)	(1,031)	(1,127)
Interest Received	28	17	24	26	31	39	41	38	35	33
Cash from Operating Activities	473	488	440	476	499	487	439	539	613	690
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	836	2,170	1,760	1,990	2,180	2,380	1,990	1,590	1,990	1,790
Sinking Fund Withdrawals	129	393	102	26	-	15	416	184	265	676
Retirement of Long Term Debt	(119)	(808)	(176)	(312)	(347)	(530)	(829)	(306)	(635)	(679)
Other Financing Activities	(42)	(7)	(16)	(18)	(16)	(12)	(24)	(13)	(34)	(9)
Cash from Financing Activities	804	1,748	1,670	1,685	1,817	1,852	1,554	1,455	1,586	1,777
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(1,378)	(1,913)	(2,010)	(2,041)	(2,124)	(2,023)	(1,791)	(1,635)	(1,865)	(2,199)
Sinking Fund Payment	(107)	(208)	(124)	(188)	(165)	(227)	(216)	(220)	(248)	(338)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)
Cash from Investing Activities	(1,502)	(2,138)	(2,155)	(2,249)	(2,321)	(2,292)	(2,035)	(1,884)	(2,146)	(2,575)
Net Increase (Decrease) in Cash	(225)	99	(44)	(87)	(5)	48	(42)	110	54	(108)
Cash at Beginning of Year	43	(183)	(84)	(128)	(215)	(220)	(172)	(215)	(105)	(51)
Cash at End of Year	(183)	(84)	(128)	(215)	(220)	(172)	(215)	(105)	(51)	(160)

Development Plan NFAT PDP (14) - BASE SCENARIO - MAINTAIN EXISTING LWR 711-715 OPERATING RANGE
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,088	3,191	3,309	3,484	3,892	4,110	4,280	4,443	4,628	4,818
Cash Paid to Suppliers and Employees	(1,202)	(1,230)	(1,262)	(1,266)	(1,297)	(1,331)	(1,357)	(1,378)	(1,402)	(1,427)
Interest Paid	(1,091)	(1,093)	(1,097)	(1,218)	(1,441)	(1,639)	(1,625)	(1,596)	(1,619)	(1,530)
Interest Received	17	19	28	33	41	55	71	78	89	70
Cash from Operating Activities	812	886	978	1,033	1,195	1,196	1,369	1,547	1,696	1,931
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	1,960	1,390	1,190	790	190	190	190	(40)	(10)	(10)
Sinking Fund Withdrawals	156	-	-	450	-	-	60	250	700	13
Retirement of Long Term Debt	(432)	-	-	(450)	-	-	(60)	(220)	(700)	(13)
Other Financing Activities	(1)	(1)	(1)	(1)	(1)	(9)	(8)	(8)	(7)	(26)
Cash from Financing Activities	1,683	1,389	1,189	789	189	181	182	(18)	(17)	(36)
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(2,151)	(1,943)	(1,798)	(1,596)	(1,129)	(853)	(1,056)	(977)	(919)	(781)
Sinking Fund Payment	(245)	(263)	(288)	(311)	(310)	(325)	(339)	(351)	(353)	(331)
Other Investing Activities	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)
Cash from Investing Activities	(2,425)	(2,239)	(2,111)	(1,932)	(1,467)	(1,204)	(1,420)	(1,355)	(1,298)	(1,138)
Net Increase (Decrease) in Cash	69	37	57	(111)	(83)	172	130	174	381	757
Cash at Beginning of Year	(160)	(90)	(53)	4	(107)	(190)	(18)	113	287	668
Cash at End of Year	(90)	(53)	4	(107)	(190)	(18)	113	287	668	1,425

Development Plan NFAT PDP (14) - 1 FOOT DECREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers Revenue at approved rates	1,331	1,361	1,374	1,390	1,404	1,424	1,447	1,462	1,485	1,506
Additional General Consumers Revenue	-	48	104	164	228	297	370	447	530	619
Extraprovincial	357	344	328	356	369	391	395	418	700	805
Other	14	15	15	15	15	16	16	16	17	17
Total Revenue	1,702	1,768	1,820	1,925	2,016	2,128	2,229	2,343	2,731	2,947
EXPENSES										
Operating and Administrative	455	471	546	559	570	593	605	621	677	690
Finance Expense	452	442	492	519	579	662	779	789	997	1,093
Depreciation and Amortization	399	430	372	391	400	422	458	461	518	553
Water Rentals and Assessments	117	116	111	112	111	111	111	113	124	127
Fuel and Power Purchased	143	166	173	177	191	199	216	213	228	244
Capital and Other Taxes	87	95	101	109	119	127	134	141	149	158
Corporate Allocation	9	9	8	8	8	8	8	8	8	8
Total Expenses	1,663	1,729	1,803	1,876	1,978	2,122	2,312	2,346	2,701	2,873
Non-Controlling Interest	(14)	(24)	(23)	(17)	(14)	(13)	(9)	(9)	(7)	1
Net Income	54	63	39	66	52	18	(75)	5	37	74
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	0.00%	3.50%	7.59%	11.83%	16.25%	20.83%	25.60%	30.56%	35.72%	41.07%
Debt Ratio	76	78	84	85	86	88	89	89	90	90
Interest Coverage Ratio	1.09	1.10	1.06	1.09	1.06	1.02	0.93	1.00	1.03	1.06
Capital Coverage Ratio	1.09	0.90	0.75	0.87	1.16	1.31	1.02	1.44	1.45	1.51

Development Plan NFAT PDP (14) - 1 FOOT DECREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers Revenue at approved rates	1,529	1,552	1,575	1,598	1,621	1,644	1,669	1,693	1,717	1,741
Additional General Consumers Revenue	713	814	921	1,034	1,154	1,282	1,418	1,562	1,715	1,876
Extraprovincial	806	790	784	807	1,058	1,131	1,131	1,123	1,132	1,134
Other	17	18	18	18	19	19	19	20	20	21
Total Revenue	3,065	3,172	3,299	3,457	3,851	4,076	4,237	4,398	4,584	4,772
EXPENSES										
Operating and Administrative	703	716	729	759	772	787	803	816	831	848
Finance Expense	1,087	1,097	1,094	1,206	1,430	1,618	1,591	1,556	1,567	1,508
Depreciation and Amortization	559	558	561	604	671	725	727	735	762	770
Water Rentals and Assessments	127	127	127	135	147	150	150	151	152	152
Fuel and Power Purchased	252	262	273	226	238	258	268	276	284	292
Capital and Other Taxes	166	175	182	188	191	193	195	197	202	202
Corporate Allocation	8	8	8	8	8	8	8	8	7	7
Total Expenses	2,902	2,943	2,974	3,126	3,457	3,738	3,743	3,738	3,803	3,780
Non-Controlling Interest	3	7	9	5	7	9	11	14	16	18
Net Income	160	223	316	325	387	328	483	646	765	974
Additional General Consumers Revenue Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	46.64%	52.43%	58.45%	64.70%	71.20%	77.96%	84.98%	92.28%	99.87%	107.76%
Debt Ratio	90	90	89	89	87	86	85	83	81	78
Interest Coverage Ratio	1.11	1.15	1.20	1.20	1.23	1.20	1.29	1.40	1.48	1.64
Capital Coverage Ratio	1.51	1.60	1.78	1.99	2.52	2.20	2.31	2.47	2.58	3.44

Development Plan — NFAT PDP (14) - 1 FOOT DECREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario — REFERENCE

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	15,374	16,436	17,108	18,261	18,821	22,520	22,947	25,701	29,723	30,257
Accumulated Depreciation	(5,173)	(5,536)	(5,856)	(6,223)	(6,612)	(7,028)	(7,482)	(7,938)	(8,450)	(8,997)
Net Plant in Service	10,201	10,900	11,251	12,038	12,209	15,492	15,465	17,762	21,273	21,259
Construction in Progress	2,105	2,866	4,164	5,048	6,617	5,069	6,411	5,209	2,873	4,555
Current and Other Assets	1,869	1,735	1,391	1,579	1,791	2,029	1,846	1,969	2,032	1,696
Goodwill and Intangible Assets	180	165	151	136	126	116	140	147	231	224
Regulated Assets	231	225	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	14,587	15,890	16,958	18,802	20,742	22,707	23,861	25,087	26,409	27,735
LIABILITIES AND EQUITY										
Long Term Debt	9,289	11,260	12,802	14,474	16,170	17,742	19,638	20,404	21,727	23,277
Current and Other Liabilities	2,231	1,503	1,670	1,819	2,050	2,447	1,793	2,261	2,238	1,961
Contributions in Aid of Construction	325	334	339	344	348	358	364	371	378	385
Retained Earnings	2,442	2,505	2,288	2,354	2,406	2,424	2,349	2,354	2,392	2,466
Accumulated Other Comprehensive Income	299	287	(142)	(189)	(232)	(264)	(283)	(303)	(326)	(354)
Total Liabilities and Equity	14,587	15,890	16,958	18,802	20,742	22,707	23,861	25,087	26,409	27,735

Development Plan	NFAT PDP (14) - 1 FOOT DECREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario	REFERENCE

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	30,788	31,353	32,144	37,432	42,330	43,752	44,496	45,054	47,035	47,764
Accumulated Depreciation	(9,552)	(10,107)	(10,666)	(11,268)	(11,937)	(12,660)	(13,386)	(14,120)	(14,881)	(15,650)
Net Plant in Service	21,237	21,246	21,479	26,164	30,393	31,091	31,110	30,933	32,154	32,114
Construction in Progress	6,229	7,678	8,716	5,044	1,293	744	1,075	1,515	472	545
Current and Other Assets	1,784	2,097	2,339	2,185	2,478	2,787	3,081	3,231	3,131	4,282
Goodwill and Intangible Assets	218	214	210	207	203	199	196	192	188	185
Regulated Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	29,468	31,235	32,744	33,600	34,367	34,821	35,461	35,871	35,945	37,126
LIABILITIES AND EQUITY										
Long Term Debt	25,280	26,882	27,435	28,438	28,839	28,980	28,931	28,234	28,223	28,196
Current and Other Liabilities	1,540	1,475	2,107	1,628	1,599	1,576	1,774	2,227	1,539	1,763
Contributions in Aid of Construction	392	400	407	415	422	430	438	446	455	463
Retained Earnings	2,625	2,848	3,164	3,489	3,876	4,204	4,688	5,333	6,098	7,073
Accumulated Other Comprehensive Income	(370)	(370)	(369)	(369)	(369)	(369)	(369)	(369)	(369)	(369)
Total Liabilities and Equity	29,468	31,235	32,744	33,600	34,367	34,821	35,461	35,871	35,945	37,126

Development Plan NFAT PDP (14) - 1 FOOT DECREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,692	1,768	1,820	1,925	2,016	2,128	2,229	2,343	2,731	2,947
Cash Paid to Suppliers and Employees	(782)	(822)	(905)	(929)	(962)	(999)	(1,034)	(1,053)	(1,141)	(1,179)
Interest Paid	(466)	(474)	(510)	(558)	(605)	(699)	(819)	(828)	(1,038)	(1,134)
Interest Received	28	17	24	26	31	39	41	38	35	33
Cash from Operating Activities	473	488	430	463	481	468	416	500	587	667
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	836	2,170	1,760	1,990	2,180	2,380	2,190	1,390	1,990	1,990
Sinking Fund Withdrawals	129	393	102	26	-	15	416	184	266	676
Retirement of Long Term Debt	(119)	(808)	(176)	(312)	(347)	(530)	(829)	(306)	(635)	(679)
Other Financing Activities	(42)	(7)	(16)	(18)	(16)	(12)	(24)	(13)	(34)	(9)
Cash from Financing Activities	804	1,748	1,670	1,685	1,817	1,852	1,754	1,255	1,587	1,977
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(1,378)	(1,913)	(2,010)	(2,041)	(2,124)	(2,023)	(1,791)	(1,635)	(1,865)	(2,199)
Sinking Fund Payment	(107)	(208)	(124)	(188)	(165)	(227)	(217)	(221)	(248)	(338)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)
Cash from Investing Activities	(1,502)	(2,138)	(2,155)	(2,249)	(2,321)	(2,292)	(2,036)	(1,885)	(2,146)	(2,575)
Net Increase (Decrease) in Cash	(225)	99	(55)	(100)	(24)	29	134	(129)	29	69
Cash at Beginning of Year	43	(183)	(84)	(139)	(239)	(262)	(233)	(99)	(228)	(199)
Cash at End of Year	(183)	(84)	(139)	(239)	(262)	(233)	(99)	(228)	(199)	(131)

Development Plan NFAT PDP (14) - 1 FOOT DECREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,065	3,172	3,299	3,457	3,851	4,076	4,237	4,398	4,584	4,772
Cash Paid to Suppliers and Employees	(1,207)	(1,236)	(1,264)	(1,259)	(1,295)	(1,332)	(1,358)	(1,378)	(1,402)	(1,426)
Interest Paid	(1,102)	(1,103)	(1,116)	(1,239)	(1,469)	(1,673)	(1,663)	(1,638)	(1,665)	(1,578)
Interest Received	17	19	29	33	41	56	72	80	91	72
Cash from Operating Activities	773	852	947	993	1,128	1,127	1,288	1,461	1,608	1,841
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	1,960	1,590	990	990	390	190	190	(40)	(10)	190
Sinking Fund Withdrawals	156	-	-	450	-	-	60	250	700	13
Retirement of Long Term Debt	(432)	-	-	(450)	-	-	(60)	(220)	(700)	(13)
Other Financing Activities	(1)	(1)	(1)	(1)	(1)	(9)	(8)	(8)	(7)	(26)
Cash from Financing Activities	1,683	1,589	989	989	389	181	182	(18)	(17)	164
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(2,188)	(1,996)	(1,811)	(1,596)	(1,129)	(853)	(1,056)	(977)	(919)	(781)
Sinking Fund Payment	(247)	(266)	(292)	(315)	(315)	(331)	(346)	(358)	(360)	(338)
Other Investing Activities	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)
Cash from Investing Activities	(2,463)	(2,294)	(2,128)	(1,937)	(1,471)	(1,210)	(1,427)	(1,362)	(1,305)	(1,146)
Net Increase (Decrease) in Cash	(8)	148	(192)	45	46	98	43	82	285	859
Cash at Beginning of Year	(131)	(139)	9	(183)	(137)	(91)	6	49	131	416
Cash at End of Year	(139)	9	(183)	(137)	(91)	6	49	131	416	1,275

Development Plan NFAT PDP (14) - 1 FOOT INCREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers Revenue at approved rates	1,331	1,361	1,374	1,390	1,404	1,424	1,447	1,462	1,485	1,506
Additional General Consumers Revenue	-	48	104	164	228	297	370	447	530	619
Extraprovincial	357	344	346	385	400	428	417	451	733	835
Other	14	15	15	15	15	16	16	16	17	17
Total Revenue	1,702	1,768	1,839	1,954	2,047	2,165	2,250	2,376	2,764	2,977
EXPENSES										
Operating and Administrative	455	471	547	560	571	594	606	621	678	690
Finance Expense	452	442	491	519	577	658	772	780	986	1,078
Depreciation and Amortization	399	430	372	391	400	422	458	461	518	553
Water Rentals and Assessments	117	116	113	113	113	113	112	114	125	128
Fuel and Power Purchased	143	166	167	181	193	202	210	212	221	235
Capital and Other Taxes	87	95	101	109	119	127	134	141	149	158
Corporate Allocation	9	9	8	8	8	8	8	8	8	8
Total Expenses	1,663	1,729	1,800	1,881	1,980	2,124	2,301	2,337	2,684	2,850
Non-Controlling Interest	(14)	(24)	(23)	(17)	(14)	(13)	(9)	(9)	(7)	1
Net Income	54	63	62	89	82	54	(42)	47	87	125
Additional General Consumers Revenue Percent Increase	0.00%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	0.00%	3.50%	7.59%	11.83%	16.25%	20.83%	25.60%	30.56%	35.72%	41.07%
Debt Ratio	76	78	84	85	86	87	88	89	89	89
Interest Coverage Ratio	1.09	1.10	1.09	1.12	1.09	1.05	0.96	1.04	1.07	1.10
Capital Coverage Ratio	1.09	0.90	0.79	0.93	1.24	1.40	1.10	1.56	1.57	1.63

Development Plan NFAT PDP (14) - 1 FOOT INCREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers Revenue at approved rates	1,529	1,552	1,575	1,598	1,621	1,644	1,669	1,693	1,717	1,741
Additional General Consumers Revenue	713	814	921	1,034	1,154	1,282	1,418	1,562	1,715	1,876
Extraprovincial	849	824	813	849	1,128	1,202	1,213	1,204	1,215	1,221
Other	17	18	18	18	19	19	19	20	20	21
Total Revenue	3,108	3,206	3,327	3,499	3,921	4,147	4,319	4,479	4,667	4,859
EXPENSES										
Operating and Administrative	703	717	730	761	773	788	804	817	832	849
Finance Expense	1,069	1,075	1,067	1,170	1,390	1,569	1,534	1,492	1,497	1,430
Depreciation and Amortization	559	558	561	600	668	721	724	732	758	766
Water Rentals and Assessments	129	128	128	134	148	152	152	152	153	154
Fuel and Power Purchased	243	253	265	245	237	249	259	269	277	288
Capital and Other Taxes	166	174	181	187	190	192	195	197	201	202
Corporate Allocation	8	8	8	8	8	8	8	8	7	7
Total Expenses	2,877	2,913	2,941	3,106	3,415	3,679	3,677	3,666	3,726	3,696
Non-Controlling Interest	3	7	9	5	7	9	11	14	16	18
Net Income	229	287	378	388	499	459	631	799	924	1,144
Additional General Consumers Revenue Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative General Consumers Revenue Percent Increase	46.64%	52.43%	58.45%	64.70%	71.20%	77.96%	84.98%	92.28%	99.87%	107.76%
Debt Ratio	89	89	88	87	85	84	82	80	77	73
Interest Coverage Ratio	1.16	1.19	1.24	1.24	1.31	1.29	1.40	1.51	1.60	1.79
Capital Coverage Ratio	1.63	1.72	1.91	2.10	2.76	2.45	2.56	2.72	2.83	3.74

Development Plan NFAT PDP (14) - 1 FOOT INCREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	15,374	16,435	17,107	18,261	18,821	22,519	22,947	25,701	29,723	30,257
Accumulated Depreciation	(5,173)	(5,536)	(5,856)	(6,223)	(6,612)	(7,028)	(7,482)	(7,938)	(8,450)	(8,997)
Net Plant in Service	10,201	10,900	11,251	12,038	12,209	15,492	15,465	17,762	21,273	21,259
Construction in Progress	2,105	2,866	4,164	5,048	6,617	5,069	6,411	5,209	2,873	4,555
Current and Other Assets	1,869	1,735	1,391	1,579	1,790	2,029	1,844	1,967	2,032	1,696
Goodwill and Intangible Assets	180	165	151	136	126	116	140	147	231	224
Regulated Assets	231	225	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	14,587	15,890	16,957	18,802	20,742	22,707	23,860	25,086	26,409	27,735
LIABILITIES AND EQUITY										
Long Term Debt	9,289	11,260	12,602	14,474	16,171	17,743	19,438	20,405	21,528	23,078
Current and Other Liabilities	2,231	1,503	1,848	1,774	1,975	2,335	1,848	2,074	2,203	1,874
Contributions in Aid of Construction	325	334	339	344	348	358	364	371	378	385
Retained Earnings	2,442	2,505	2,310	2,399	2,481	2,535	2,493	2,540	2,627	2,752
Accumulated Other Comprehensive Income	299	287	(142)	(189)	(233)	(265)	(283)	(304)	(326)	(354)
Total Liabilities and Equity	14,587	15,890	16,957	18,802	20,742	22,707	23,860	25,086	26,409	27,735

Development Plan NFAT PDP (14) - 1 FOOT INCREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	30,788	31,353	32,042	37,329	42,227	43,649	44,393	44,951	46,932	47,662
Accumulated Depreciation	(9,552)	(10,107)	(10,666)	(11,264)	(11,930)	(12,650)	(13,373)	(14,103)	(14,861)	(15,626)
Net Plant in Service	21,237	21,246	21,376	26,065	30,297	30,999	31,021	30,848	32,072	32,035
Construction in Progress	6,192	7,589	8,716	5,044	1,293	744	1,075	1,515	472	545
Current and Other Assets	1,781	2,081	2,328	2,167	2,453	2,848	3,082	3,383	3,438	4,552
Goodwill and Intangible Assets	218	214	210	207	203	199	196	192	188	185
Regulated Assets	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Assets	29,429	31,130	32,630	33,482	34,246	34,790	35,374	35,937	36,171	37,317
LIABILITIES AND EQUITY										
Long Term Debt	24,881	26,283	27,036	27,838	28,040	28,181	27,932	27,235	27,224	26,997
Current and Other Liabilities	1,546	1,551	1,912	1,566	1,622	1,559	1,752	2,205	1,517	1,737
Contributions in Aid of Construction	392	400	407	415	422	430	438	446	455	463
Retained Earnings	2,981	3,267	3,645	4,033	4,532	4,991	5,622	6,421	7,345	8,489
Accumulated Other Comprehensive Income	(371)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)
Total Liabilities and Equity	29,429	31,130	32,630	33,482	34,246	34,790	35,374	35,937	36,171	37,317

Development Plan NFAT PDP (14) - 1 FOOT INCREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,692	1,768	1,839	1,954	2,047	2,165	2,250	2,376	2,764	2,977
Cash Paid to Suppliers and Employees	(782)	(822)	(902)	(935)	(966)	(1,005)	(1,029)	(1,053)	(1,135)	(1,171)
Interest Paid	(466)	(474)	(510)	(554)	(601)	(699)	(814)	(818)	(1,032)	(1,122)
Interest Received	28	17	24	26	31	39	41	38	35	33
Cash from Operating Activities	473	488	451	490	512	500	448	543	633	716
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	836	2,170	1,560	2,190	2,180	2,380	1,990	1,590	1,790	1,990
Sinking Fund Withdrawals	129	393	102	26	-	15	416	183	265	676
Retirement of Long Term Debt	(119)	(808)	(176)	(312)	(347)	(530)	(829)	(306)	(635)	(679)
Other Financing Activities	(42)	(7)	(16)	(18)	(16)	(12)	(24)	(13)	(34)	(9)
Cash from Financing Activities	804	1,748	1,470	1,885	1,817	1,852	1,554	1,454	1,385	1,977
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(1,378)	(1,913)	(2,010)	(2,041)	(2,124)	(2,023)	(1,791)	(1,635)	(1,865)	(2,199)
Sinking Fund Payment	(107)	(208)	(124)	(188)	(165)	(227)	(216)	(220)	(248)	(338)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)
Cash from Investing Activities	(1,502)	(2,138)	(2,155)	(2,249)	(2,321)	(2,292)	(2,035)	(1,883)	(2,146)	(2,575)
Net Increase (Decrease) in Cash	(225)	99	(233)	127	8	60	(33)	114	(128)	118
Cash at Beginning of Year	43	(183)	(84)	(317)	(190)	(182)	(122)	(155)	(41)	(169)
Cash at End of Year	(183)	(84)	(317)	(190)	(182)	(122)	(155)	(41)	(169)	(51)

Development Plan NFAT PDP (14) - 1 FOOT INCREASE IN LWR OPERATING RANGE SCENARIO
Development Plan Scenario REFERENCE

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,108	3,206	3,327	3,499	3,921	4,147	4,319	4,479	4,667	4,859
Cash Paid to Suppliers and Employees	(1,200)	(1,228)	(1,258)	(1,278)	(1,297)	(1,325)	(1,352)	(1,374)	(1,398)	(1,423)
Interest Paid	(1,092)	(1,081)	(1,087)	(1,206)	(1,428)	(1,623)	(1,609)	(1,572)	(1,592)	(1,501)
Interest Received	17	19	28	33	40	55	70	78	88	69
Cash from Operating Activities	834	916	1,011	1,048	1,236	1,254	1,428	1,611	1,764	2,003
FINANCING ACTIVITIES										
Proceeds from Long Term Debt	1,760	1,390	1,190	790	190	190	(10)	(40)	(10)	(10)
Sinking Fund Withdrawals	156	-	-	450	-	-	60	250	700	13
Retirement of Long Term Debt	(432)	-	-	(450)	-	-	(60)	(220)	(700)	(13)
Other Financing Activities	(1)	(1)	(1)	(1)	(1)	(9)	(8)	(8)	(7)	(26)
Cash from Financing Activities	1,483	1,389	1,189	789	189	181	(18)	(18)	(17)	(36)
INVESTING ACTIVITIES										
Property Plant and Equipment net of contributions	(2,151)	(1,943)	(1,798)	(1,596)	(1,129)	(853)	(1,056)	(977)	(919)	(781)
Sinking Fund Payment	(244)	(262)	(287)	(309)	(307)	(322)	(336)	(347)	(348)	(326)
Other Investing Activities	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)
Cash from Investing Activities	(2,424)	(2,237)	(2,109)	(1,930)	(1,464)	(1,201)	(1,418)	(1,350)	(1,293)	(1,133)
Net Increase (Decrease) in Cash	(108)	68	91	(94)	(39)	233	(8)	243	454	834
Cash at Beginning of Year	(51)	(159)	(90)	0	(93)	(132)	102	94	337	791
Cash at End of Year	(159)	(90)	0	(93)	(132)	102	94	337	791	1,624

Section:		Page No.:	
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	License Renewal Alternatives		
Issue:	Cost/Benefit Implications		

PREAMBLE TO IR (IF ANY):

MH has suggested three alternatives for the LWR operation license. These are:

- Maintain the existing 711-715 foot operation range, and maximize JenPeg spillway and power house flows when Lake Winnipeg levels exceed 715 feet.
- Reduce operating range to 711-714 feet, maximizing Jenpeg spillway and power house flows when Lake Winnipeg levels exceed 714 feet.
- Raise the operating range to 711-716 feet, maximizing spillway and power house flows when Lake Winnipeg levels exceed 716 feet

QUESTION:

Provide MH/CEC Appendix 11 to illustrate the lost revenue related to operating range changes and quantify the IFF14 (20 year) export revenue losses/F&PP cost increases.

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH's revenue requirement.

RESPONSE:

Manitoba Hydro is not seeking any change to the license nor did it suggest alternatives to the license.

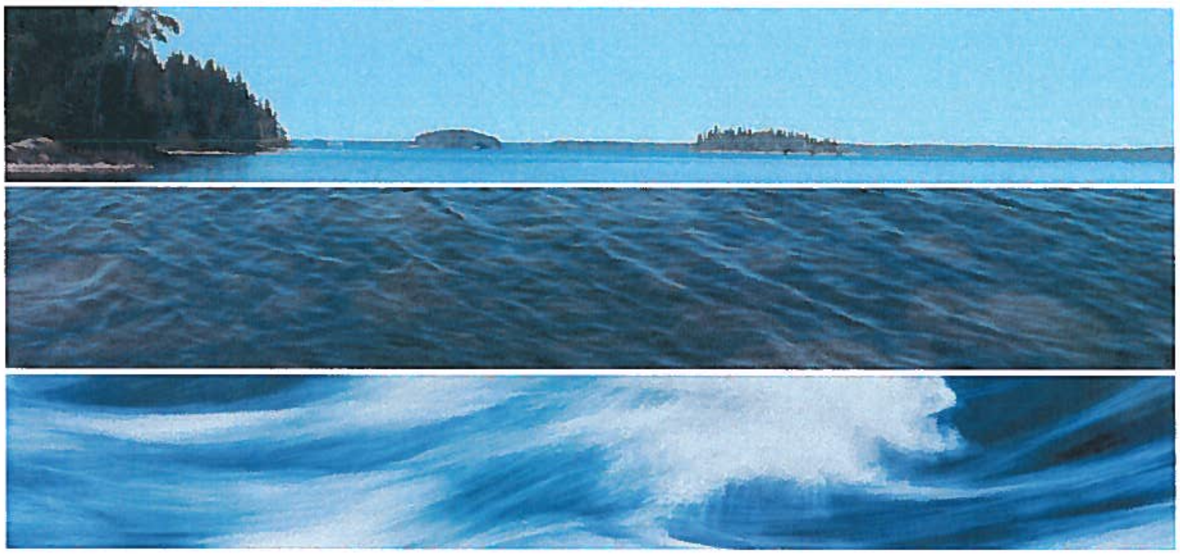
As part of the Clean Environment Commission review of LWR, the CEC requested the following from Manitoba Hydro:

> *"Based on the principles cited in a letter of 2000 02 25 from Bob Brennan to Dave Farlinger of the Lake Winnipeg Shoreline Erosion Advisory Group*

Steering Committee what would be the economic impact for Hydro holding the maximum lake level at 714, 714½ , 715, 715½ and 716 ASL."

To respond to this request, Manitoba Hydro prepared the economic evaluation summarized in Appendix 11 to Manitoba Hydro's July 2014 LWR document, which has been attached to this response.

Appendix 11



Lake Winnipeg Regulation

Manitoba Hydro

D1910

MANITOBA HYDRO
INTEROFFICE MEMORANDUM

FROM		TO	
	Terry Miles Manager Resource Planning & Market Analysis Power Planning Division		Wes Penner Manager Hydraulic Operations Power Sales & Operations Division

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DATE 2014 07 16

FILE

SUBJECT **LAKE WINNIPEG REGULATION - ECONOMIC EVALUATION**

The economic value of a 1-foot change to the Lake Winnipeg Regulation (LWR) operating range has been updated using planning assumptions from the 2012 NFAT analysis.

This economic analysis updates the work that was referred to in the letter to the Lake Winnipeg Shoreline Advisory Group dated February 25, 2000.

The economic assessments are based on the following changes to the LWR operating range with respect to the current operating levels:

1-Foot Decrease in the LWR Operating Range

The present value of the lost revenue associated with a 1-foot reduction in the LWR operating range is approximately $440 million (2014 constant Canadian dollars).

The reduced LWR operating range results in less capability for the reservoir to augment low inflows and to effectively regulate high inflows.

Under the lowest historic inflows, the reduced LWR operating range results in lower dependable energy which requires the advancement of gas-fired thermal generation and/or a reduction in the long-term export sales. Under higher inflows, a decrease in the LWR operating range results in reduced operating flexibility for the reservoir. This causes an overall reduction in the value of export sales and increases energy spillage. In addition, the dispatch of non-hydraulic energy increases, which increases operating costs.

1-Foot Increase in the LWR Operating Range

The present value of the revenue gains associated with a 1-foot increase in the LWR operating range is approximately equal to $360 million (2014 constant Canadian dollars).

The increased LWR operating range results in greater capability for the reservoir to augment low inflows and to effectively regulate high inflows.

Under the lowest historic inflows, the increased LWR operating range results in additional dependable energy which may be used to defer the in-service date for gas-fired thermal generation and/or an increase in the long-term export sales. Under higher inflows, an increase in the LWR operating range results in greater operating flexibility for the reservoir. This causes an overall increase in the value of export sales and reduces energy spillage. In addition, the dispatch of non-hydraulic energy decreases, which reduces operating costs.

It is noted that the above estimates of the impact of the change in LWR operating ranges includes the economic impacts only. It does not include any costs to mitigate adverse affects to any stakeholders.

Section:		Page No.:	
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	License Renewal Alternatives		
Issue:	Cost/Benefit Implications		

PREAMBLE TO IR (IF ANY):

MH has suggested three alternatives for the LWR operation license. These are:

- Maintain the existing 711-715 foot operation range, and maximize JenPeg spillway and power house flows when Lake Winnipeg levels exceed 715 feet.
- Reduce operating range to 711-714 feet, maximizing Jenpeg spillway and power house flows when Lake Winnipeg levels exceed 714 feet.
- Raise the operating range to 711-716 feet, maximizing spillway and power house flows when Lake Winnipeg levels exceed 716 feet

QUESTION:

Provide MH/CEC Appendix 12 to illustrate the status of Lake Winnipeg shoreline erosion mitigation measures and quantify the magnitude of and impacts under each scenario.

RATIONALE FOR QUESTION:

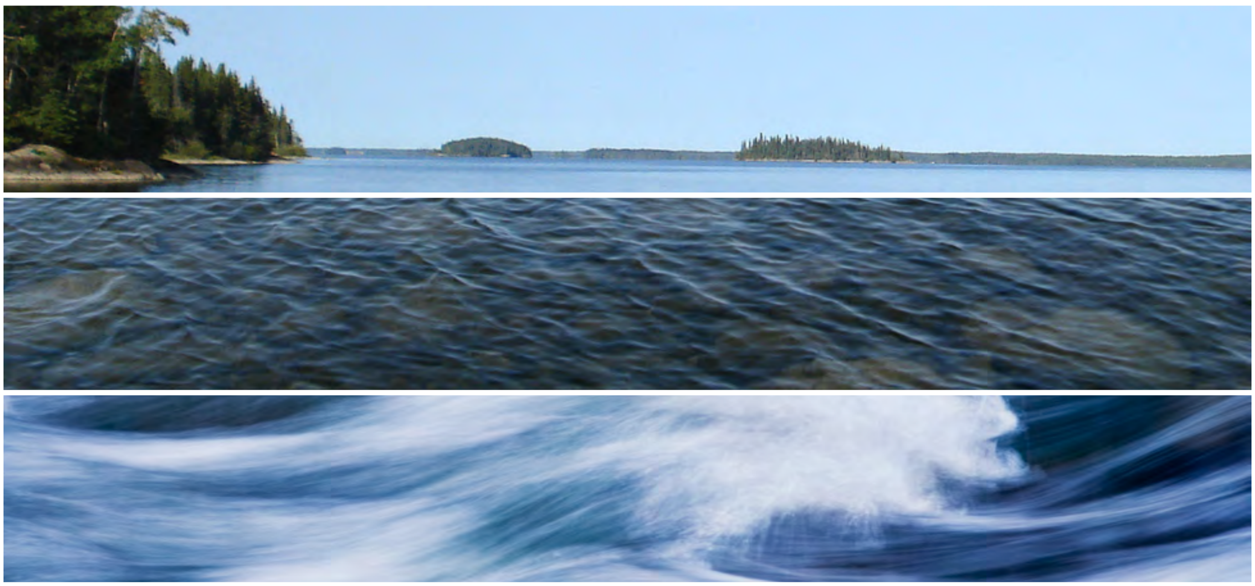
To understand the possible impact of changes to LWR on MH's revenue requirement.

RESPONSE:

Manitoba Hydro is not seeking any change to the license nor did it suggest alternatives to the license.

Please see the attachment to this response.

Appendix 12



Lake Winnipeg Regulation

Manitoba Hydro

LWR CEC Submission – Appendix 12

Shoreline erosion on Lake Winnipeg is described in Section 4.3 of the main document. In response to the Clean Environment Commission's request, the following provides more information on the Lake Winnipeg Shoreline Erosion Advisory Group, the Lake Winnipeg Stewardship Board, and the Shoreline Erosion Technical Committee.

Lake Winnipeg Shoreline Erosion Advisory Group

In response to ongoing concerns voiced by Lake Winnipeg stakeholders, the province of Manitoba established the *Lake Winnipeg Shoreline Erosion Advisory Group* (LWSEAG) in 1998 to review specific issues related to erosion of Lake Winnipeg's shorelines.

The LWSEAG membership consisted of officials from municipalities along the lake's south basin, First Nations, the Manitoba Métis Federation, Lake Winnipeg property owners and professional engineers with expertise in hydrology and erosion.

The purpose of the LWSEAG was to:

- Gather and disseminate information on erosion processes and practical shoreline protection options;
- Assist the Province in initiating a third party assessment of the accuracy and integrity of Manitoba Hydro's reporting of Lake Winnipeg water level data and methodology;
- Receive and respond to public concerns and questions regarding erosion; and
- Advise the Province and stakeholders on matters regarding erosion.

To fulfil its mandate, the LWSEAG met regularly over a period of about 18 months, toured erosion sites and beaches in the south basin of Lake Winnipeg, held public meetings to identify public concerns, received presentations from Crown corporations and government agencies and commissioned studies on technical matters.

The LWSEAG retained Baird and Associates to review the Lake Winnipeg water level reporting procedures and Pollock and Wright to confirm the benchmarks used to set the water level gauges.

> "As a result of the Baird and Associates and the Pollock and Wright reports, the Advisory Group is satisfied that the Lake Winnipeg wind-eliminated water levels determined and reported by Manitoba Hydro are reasonably accurate." (LWSEAG, 2000)

The LWSEAG retained Linnet to estimate the extent of erosion over time using aerial photography at seven areas around the south basin of Lake Winnipeg: Hnausa, Spruce Sands, Matlock, Winnipeg Lake South Ridge, Halcyon, Lester, and Traverse Bay.

> "The general conclusion is that the lake shoreline is dynamic with active deposition and erosion occurring as part of the normal life cycle of the beach."(Linnet, 2000)

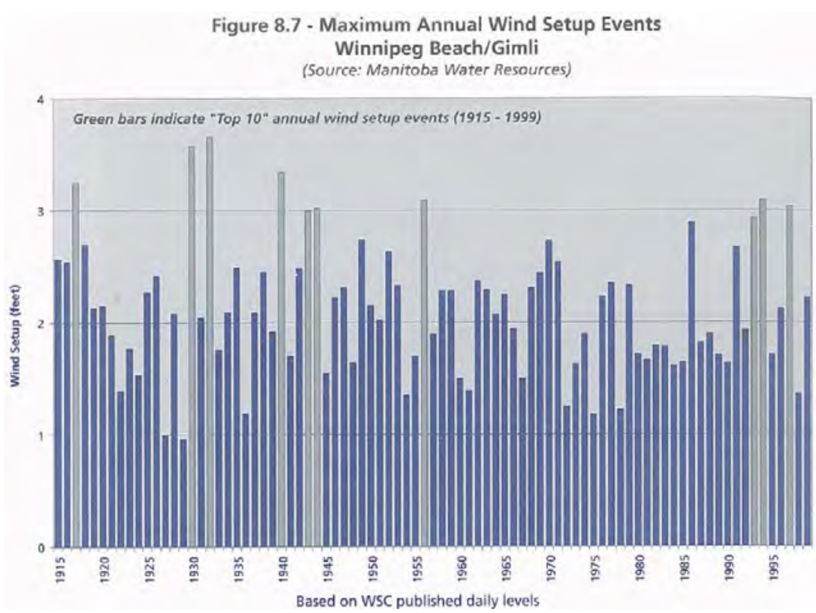
The shoreline regulatory environment was found to be a very complicated issue. A number of questions were forwarded to Manitoba Justice and the law firm Aikins, McAulay, and Thorvaldson by the LWSEAG in developing a response to this question.

> "Generally, responsibility for the wise management of shoreline seems to lie with a combination of private landowners, municipal governments, and the Province. The role of each will depend on the specific circumstances of the land in question, and will depend largely on how the land was originally granted and on what caveats or conditions may have been placed on the titles over time" (LWSEAG, 2000)

The LWSEAG also retained Baird and Associates and Stantec to review the erosion factors along the shoreline of the south basin of Lake Winnipeg and to identify appropriate shoreline management options for representative sites. The following conclusion from this technical report was reiterated in the LWSEAG's final report:

> "In most instances, erosion, flooding and dynamic beach changes at the shoreline are the result of naturally occurring processes. Man-made alterations to the natural lake systems may affect the extent of erosion, flooding and dynamic beach changes, but typically to a much lesser degree than the natural processes." (LWSEAG, 2000)

One of the main public concerns identified by the LWSEAG was the perception that erosion was occurring at a faster rate, particularly since 1992. In response, the LWSEAG requested information the Water Resources Branch of Manitoba Conservation who indicated that "Three of the ten largest wind set-up events since 1915 occurred between 1993 and 1997." and that "The frequency of occurrence of major wind setup events doubled in the period 1992-1999 as compared to the period 1974-1991." (LWSEAG, 2000) It was also reported that Lake Winnipeg water levels were about 0.4 ft above the long-term average during this period because of above average inflows.



Source: LWSEAG Final Report, 2000

The most significant recommendations made by the LWSEAG include:

• "The Advisory Group recommends the establishment of an ongoing advisory board that would provide a basin-wide forum to review and consider management issues related to erosion and environmental quality of the lake. This board would have representation from, and work closely with government, Manitoba Hydro, local municipalities, aboriginal communities, technical specialists, the public and local interest groups.

• It is recommended that regulations and/or legislation be enacted to control the design and placement of structures on Lake Winnipeg shorelines, that shoreline protection demonstration projects be carried out, and that there should be a long-term commitment to provide technical advisory services to municipalities and property owners.

• With respect to shoreline protection options, it is recommended that whenever possible, nonstructural solutions to erosion problems be adopted. The Shoreline Protection Handbook prepared as part of this study contains specific recommendations and guidelines for shoreline protection options for different shoreline types." (LWSEAG, 2000)

The Province of Manitoba distributed the Lake Winnipeg Shoreline Management Handbook in March of 2001. The Handbook can be found online at:

http://www.hydro.mb.ca/corporate/water_regimes/lake_wpg_regulation/lake_wpg_regulation_cec_submission.shtml

Lake Winnipeg Stewardship Board

The government of Manitoba established the *Lake Winnipeg Stewardship Board* (LWSB) in February 2003 as one of six actions under the Lake Winnipeg Action Plan. The role of the board was originally to assist the government of Manitoba in reducing phosphorus and nitrogen in the lake to pre-1970 levels. The mandate of the board was expanded in 2007 to focus on water quality and the health of the lake and to follow through/report on actions taken from recommendations from the initial board report. Board membership includes a variety of interests such as fishing, agriculture, urban land use, First Nations, federal, provincial and municipal government, and non-government organizations.

In 2006, the LWSB prepared a report for the Minister of Water Stewardship where they made recommendations aimed at protecting the health of Lake Winnipeg and its watershed. The following is recommendation 12.7:

> "The Province of Manitoba should consider establishing regulations, such as minimum set back distances from shorelines for new developments, to prevent significant disturbances which would result in increased erosion along lakes and waterways." (LWSB, 2006)

In 2009, the LWSB reported on the progress made in implementing its 2006 recommendations. In regards to recommendation 12.7, the following progress was reported:

> • "The Nutrient Management Regulation established under The Water Protection Act sets out nutrient buffer zones where nutrients cannot be applied within specified distances from the high water mark of Manitoba's streams, rivers and lakes, and restricts certain types of developments within such zones.
>
> • Clause 4(1) of The Manitoba Crown Lands Act reserves to the Crown 1.5 chains (30 metres) from the ordinary high water mark out of every disposition or sale of Crown land. Consequently, when Crown lands are sold or leased to private owners, a setback is established of 30 metres within which development cannot occur.
>
> • In general, all development plans established under Provincial legislation and related municipal zoning by-laws provide minimum set-back distances from shorelines for new developments to prevent significant disturbances which would result in increased erosion along lakes and waterways.
>
> • Additionally, Manitoba Water Stewardship reviews all development proposals and subdivision applications to ensure that required minimum setbacks are included." (LWSB, 2009)

The LWSB's term ended in January 2010.

The Shoreline Erosion Technical Committee

The Shoreline Erosion Technical Committee (SETC) was originally established as a technical advisory board on best practices for preventing and repairing shoreline erosion on Lake Winnipeg. The mandate of the SETC has recently expanded to be province wide. The SETC is a multi-disciplinary committee composed of representatives from local, provincial, and federal governments that includes expertise in fisheries, conservation, water stewardship, engineering, and land surveying.

Applications for shoreline protection works can be forwarded to the SETC from the local planning district or development permitting authority. The SETC then provides suggestions towards the design and construction of shoreline protection works and riverbank stabilization measures. In the past, the Department of Fisheries and Oceans (DFO) has partnered with the SETC and provided comments on site specific reviews through the SETC's response to the application. This coordinated application process eliminated the need for a separate application to DFO.

Section:		Page No.:	
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	License Renewal Alternatives		
Issue:	Cost/Benefit Implications		

PREAMBLE TO IR (IF ANY):

MH has suggested three alternatives for the LWR operation license. These are:

- Maintain the existing 711-715 foot operation range, and maximize JenPeg spillway and power house flows when Lake Winnipeg levels exceed 715 feet.
- Reduce operating range to 711-714 feet, maximizing Jenpeg spillway and power house flows when Lake Winnipeg levels exceed 714 feet.
- Raise the operating range to 711-716 feet, maximizing spillway and power house flows when Lake Winnipeg levels exceed 716 feet

QUESTION:

Explain and quantify MH's Northern Flood Agreement mitigation payments that relate to Nelson River flows under each scenario.

RATIONALE FOR QUESTION:

To understand the possible impact of changes to LWR on MH's revenue requirement.

RESPONSE:

Manitoba Hydro is not seeking any change to the license nor did it suggest alternatives to the license.

Manitoba Hydro has not assessed the potential for financial impacts associated with the Northern Flood Agreement ("NFA") or any other Settlement Agreement that might be associated with a change to the power range on Lake Winnipeg.

The 711-715 range corresponds to the power production range in the existing LWR interim license (status quo). Manitoba Hydro's forecast of NFA and other mitigation payments under this licence are included in MH14. The responses to PUB/MH-I-24d and PUB/MH-I-65d and PUB/MH-I-65e provide the value of the mitigation obligation and the revenue requirement impacts included in MH14.

Section:	Tab 9 & Tab 11	**Page No.:**	Appendix 11.19 pg. 3
Topic:	Export Revenues		
Subtopic:	Firm & Opportunity Sales		
Issue:	Unit export revenues (actual and IFF14)		

PREAMBLE TO IR (IF ANY):

MH's export market revenues appear to correlate with the variable cost of operating an efficient CCCT natural gas plant. Natural gas prices have been in decline.

QUESTION:

Provide an updated version of the attached NFAT PUB/MH I-105 (a) Revised to include 2013/14 and 2014/15 actual data; also forecast natural gas prices for 2015/16 and 2016/17.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; 2012 GRA – PUB/MH II-9 b)

QUESTION:

Please re-file table extending data from 2008/09 to 2012/13.

RESPONSE:

Following the informal meeting between Manitoba Hydro staff and PUB Advisors contemplated in Order 119/13, the PUB Advisors required this Information Request to be revised and the following information provided:

	Henry Hub Natural Monthly Gas Price Range (US$/ MMBTU) [Note 1]	Average Annual Henry Hub Gas Price (US$/ MMBTU) [Note 1]	Range of Efficient CCCT Variable Costs (US$/ MWh) [Note 2]	Efficient CCCT Variable Costs based on Average Annual Gas Price (US$/ MWh) [Note 2]	Physical Day Ahead Opportunity Market Avg Price	Opportunity Exports: On Peak Avg Price	Opportunity Exports: Off Peak Avg Price
2008/09	3.96 to 12.69	7.84	36.7 to 102	65.8	3.4 ¢/kWh	71.78 CAD$/ MWh (7.2 ¢/kWh)	29.37 CAD$/ MWh (2.9 ¢/kWh)
2009/10	2.99 to 5.83	4.09	29.4 to 50.7	37.7	2.2 ¢/kWh	31.14 CAD$/ MWh (3.1 ¢/kWh)	18.74 CAD$/ MWh (1.8 ¢/kWh)
2010/11	3.43 to 4.8	4.15	32.7 to 43	38.1	2.3 ¢/kWh	31.90 CAD$/ MWh (3.2 ¢/kWh)	21.23 CAD$/ MWh (2.1 ¢/kWh)
2011/12	2.17 to 4.54	3.57	23.3 to 41.0	33.8	2.1 ¢/kWh	28.76 CAD$/ MWh (2.9 ¢/kWh)	22.51 CAD$/ MWh (2.3 ¢/kWh)
2012/13	1.95 to 3.81	3.01	21.6 to 35.6	29.6	2.2 ¢/kWh	29.87 CAD$/ MWh (3.0 ¢/kWh)	22.02 CAD$/ MWh (2.2 ¢/kWh)

RATIONALE FOR QUESTION:

To compare and assess the reasonableness of MH's historic export unit revenue prices with the forecast 75% increase in unit revenues by 2019/20.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH-I-15c which provides both historic and projected average unit revenues and describes factors affecting increases in average unit revenue over time.

The table below updates the data provided in NFAT PUB/MH I-015a.

It should be noted that the day-ahead energy market price in any interval is based on the variable cost of the marginal generation unit, which generally is a coal, natural gas combined cycle or single cycle natural gas generating unit, subject to transmission constraints.

Day-ahead opportunity energy sales are only one component of market revenue streams available to Manitoba Hydro. A significant portion of Manitoba Hydro's export revenues is from long term bilateral sales which include the value of generation capacity and the value to the customer of a long term supply from a renewable hydro resource.

Year	Henry Hub Natural Gas Monthly Gas Price Range (US$/MMBTU) Note 1	Average Annual Henry Hub Gas Price (US$/MMBTU) Note 1	Range of Efficient CCGT Variable Costs (US$/MWh) Note 2	Efficient CCCT Variable Costs based on Average Annual Gas Price (US$/MWh) Note 2	Physical Day Ahead Opportunity Market Avg Price	Opportunity Exports On-Peak Avg Price	Opportunity Export Off Peak Avg Price
2008/09	3.96 to 12.69	7.84	36.7 to 102	65.8	3.4¢/kWh	71.78 CAD$/MWh (7.2¢/kWh)	29.37 CAD$/MWh (2.9¢/kWh)
2009/10	2.99 to 5.83	4.09	29.4 to 50.7	37.7	2.2¢/kWh	31.14 CAD$/MWh (3.1¢/kWh)	18.74 CAD$/MWh (1.9¢/kWh)
2010/11	3.43 to 4.8	4.15	32.7 to 43	38.1	2.3¢/kWh	31.90 CAD$/MWh (3.2¢/kWh)	21.23 CAD$/MWh (2.1¢/kWh)
2011/12	2.17 to 4.54	3.57	23.3 to 41.0	33.8	2.1¢/kWh	28.76 CAD$/MWh (2.9¢/kWh)	22.51 CAD$/MWh (2.3¢/kWh)
2012/13	1.95 to 3.81	3.01	21.6 to 35.6	29.6	2.2¢/kWh	29.87 CAD$/MWh (3.0¢/kWh)	22.02 CAD$/MWh (2.2¢/kWh)
2013/14	3.43 to 6.01	4.16	32.7 to 52.08	38.2	3.4¢/kWh	43.64 CAD$/MWh (4.4¢/kWh)	26.33 CAD$/MWh (2.6¢/kWh)
2014/15 Note 3	3.00 to 4.63	4.01	29.5 to 41.73	37.1	2.9¢/kWh	35.68 CAD$/MWh (3.6¢/kWh)	22.85 CAD$/MWh (2.3¢/kWh)

Note 1 - Henry Hub Gulf Coast Monthly Natural Gas Prices are a monthly average of daily spot prices (in US$/MMBTU) from the US DOE EIA. Annual prices are an average of the 12 monthly averages for the fiscal year.

Note 2 - Efficient CCCT Variable Costs are in US$/MWh. Assumption of a heat rate of 7,500 MMBTU/MWh and a $7.00/MWh variable O&M are consistent with the assumptions in the illustrative example provided in Exhibit #MH-16 from the 2010 GRA.

Note 3 - To end of January 2015

In regards to the short term natural gas forecast, in February of 2015 the US Department of Energy (DOE) Energy Information Administration (EIA) released their Short Term Energy Outlook which provides a monthly natural gas forecast until December 2016. Due to the recent release of this forecast, it takes into account the commodity spot and futures price declines that occurred in late 2014 for both oil and natural gas.

Year	Henry Hub Monthly Average Forecasted Price Range (US$/MMBTU)	Average Forecasted Annual Henry Hub Gas Price (US$/MMBTU)
2015	2.79 to 3.41	3.05
2016	3.25 to 3.69	3.47

The EIA's Short Term Energy Forecast is available at: http://www.eia.gov/forecasts/steo/report/natgas.cfm. Reference case forecasts for the EIA's long term forecast, the 2015 Annual Energy Outlook, will not be available until March 2015.

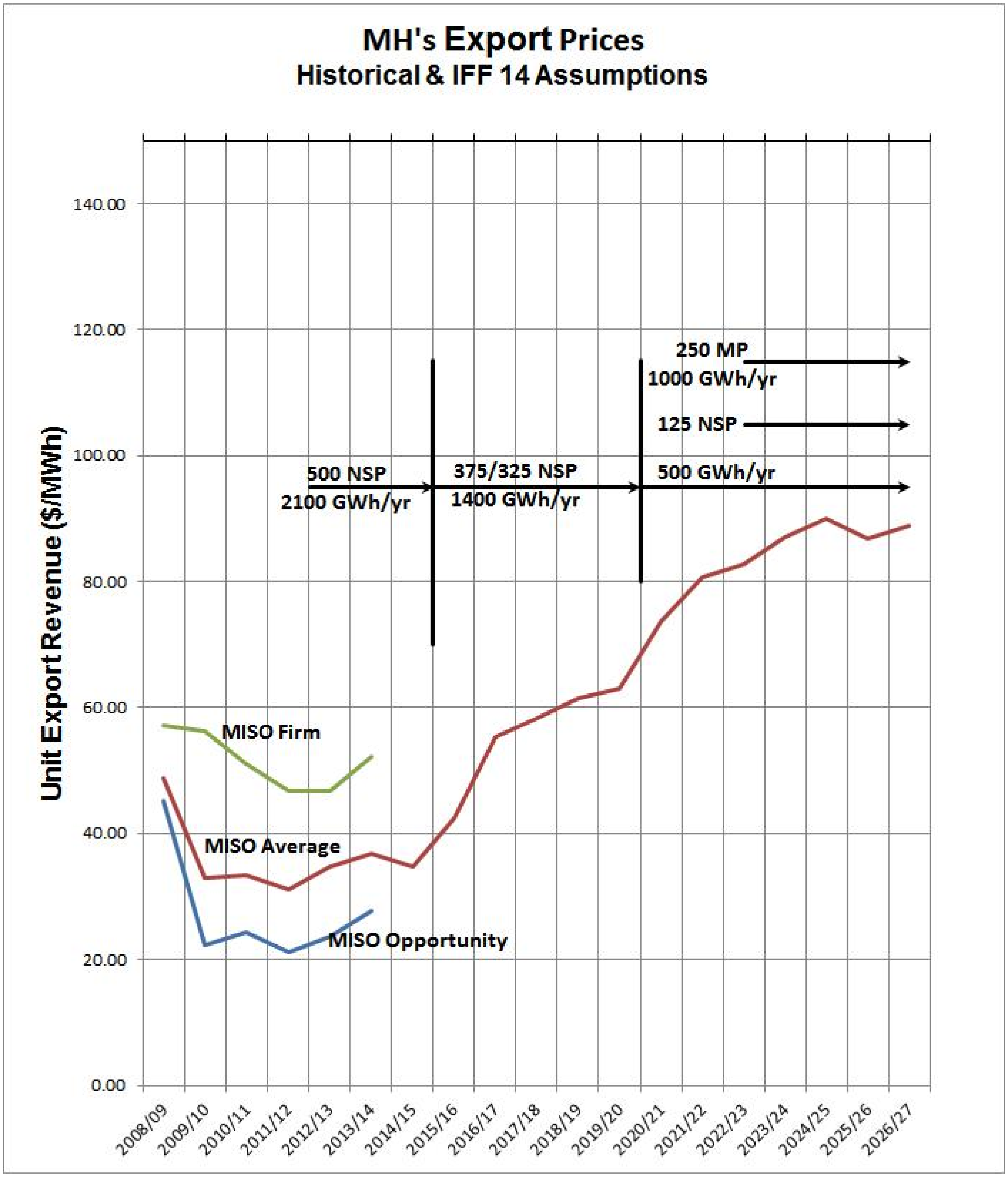
Section:	Tab 9 & Tab 11	Page No.:	Appendix 11.19 pg. 3
Topic:	Export Revenues		
Subtopic:	Firm & Opportunity Sales		
Issue:	Unit export revenues (actual and IFF14)		

PREAMBLE TO IR (IF ANY):

MH's export market revenues appear to correlate with the variable cost of operating an efficient CCCT natural gas plant. Natural gas prices have been in decline.

QUESTION:

Provide a graphical illustration of MH's actual 2008/09 to 2014/15 MISO firm and MISO opportunity average prices (see attached example) and MH IFF-14 average unit revenues out to 2034/35.


MH's Export Prices
Historical & IFF 14 Assumptions
Unit Export Revenue ($/MWh)
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
250 MP
1000 GWh/yr
125 NSP
500 NSP
2100 GWh/yr
375/325 NSP
1400 GWh/yr
500 GWh/yr
MISO Firm
MISO Average
MISO Opportunity
2008/09
2009/10
2010/11
2011/12
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27

RATIONALE FOR QUESTION:

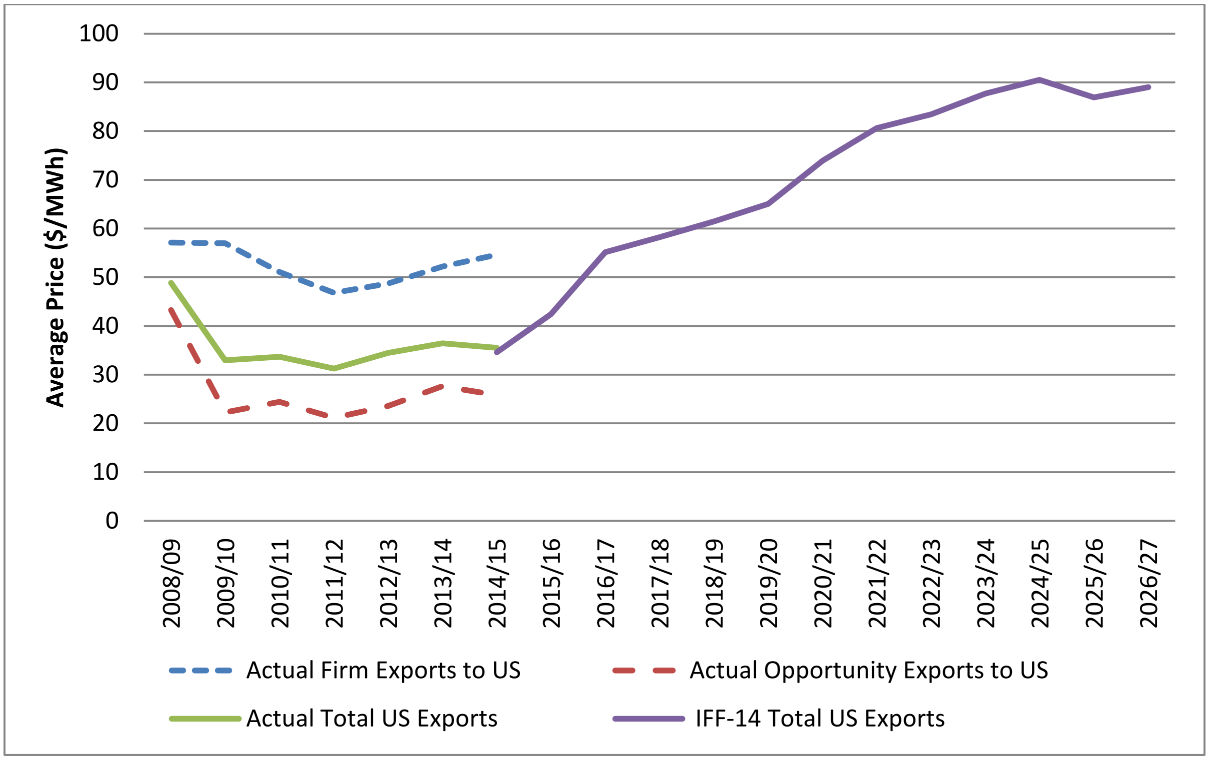
To compare and assess the reasonableness of MH's historic export unit revenue prices with the forecast 75% increase in unit revenues by 2019/20.

RESPONSE:

Please see Figure 1 below. Note that data labels have been modified from those used in the question because the average prices shown on the chart are for firm U.S. exports and opportunity U.S. exports; these include both bilateral and MISO market transactions. Similarly, future US unit revenues include bilateral sales with US customers as well as MISO market transactions. Also note that the actual average prices used for 2014/15 only represent the period of Apr to Dec 2014 and therefore are not an accurate reflection of the complete fiscal year.

As explained in Section 9.5 of the application, realized average opportunity prices are affected by water supply conditions. Water conditions have been well above average in recent history resulting in significant volumes of off peak opportunity sales which lower overall average opportunity prices. Average unit revenues in IFF14 for 2016/17 and later years reflect firm and average (based on MH's long term flow record) opportunity sale volumes, and therefore are not comparable to the historic prices shown.

Figure 1. Average Export Prices to US and IFF14 Average Unit Revenue for US Exports.



Section:	Tab 9 & Tab 11	Page No.:	Appendix 11.19 pg. 3
Topic:	Export Revenues		
Subtopic:	Firm & Opportunity Sales		
Issue:	Unit export revenues (actual and IFF14)		

PREAMBLE TO IR (IF ANY):

MH's export market revenues appear to correlate with the variable cost of operating an efficient CCCT natural gas plant. Natural gas prices have been in decline.

QUESTION:

Provide a detailed tabulation of MH's Firm contract sales by counterparty (MW and GWH) for the years 2014/15 to 2034/35.

RATIONALE FOR QUESTION:

To compare and assess the reasonableness of MH's historic export unit revenue prices with the forecast 75% increase in unit revenues by 2019/20.

RESPONSE:

The information requested is commercially sensitive and has been filed in confidence with the PUB.

Section:	Appendix 11.20 Appendix 11.21 Appendix 11.22	Page No.:	pp.1 -13 p.2 p.1
Topic:	Export Revenues		
Subtopic:	Opportunity Sales		
Issue:	Opportunity Sales in Sept/Oct		

PREAMBLE TO IR (IF ANY):

Appendix 11.20 shows the following opportunity sales and imports:

	MISO Opportunity Sales Sept/Oct	MISO Imports Winter Purchases
2008/09	1500 GWh @ 3.0 ¢/kWh	120 GWh @ 4.0 ¢/kWh
2009/10	1600 GWh @ 2.0 ¢/kWh	220 GWh @ 2.5 ¢kWh
2010/11	1450 GWh @ 2.1 ¢/kWh	60 GWh @ 2.8 ¢/kWh
2011/12	1000 GWh @ 2.0 ¢/kWh	260 GWh @ 1.6 ¢/kWh
2012/13	1100 GWh @ 2.2 ¢/kWh	350 GWh @ 5.8 ¢/kWh
2013/14	1400 GWh @ 2.5 ¢/kWh	460 GWh @ 4.3 ¢/kWh

QUESTION:

For 2013/14, confirm that MH's total imports were 891 GWh (1824 minus 933) of which 460 GWh ± were from MISO market sources at about 4.3± ¢/kWh.

RATIONALE FOR QUESTION:

This question explores whether any winter imports are necessitated by summer exports.

RESPONSE:

Manitoba Hydro confirms that for 2013/14 the total physical and financial purchases (excluding wind generation) was 891 GWh.

Manitoba Hydro cannot confirm the 460 GWh nor the 4.3 ¢/kWh amounts referenced in the question. As indicated in Revised Appendix 11.20, page 14 of 14, for the 2013/14 winter season (November through March) Manitoba Hydro imported 503 GWh at $42.1/MWh or 4.21¢/kWh.

Section:	Appendix 11.20 Appendix 11.21 Appendix 11.22	Page No.:	pp.1 -13 p.2 p.1
Topic:	Export Revenues		
Subtopic:	Opportunity Sales		
Issue:	Opportunity Sales in Sept/Oct		

PREAMBLE TO IR (IF ANY):

Appendix 11.20 shows the following opportunity sales and imports:

	MISO Opportunity Sales Sept/Oct	MISO Imports Winter Purchases
2008/09	1500 GWh @ 3.0 ¢/kWh	120 GWh @ 4.0 ¢/kWh
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2010/11	1450 GWh @ 2.1 ¢/kWh	60 GWh @ 2.8 ¢/kWh
2011/12	1000 GWh @ 2.0 ¢/kWh	260 GWh @ 1.6 ¢/kWh
2012/13	1100 GWh @ 2.2 ¢/kWh	350 GWh @ 5.8 ¢/kWh
2013/14	1400 GWh @ 2.5 ¢/kWh	460 GWh @ 4.3 ¢/kWh

QUESTION:

For 2013/14 confirm that MH's Day-Ahead and Real-Time exports were priced at an average of approximately 2.8 ¢ kWh.

RATIONALE FOR QUESTION:

This question explores whether any winter imports are necessitated by summer exports.

RESPONSE:

Not confirmed. As indicated in the table provided in the revised Appendix 11.21 for 2013/14, MH's Day Ahead and Real Time exports were priced at an average of 2.7 ¢/kWh. This price is calculated as an average of energy transactions, not revenue divided by volume as revenues include adjustments for prior periods.

Section:	Appendix 11.20 Appendix 11.21 Appendix 11.22	Page No.:	pp.1 -13 p.2 p.1
Topic:	Export Revenues		
Subtopic:	Opportunity Sales		
Issue:	Opportunity Sales in Sept/Oct		

PREAMBLE TO IR (IF ANY):

Appendix 11.20 shows the following opportunity sales and imports:

	MISO Opportunity Sales Sept/Oct	MISO Imports Winter Purchases
2008/09	1500 GWh @ 3.0 ¢/kWh	120 GWh @ 4.0 ¢/kWh
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2010/11	1450 GWh @ 2.1 ¢/kWh	60 GWh @ 2.8 ¢/kWh
2011/12	1000 GWh @ 2.0 ¢/kWh	260 GWh @ 1.6 ¢/kWh
2012/13	1100 GWh @ 2.2 ¢/kWh	350 GWh @ 5.8 ¢/kWh
2013/14	1400 GWh @ 2.5 ¢/kWh	460 GWh @ 4.3 ¢/kWh

QUESTION:

Confirm that the 460 GWh of MISO winter imports in 2013/14 offset 460 GWh of MISO (7x8) off-peak summer sales that were priced at under 2 ¢/kWh in August and September of 2013, and that the winter import would not have been required had Manitoba Hydro reduced its summer exports by an equivalent amount. If this is incorrect, please explain.

RATIONALE FOR QUESTION:

This question explores whether any winter imports are necessitated by summer exports.

RESPONSE:

Not confirmed. Had Manitoba Hydro reduced its off-peak sales in the summer of 2013, more water would have been spilled as storages were already full. Avoidance of these sales would not have reduced winter 2013/14 purchases.

From late-June to mid-August, 2013 floodwaters from Alberta and northwest Ontario resulted in Lake Winnipeg levels above the upper limit of the power production range. In this circumstance Manitoba Hydro is required to maximize outflows from Lake Winnipeg. This operation forced generation at the Nelson River stations and maximum possible exports at all hours through the summer and fall of 2013.

During the winter of 2013/14 in spite of maximum outflows from Lake Winnipeg winter energy purchases were required, particularly during the record cold weather in January and February, 2014.

Manitoba Hydro’s energy operations planning objective is to plan for the secure and economic operation of its reservoirs and generating stations. Operations in the summer of 2013 and winter 2013/14 were consistent with this objective.

Section:	App. 9.1 App. 11.22	**Page No.:**	p.1 of 9 p. 1of 1
Topic:	Power Resources		
Subtopic:	Hydraulic Generation		
Issue:	Actual 2013/14 vs 2014/15		

PREAMBLE TO IR (IF ANY):

The following actual hydraulic generation values are available.

	Actual 2013/14 (GWh)		**Actual 2014/15** (GWh)	
Apr	2685		2765	
May	2903		2708	
Jun	2948		2948	
Jul	3214		3174	
Aug	3270		3203	
Sep	2705		2726	
Oct	3088		2262	
Nov	2848		2944	
Dec	3055	26715	3170	25950
Jan	2947		?	
Feb	2646		?	
Mar	2953	35261	?	?

QUESTION:

Complete and confirm the information in the above table.

RATIONALE FOR QUESTION:

This request seeks updated hydraulic generation numbers which are provided in every GRA proceeding.

RESPONSE:

	Actual 2013/14		Actual 2014/15	
	(GWh)	Total	(GWh)	Total
Apr	2685		2769	
May	2903		2714	
Jun	2948		2954	
Jul	3214		3181	
Aug	3270		3207	
Sep	2705		2731	
Oct	3088		2267	
Nov	2848		2949	
Dec	3055	26715	3177	25949
Jan	2947		3230	
Feb	2646		na	
Mar	2953	35261	na	na

Note that the table provided in the question appears to exclude Laurie River generation for 2014/15.

Section:	App. 9.1 App. 11.22	Page No.:	p.1 of 9 p. 1of 1
Topic:	Power Resources		
Subtopic:	Hydraulic Generation		
Issue:	Actual 2013/14 vs 2014/15		

PREAMBLE TO IR (IF ANY):

The following actual hydraulic generation values are available.

	Actual 2013/14 (GWh)		Actual 2014/15 (GWh)	
Apr	2685		2765	
May	2903		2708	
Jun	2948		2948	
Jul	3214		3174	
Aug	3270		3203	
Sep	2705		2726	
Oct	3088		2262	
Nov	2548		2944	
Dec	3055	26715	3170	25950
Jan	2947		?	
Feb	2646		?	
Mar	2953	35261	?	?

QUESTION:

Add a column for each year with average hydraulic generation.

RATIONALE FOR QUESTION:

This request seeks updated hydraulic generation numbers which are provided in every GRA proceeding.

RESPONSE:

Table 1. Actual Historic Hydraulic Generation (GWh).

Month	**2013/14**			**2014/15**			**Monthly Average** (of FY 2013/14 and 2014/15)	**Monthly Average** (of FY 1992/93 – 2013/14)
	Monthly	Total	Average (April 1st to date)	Monthly	Total	Average (April 1st to date)		
Apr	2685			2769			2727	2784
May	2903			2714			2809	2501
Jun	2948			2954			2951	2668
Jul	3214			3181			3198	2394
Aug	3270			3207			3239	2515
Sep	2705			2731			2718	2478
Oct	3088			2267			2677	2694
Nov	2848			2949			2899	2720
Dec	3055	26715	2698	3177	25949	2883	3116	2443
Jan	2947			3230			3088	2624
Feb	2646			?				2606
Mar	2953	35261	2939	?	?	?		2725

Note that the table included in this question appears to exclude Laurie River generation for 2014/15; this response includes Laurie River generation.

The question is unclear as to what average information is being requested, so multiple averages of actual hydraulic generation have been provided. For the longer term monthly average actual hydraulic generation, the post-Limestone period was used. Note that, in addition to inflows, other factors such as the addition of Wuskwatim G.S. affect total hydraulic generation. Please refer to MIPUG/MH-I-9 for annual total hydraulic generation and average annual hydraulic generation for FY 1992/93 through 2013/14.

Section:	App. 9.1 App. 11.22	**Page No.:**	p.1 of 9 p. 1of 1
Topic:	Power Resources		
Subtopic:	Hydraulic Generation		
Issue:	Actual 2013/14 vs 2014/15		

PREAMBLE TO IR (IF ANY):

The following actual hydraulic generation values are available.

	Actual 2013/14 (GWh)		**Actual 2014/15** (GWh)	
Apr	2685		2765	
May	2903		2708	
Jun	2948		2948	
Jul	3214		3174	
Aug	3270		3203	
Sep	2705		2726	
Oct	3088		2262	
Nov	2548		2944	
Dec	3055	26715	3170	25950
Jan	2947		?	
Feb	2646		?	
Mar	2953	35261	?	?

QUESTION:

Provide the 2014/15 Q3 & Q4 import/wind/thermal generation separately.

RATIONALE FOR QUESTION:

This request seeks updated hydraulic generation numbers which are provided in every GRA proceeding.

RESPONSE:

	Actual Results (GWh)	Thermal Generation	Wind Purchases	Imports
2014/15	Q1	4	233	28
	Q2	11	187	12
	Q3	14	278	96
	Q4	na	na	na
	Annual			

Information for the fourth quarter is not yet available, and cannot be publicly released until approximately mid-May 2015.

Section:	Tab 10	**Page No.:**	4&5
Topic:	PUB Directives and Interim Orders		
Subtopic:	Order 43/13 Directive 10		
Issue:	Risk		

PREAMBLE TO IR (IF ANY):

In Order 43/10 the Board directed:

> *"10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board."*

MH has stated that MH has engaged KPMG to satisfy this directive and this report will be available to be reviewed at the next GRA.

QUESTION:

Please file the public version of Manitoba Hydro's Corporate Risk Management Report.

RATIONALE FOR QUESTION:

To understand and quantify the risks faced by Manitoba Hydro.

RESPONSE:

Please see Appendix 11.7, Corporate Overview MFR 10 for a redacted version of Manitoba Hydro's Corporate Risk Management Report.

Section:	Tab 10	**Page No.:**	4&5
Topic:	PUB Directives and Interim Orders		
Subtopic:	Order 43/13 Directive 10		
Issue:	Risk		

PREAMBLE TO IR (IF ANY):

In Order 43/10 the Board directed:

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MH has stated that MH has engaged KPMG to satisfy this directive and this report will be available to be reviewed at the next GRA.

QUESTION:

Please file in confidence Manitoba Hydro's current full Corporate Risk Management Report

RATIONALE FOR QUESTION:

To understand and quantify the risks faced by Manitoba Hydro.

RESPONSE:

Manitoba Hydro has provided a full copy of its Corporate Risk Management Report to the PUB, in confidence.

Section:	Tab 10	Page No.:	4&5
Topic:	PUB Directives and Interim Orders		
Subtopic:	Order 43/13 Directive 10		
Issue:	Risk		

PREAMBLE TO IR (IF ANY):

In Order 43/10 the Board directed:

> *"10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board."*

MH has stated that MH has engaged KPMG to satisfy this directive and this report will be available to be reviewed at the next GRA.

QUESTION:

Please indicate and explain the resources currently being used by Manitoba Hydro to assess and manage risk.

RATIONALE FOR QUESTION:

To understand and quantify the risks faced by Manitoba Hydro.

RESPONSE:

Resources currently being used by Manitoba Hydro to assess and manage risk are as follows:

- The Manitoba Hydro Electric Board ("MHEB") is ultimately responsible to ensure that the risks identified in the annual Corporate Risk Management Report are representative of the major risks faced by Manitoba Hydro and that the actions taken to address those risks as described within the report are appropriate. The MHEB is also provided additional information regarding risk during their regularly scheduled meetings.

- The Executive Committee provides overall guidance for Corporate Risk Management across the Corporation and address risk issues as they arise.

- A Corporate Risk Management Committee provides a cross functional forum for establishing and monitoring risk management processes to ensure that principal risks are appropriately identified, assessed, managed and communicated from a Corporate - wide perspective. The Committee is comprised of representatives from all business units at the Division Management level.

- Management and their respective support staff are responsible to manage risks within their areas of accountability to approved tolerance levels. A Corporate Risk Management Department, under the direction of the VP Finance and Regulatory acts as resource for management and assists in coordinating risk management activities.

- Specific committees and / or councils are established in areas where additional oversight and coordination is deemed necessary. Examples include the establishment of an Enterprise Security Council to provide oversight of all physical and technology security, and the Export Power Risk Management Committee that oversees export power risks.

External experts are also engaged on a regular basis to assist on risk issues. Notable examples include the retention of KPMG in 2010 to conduct a comprehensive review of Manitoba Hydro's risk management programs, and ICF International completed an independent assessment of Export Power Sales and Associated Risks in 2009.

Section:	Tab 10	Page No.:	4&5
Topic:	PUB Directives and Interim Orders		
Subtopic:	Order 43/13 Directive 10		
Issue:	Risk		

PREAMBLE TO IR (IF ANY):

In Order 43/10 the Board directed:

> *"10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board."*

MH has stated that MH has engaged KPMG to satisfy this directive and this report will be available to be reviewed at the next GRA.

QUESTION:

Please provide the terms of reference provided by Manitoba Hydro to KPMG related to meeting the Board's Directive 10 of Order 43/13.

RATIONALE FOR QUESTION:

To understand and quantify the risks faced by Manitoba Hydro.

RESPONSE:

Please see the attachment for the terms of reference provided by Manitoba Hydro for the review of the Corporation's financial targets and to respond to the PUB's Directive 10 from Order 43/13.

Manitoba Hydro

SCHEDULE A
TERMS OF REFERENCE 038860

1 BACKGROUND

Following an internal and external review, Manitoba Hydro's current financial targets were set in 1995. Following their establishment in 1995, the financial targets have been internally reviewed and periodically modified as follows:

1995	Achieve and maintain a minimum debt/equity target of 75:25 by 2005/06, achieve and maintain an annual interest coverage ratio in the range of 1.20 to 1.35, by 1998/99 fund all capital construction requirements from internal sources (except when major new generation or transmission are being added to the system)
2001	75:25 debt equity ratio by 2005/06, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities, from internally generated funds.
2002	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and fund all capital expenditures, except major new generation and transmission facilities, from internally generated funds.
2003	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and minimum capital coverage ratio of 1.0 (excluding new major generation and transmission).
2005	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and minimum capital coverage ratio of 1.0 (excluding new major generation and transmission & DSM).
2007	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and minimum capital coverage ratio of 1.0 (excluding new major generation and transmission & new head office building).
2009	Maintain 75:25 debt equity ratio, minimum interest coverage ratio of 1.20 and minimum capital coverage ratio of 1.20 (excluding new major generation and transmission).

See Appendix B for a definition of Manitoba Hydro's current financial targets.

Manitoba Hydro achieved its 75:25 debt equity ratio in 2009 and while Manitoba Hydro is in the strongest financial position in its history, the required investments in existing infrastructure and new generation are expected to place considerable pressure on Manitoba Hydro's key financial ratios in the next decade. It is important for Manitoba Hydro to maintain an appropriate level of equity to withstand a combination of adverse circumstances in order to ensure rate stability for customers and to preserve the Corporation's self-supporting status from a credit rating perspective.

It is important that Manitoba Hydro's financial targets be reviewed to determine their continuing applicability during this period of significant investment and renewal of infrastructure. Manitoba Hydro's latest integrated financial forecast (IFF13), projects Manitoba Hydro's consolidated debt equity ratio to decline to 89:11 by 2022 as a result of the high levels of capital investment and associated debt financing. The debt equity ratio shows improvement following this intense period of capital investment and is projected to return to the 75:25 target by 2034.

Manitoba Hydro is a Crown Corporation of the Province of Manitoba. Providing continuous, reliable, and economical electricity for the people of the province is Manitoba Hydro's mandate. Manitoba Hydro strives to maintain rate stability for its customers through the implementation of reasonable and regular rate increases, while managing a strong financial structure. Manitoba Hydro's rates are projected based on the achievement of its financial targets and maintaining financial stability.

Manitoba Hydro's rates are regulated by the Manitoba Public Utilities Board (PUB) on a cost of service basis. The PUB is concerned about Manitoba Hydro's financial stability as well as the impact of rate increases to Manitoba rate payers. In Order 43/13, the PUB directed Manitoba Hydro to undertake a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to assess the adequacy of Manitoba Hydro's financial reserves.

As part of the recently concluded Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Development Plan, the PUB recommended to the Government of Manitoba that Manitoba Hydro relax its 75:25 debt-to-equity ratio policy to moderate its proposed electricity rate increases. During this NFAT process, Manitoba Hydro produced an extensive amount of financial scenarios based on different development plans and risks associated with those plans.

Manitoba Hydro's financial targets are reviewed and approved by the Manitoba Hydro-Electric Board.

2 DESCRIPTION OF THE SERVICES

The Services include the following components and deliverables (non-exhaustive):

- Provide recommendations of appropriate financial targets for Manitoba Hydro which align with the mandate of Manitoba Hydro and the interests of its stakeholders considering its operating and business outlook and associated risks.
- The financial target recommendations should consider at a minimum the following:
  - The objective of maintaining rate stability for customers while at the same time maintaining safe and reliable service;
  - The period of significant capital investment and infrastructure renewal that Manitoba Hydro is entering into;
  - The maintenance of Manitoba Hydro's self supporting status for credit rating purposes; and

- The financial targets and capital structures of other comparable North American utilities.
- Provide analysis to satisfy the PUB directive to review Manitoba Hydro's operating and financial risks in order to assess the adequacy of financial reserves, including, as appropriate, the use of quantitative and probabilistic analysis. The approach to the use of quantitative and probabilistic analysis should consider Manitoba Hydro's financial modelling capabilities and the extensive financial scenarios provided as part of the NFAT proceeding.
- Provide a report and presentation to the senior management of Manitoba Hydro and the Manitoba Hydro-Electric Board

NOTE: The Work may be subject to review by the Public Utilities Board and/or other parties. Manitoba Hydro may request that the Consultant testify at a Public Utilities Board hearing regarding the results of the Work.

3 EXTRA SERVICES

The Consultant may be required to provide information and/or testify to the PUB, as to their findings, if called upon to do so. Any fees associated with such a request would be paid at the hourly rates in the Contract.

If the services are required after December 31, 2014, the Contractor may increase the hourly rates; and such increases, on a percentage basis of the hourly rate in the Contract shall not be increased by more than the higher of the percentage change in the Consumer Price Index published by Statistics Canada for the twelve (12) month period prior to December 31, 2014.

4 PERFORMANCE TIMELINE

Hydro expects that the Services will be performed in accordance to the following schedule:

DETAIL	DATE
Award of Contract	November 2014
Commencement of services	Immediately upon Award of Contract
Communication of status and results	On-going
Submission of final report	TBD
Presentation	TBD

5 PROGRESS REPORTS

The Consultant shall deliver to Hydro, on a monthly basis, progress reports detailing the status of the Services under a Services Release Order. Monthly progress reports shall include the following information (non-exhaustive):

(a) state of the project including any significant milestones reached;
(b) hours worked on the project during the previous month;
(c) cumulative hours;
(d) cost for the month,
(e) total project cost and the projected hours to complete the project;
(f) percent of work complete must be compared with percent budget spent; and
(g) other information requested by Hydro.

6 APPENDICES

The following appendices are attached to and form an integral part of this Schedule "A" and the Agreement:

APPENDIX A: Proposal Clarification Form

APPENDIX B: Definition - Manitoba Hydro's Current Financial Targets

APPENDIX C: Form 2669 - Employee Equity Survey for Contracted Work or Services in Manitoba

APPENDIX D: Personnel Risk Assessment

7 PERMITS

The Consultant shall secure and maintain all permits, licenses, clearances and approvals now or hereafter required for the performance, delivery and execution of the Services and the Consultants' obligations under the Agreement.

8 EMPLOYEE DATA COLLECTION

The Consultant shall collect, on behalf of Hydro, all information requested on Form 2669 titled EMPLOYMENT EQUITY SURVEY FOR CONTRACTED WORK OR SERVICES IN MANITOBA included as Appendix "C" to this Schedule "A". The collection and handling of the personal information on Form

2669 shall be in compliance with the privacy provisions of The Freedom of Information and Protection of Privacy Act (Manitoba).

The Consultant shall facilitate the completion of Form 2669 by the Consultant's employee on the same day that the Consultant's employee commences work, and submit the form to Hydro. In addition, when the Consultant's employee has been terminated or reclassified, or the Services completed, the Consultant shall immediately forward the information contained in sections S-2 or CS-2 of the form (as applicable) to Hydro. Furthermore, the Consultant shall provide Hydro with regular updates regarding the number of hours worked by the Consultant's individual employees. These updates may be submitted electronically (in Microsoft Excel Spreadsheet format) in conjunction with the Consultant's pay periods, but in any event, must be submitted minimally on a quarterly basis.

The Consultant shall immediately forward to Hydro the information contained in section CS-3 ACCIDENT DATA of Form 2669 when any employee of the Consultant is injured during the performance of the Services.

The Consultant "employee" means an individual employed by the Consultant to perform work or services on behalf of Hydro and who is onsite for one or more working days.

9 PERSONNEL RISK ASSESSMENT

All employees of the Contractor or employees of subcontractors, if any, must be cleared by a personnel risk assessment prior to being allowed on site.

It shall be a condition of the Contract that the Contractor arranges submission of completed forms, included as Appendix D, in order for personnel risk assessments to be conducted. The Contractor shall comply with all applicable privacy laws in carrying out its responsibilities under this section.

Any changes to an individual's criminal background status must be reported to the Purchaser immediately.

At any time prior to or during the performance of the Contract and at the Purchaser's sole discretion, the Contractor may be required to conduct further personal risk assessments on any individual in its employ or its subcontractor's employ, and an individual's existing clearance may be revoked until a follow-up personnel risk assessment is conducted and the results provided to the Purchaser.

10 CONFLICT OF INTEREST

Consultant warrants that to the best of its knowledge the Consultant, its directors, officers, employees, and subcontractors, have and shall continue to have no conflict of interest that may be detrimental to the performance of the Services or to Hydro. Consultant shall provide notice to Hydro of any actual, potential, or apparent conflict of interest immediately upon awareness of same.