PUB/MH I-1

Reference: Reasons for Application

Please re-file Table 4 incorporating the following adjustments:

a) Include 2004 to 2010 actual results and forecast for 2015/16

ANSWER:

Please see the following table for the requested information.

Table 4 - Net Income and Retained Earnings - Electric Operations

(millions of $)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast	2014/15 Forecast	2015/16 Forecast
General Consumers Revenue													
- at approved rates	$ 918	$ 939	$ 984	$ 1 024	$ 1 075	$ 1 127	$ 1 145	$ 1 200	$ 1 191	$ 1 341	$ 1 396	$ 1 408	$ 1 423
- with proposed increases*									-	-	-	56	115
Bipole III Reserve Account	-	-	-	-	-	-	-	-	-	-	(18)	(21)	(22)
Extraprovincial Revenue (net of fuel & power purchased and water rentals)	(289)	307	571	254	366	323	202	172	98	101	139	118	77
Other Revenue	7	4	5	5	8	16	6	6	6	25	13	13	13
	636	1 250	1 560	1 283	1 448	1 466	1 353	1 379	1 295	1 468	1 530	1 573	1 606
Expenses													
Operating & Administrative	283	299	311	323	323	364	378	397	403	463	485	494	542
Finance expense	453	468	468	467	401	433	373	388	385	452	437	499	514
Depreciation & Amortization	274	289	301	311	324	340	358	365	353	392	415	440	437
Capital & other taxes	50	51	53	55	57	64	76	81	83	86	93	101	109
Corporate Allocation	4	6	6	7	8	8	8	9	9	9	9	9	9
	1 064	1 113	1 140	1 163	1 112	1 209	1 193	1 240	1 233	1 403	1 438	1 543	1 611
Non-controlling Interest	-	-	-	-	-	-	-	-	-	13	24	24	18
Net Income	$ (428)	$ 137	$ 420	$ 120	$ 337	$ 257	$ 160	$ 139	$ 61	$ 78	$ 116	$ 55	$ 12
Debt to Equity Ratio - Electric Only	87:13	85:15	81:19	80:20	73:27	77:23	72:28	72:28	74:26	75:25	76:24	78:22	82:18
Interest Coverage Ratio - Electric Only	0.12	1.27	1.83	1.23	1.72	1.50	1.33	1.26	1.11	1.13	1.20	1.09	1.02
Capital Coverage Ratio - Electric Only	(0.42)	1.20	2.52	1.12	1.65	1.82	1.28	1.22	1.10	1.27	1.03	0.86	0.78

* with proposed increases - reflects a 3.95% increase in 2014/15 and forecast rate 3.95% in 2015/16

Financial Results - Assuming No 2014/15 Rate Increase

	2014/15	2015/16
Net Income (Loss)	$ (1)	$ (49)
Retained Earnings	2 582	2 589
Debt to Equity Ratio (consolidated)	79:21	83:17
Interest Coverage Ratio (consolidated)	1.00	0.93
Capital Coverage Ratio (consolidated)	0.78	0.68

Financial Results (after the proposed rate increase)

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Retained Earnings	707	843	1 263	1 378	1 784	2 028	2 188	2 328	2 390	2 468	2 584	2 638	2 650
Debt to Equity Ratio (consolidated)	87:13	85:15	81:19	80:20	73:27	77:23	73:27	73:27	74:26	75:25	76:24	78:22	82:18
Interest Coverage Ratio (consolidated)	0.17	1.25	1.77	1.23	1.69	1.49	1.32	1.27	1.10	1.15	1.22	1.09	1.03
Capital Coverage Ratio (consolidated)	(0.32)	1.20	2.28	1.10	1.62	1.77	1.34	1.25	1.13	1.25	1.06	0.87	0.80

PUB/MH I-1

Reference: Reasons for Application

Please re-file Table 4 incorporating the following adjustments:

b) The financial Targets for Electric operations

ANSWER:

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

<u>PUB/MH I-2</u>

Reference: Application Page 3 of 21

Please populate the following table for each of the years 1999/00 through 2014/15:

	1999/ 2000	2000/01	[…]	2014/15
% Rate Increase Requested				
% Rate increase approved by PUB				
Annualized dollar increase from Rate increase				
Annual Inflation Rate in Manitoba				

<u>ANSWER</u>:

Please see the table on the following page:

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI	Annual Increase in Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue From Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
1999/00	0.0%	0.0%	2.2%	$0	0.00%	2.2%	$0	66%	83:17
2000/01	0.0%	0.0%	2.5%	0	0.00%	4.76%	0	62%	80:20
2001/02	0.0%	-1.92% Nov 1/01	2.1%	(14.4)	-1.92%	6.95%	(14.4)	57%	77:23
2002/03	0.0%	0.0%	2.3%	0	-1.92%	9.41%	(14.4)	65%	80:20
2003/04	0.0%	-0.72% April 1/03	0.9%	(6.5)	-2.63%	10.40%	(20.9)	72%	87:13
2004/05	3% April 1/04	5.0% August 1/04	2.7%	32.3	2.24%	13.38%	11.4	63%	85:15
2005/06	2.5% April 1/05	2.25% April 1/05	2.4%	21.8	4.54%	16.10%	33.2	54%	81:19
2006/07	2.25% February 1/07	2.25% March 1/07	2.0%	23.1	6.90%	18.42%	56.3	63%	80:20
2007/08	0.0% April 1/07	0.0% April 1/07	1.9%	-	6.90%	20.67%	56.3	63%	73:27
2008/09	2.9% April 1/08	5.0% July 1/08	2.2%	52.4	12.24%	23.33%	108.7	64%	77:23
2009/10	3.9% April 1/09	2.86% April 1/09	0.6%	32.8	15.45%	24.07%	141.5	72%	73:27
2010/11	2.9% April 1/10	2.84% April 1/10	1.0%	32.9	18.73%	25.31%	174.4	74%	73:27
2011/12	2.9% April 1/11	2.0% April 1/11	2.8%	24.4	21.10%	28.82%	198.8	76%	74:26
2012/13	3.5% April 1/12	2.0% April 1/12	1.6%	25.8	23.53%	30.88%	224.6	79%	75:25
2012/13	2.5% Sept 1/12	2.4% Sept 1/12	1.6%	31.0	26.49%	32.97%	255.6	79%	75:25
2013/14	3.5% April 1/13	3.5% May 1/13	1.8%	47.6	30.92%	35.37%	303.2	77%	76:24
2014/15*	3.95% April 1/14	To be determined	2.0%	55.6	36.09%	38.07%	358.8	78%	78:22

* To calculate the annual increase in revenue and the cumulative % rate increase, approval of a 3.95% rate increase effective April 1, 2014 has been assumed.

Notes:

2001/02 Uniform Rate Legislation – the Government of Manitoba legislated uniform rates effective November 1, 2001. Under a uniform rate structure all customers living outside the City of Winnipeg pay the same electricity rates as customers located in Winnipeg.

2003/04 Status Update – a status update hearing was held in 2002 to review Manitoba Hydro's financial status. As a result the Public Utilities Board directed Manitoba Hydro to reduce rates to the General Service rate class effective April 1, 2003 (a 1% reduction for GS Small, 2% reduction for GS Large, and a reduction in the winter ratchet from 80% to 70%).

Note: Cumulative increases do not take annual changes in load into consideration. Please see the response to PUB/MH I-3 for the impact in changes in load.

PUB/MH I-3

Reference: Interim Application - Proposed Rates & Customer Impacts

Please file an update to PUB/MH II-56 (a) from the 2012 GRA and incorporate the 2014/15 requested rate increases. Please also include both gross and net export revenues.

ANSWER:

Please see the following table for the requested information.

MANITOBA HYDRO
GENERAL CONSUMERS REVENUE **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast	2014/15 Forecast
Residential - Base Rates	$ 373 737	$ 360 363	$ 381 532	$ 397 742	$ 405 896	$ 401 304	$ 411 995	$ 390 436	$ 437 222	$ 416 116	$ 418 393
General Service - Base Rates	534 958	555 836	570 078	581 124	583 448	563 954	571 525	584 748	604 274	624 175	627 590
Base Rates	908 694	916 198	951 610	978 865	989 345	965 258	983 520	975 183	1 041 495	1 040 291	1 045 983
2004/05 Approved Rate Increase (5.0% August 1, 2004)	30 260	45 810	47 580	48 943	49 467	48 263	49 176	48 759	52 075	52 015	52 299
2005/06 Approved Rate Increase (2.25% April 1, 2005)	-	21 645	22 482	23 126	23 373	22 804	23 236	23 039	24 605	24 577	24 711
2006/07 Approved Rate Increase (2.25% March 1, 2007)	-		1 941	23 646	23 899	23 317	23 758	23 557	25 159	25 130	25 267
2008/09 Approved Rate Increase (5.0% July 1, 2008)	-	-	-	-	40 728	52 982	53 984	53 527	57 167	57 101	57 413
2009/10 Approved Rate Increase (2.9% April 1, 2009)	-	-	-	-	-	32 266	32 877	32 598	34 815	34 774	34 965
2010/11 Interim Rate Increase (2.9% April 1, 2010)	-	-	-	-	-	-	33 830	33 543	35 824	35 783	35 979
2011/12 Approved Rate Increase (2.0% April 1, 2011)	-	-	-	-	-	-	-	23 804	25 423	25 393	25 532
2012/13 Approved Rate Increase (2.0% April 1, 2012	-	-	-	-	-	-	-	-	25 931	25 901	26 043
2012/13 Approved Rate Increase (2.4% September 1, 2012)									18 515	31 703	31 877
2013/14 Approved Rate Increase (3.5% May 1, 2013)										43 421	47 602
Interim & Approved Rate Increases	30 260	67 455	72 003	95 715	137 468	179 633	216 861	238 827	299 513	355 797	361 688
2010/11 (1% rate rollback)	-	-	-	-	-	-	-	(22 894)	-	-	-
Deferred Revenue from 1% rate rollback	-	-	-	-	-	-	-	(22 894)	-	-	-
Additional General Consumers Revenue (3.95% April 1, 2014)	-	-	-	-	-	-	-	-	-	-	55 603
Additional General Consumers Revenue	-	-	-	-	-	-	-	-	-	-	55 603
Bipole III Reserve Account	-	-	-	-	-	-	-	-	-	(18 492)	(21 207)
Bipole III Reserve Account	-	-	-	-	-	-	-	-	-	(18 492)	(21 207)
Total General Consumer Revenue	$ 938 954	$ 983 653	$ 1 023 613	$ 1 074 580	$ 1 126 812	$ 1 144 891	$ 1 200 381	$ 1 191 117	$ 1 341 009	$ 1 377 596	$ 1 442 068
Rate increase requested	3.00%	2.50%	2.25%	n/a	2.90%	3.90%	2.90%	2.90%	3.50%	3.50%	3.95%
Rate increase granted	5.00%	2.25%	2.25%	n/a	5.00%	2.90%	1.90%	2.00%	2.0%/2.4%	3.50%	n/a

MANITOBA HYDRO
EXTRAPROVINCIAL REVENUE **(000's)**

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast	2014/15 Forecast
Extraprovincial Revenue	$ 553 727	$ 826 766	$ 592 245	$ 624 971	$ 622 646	$ 426 641	$ 398 306	$ 363 044	$ 352 633	$ 408 426	$ 382 904
Water Rentals and Assessments	(135 456)	(124 841)	(226 212)	(134 887)	(176 383)	(103 973)	(106 169)	(145 632)	(133 292)	(124 900)	(122 535)
Fuel and Power Purchased	(111 521)	(131 020)	(112 497)	(123 767)	(123 000)	(121 033)	(120 163)	(119 301)	(117 864)	(144 355)	(142 307)
Net Extraprovincial Revenue	$ 306 750	$ 570 905	$ 253 536	$ 366 316	$ 323 264	$ 201 635	$ 171 974	$ 98 111	$ 101 477	$ 139 171	$ 118 062

PUB/MH I-4

Reference: Interim Application - Proposed Rates

a) Please indicate when the Corporation proposes filing a General Rate Application in support of its Interim Rate Application.

ANSWER:

Manitoba Hydro intends to file a General Rate Application in the fall of 2014. In that Application, Manitoba Hydro will seek final approval of any rate increase flowing from this Interim Rate Application, and will seek further rate increases for 2015/16 and 2016/17.

PUB/MH I-4

Reference: Interim Application - Proposed Rates

b) Please advise when the Corporation proposes to hold a Cost of Service and Time of Use Hearing.

ANSWER:

Manitoba Hydro proposes to examine Cost of Service (“COS”) and Time of Use (“TOU”) Rates matters through a collaborative stakeholder process commencing in the summer of 2014. Given the technical aspects of COS and TOU matters, a collaborative process would complement the traditional regulatory process by allowing participants an opportunity to achieve a better understanding of the issues and reach as much consensus as possible on matters affecting the parties prior to the start of the public hearing.

PUB/MH I-5

Reference: Application Page 11 to 14 of 21, Table 4

a) Please provide an updated comparative analysis schedule comparing the income for fiscal years 2013/14, 2014/15, and 2015/16. Please include a narrative explanation of the changes.

ANSWER:

Please see the updated schedule for the requested information.

The 2014/15 versus 2013/14 forecast explanations can be found on page 15 of the Application. The 2015/16 versus 2014/15 explanations are provided below.

The forecasted general rate increase of 3.95% effective April 1, 2015 is expected to generate additional revenue of $59 million in 2015/16. With this increase, the forecast net income from electricity operations for 2015/16 is projected to be $12 million, which is a reduction of $42 million over the previous fiscal year.

The reduction in forecast net income for 2015/16 is primarily the result of a reduction in net extraprovincial revenues ($41 million), increased O&A ($48 million) and increased capital and other taxes expense ($9 million), somewhat offset by the requested rate increase ($59 million) and increased domestic load ($16 million).

As stated in Manitoba Hydro's Application, due to the timing of the approval of MH13, 2014/15 uses expected inflow conditions for the forecast year, rather than using the median of historic inflows. Above average hydraulic generation is anticipated for 2014/15. For

2015/16 projections are determined by averaging the revenues using flow conditions for 99 years (1912/13 to 2010/11). Due to these average water conditions, MH13 shows lower net extraprovincial revenue.

O&A is $48 million higher due to the expensing of additional Administrative Overhead ($54 million) in 2015/16 as a result of the implementation of IFRS less decreases related to additional cost containment measures ($5 million).

The forecast (MH13) to forecast (MH12) changes for 2015/16 result in a $60 million reduction to net income. The reduction to forecast net income is primarily attributable to reduced domestic revenues due to a reduction in expected load growth ($16 million), the allocation of revenues to the Bipole III reserve account ($22 million) as well as increased depreciation ($8 million) and a net decrease of $10 million due to the continuation of the use of rate regulated accounting.

ELECTRIC OPERATIONS (MH13)
PROJECTED INCOME STATEMENT

For the year ended March 31	2013/14			2014/15			2015/16		
(millions of $)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	MH13 Forecast	MH12 Forecast	Increase (Decrease)
GCR									
-at approved rates	1 396	1 361		1 408	1 374		1 423	1 390	
-with additional rate increases *	-	48		56	104		115	165	
	1 396	1 409	(12)	1 463	1 478	(15)	1 538	1 554	(16)
Bipole III Reserve Account	(18)	-	(18)	(21)	-	(21)	(22)	-	(22)
Extraprovincial (net of fuel & power purchased and wate	139	62	77	118	53	65	77	78	(1)
Other Revenue	13	15	(2)	13	15	(2)	13	15	(2)
Total Revenue	1 530	1 486	44	1 573	1 545	28	1 606	1 647	(41)
Operating & Administrative	485	471	14	494	544	(49)	542	556	(14)
Finance Expense	437	444	(8)	499	492	7	514	524	(11)
Depreciation & Amortization	415	430	(15)	440	372	67	437	391	46
Capital & Other Taxes	93	96	(3)	101	101	-	109	110	(1)
Corporate Allocation	9	9	-	9	8	1	9	8	0
Total Expenses	1 438	1 450	(12)	1 543	1 517	25	1 611	1 590	21
Non-Controlling Interest	24	24	(1)	24	21	3	18	16	2
Net Income	116	60	55	55	50	5	12	73	(60)
Retained Earnings (Electric)	2 584	2 502	82	2 638	2 295	343	2 592	2 368	224
Debt to Equity Ratio (consolidated)	76:24	78:22		78:22	83:17		82:18	85:15	
Interest Coverage Ratio (consolidated)	1.22	1.11	0.11	1.09	1.09	-	1.03	1.11	(0.08)
Capital Coverage Ratio (consolidated)	1.06	0.89	0.17	0.87	0.83	0.04	0.80	0.94	(0.14)

* -with additional rates increases includes the proposed rate 3.95% in 2014/15 and forecast rate 3.95% in 2015/16

PUB/MH I-5

Reference: Application Page 11 to 14 of 21, Table 4

b) Please provide a comparative analysis schedule comparing the financial targets, balance sheet, and cash flow statement for fiscal years 2013/14, 2014/15, and 2015/16 for electric operations only, comparing the forecast presented in IFF 12-1 with the updated information for each of those years. Please include a narrative explanation of any material changes. Please provide a similar analysis comparing IFF 09–1 with the most current information.

ANSWER:

Please see the following tables for the requested information.

ELECTRIC OPERATIONS -Comparison (MH13 to MH12)
PROJECTED BALANCE SHEET

For the year ended March 31	2013/14			2014/15			2015/16			
(millions of $)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	
Assets										
Net Plant in Service	10 803	10 899	(96)	11 568	11 248	320	12 137	12 032	105	2013/14 - Assets to be placed in-service were deferred in MH13 2014/15 - Increased base capital spending results in more plant in-service including deferred plant from 2013/14. 2015/16 - Increased base capital spending placed in-service
Construction in Progress	2 425	2 878	(453)	3 296	4 198	(903)	4 743	5 128	(386)	Construction in progress is decreased with more base capital being placed in service and lower MNG&T spending in the first two years.
Other Assets	2 058	2 125	(67)	2 054	1 541	513	1 890	1 712	178	2013/14 - mostly due to cash balances at year end. 2014/15 - cash balances and regulated assets were assumed to be written off in MH12 2015/16 -Regulated assets assumed to be written off in MH12
	15 285	15 902	(616)	16 918	16 988	(70)	18 770	18 873	(103)	
Liabilities and Equity										
Long Term Debt and Other Liabilities	12 117	12 768	(650)	13 664	14 484	(821)	15 849	16 339	(491)	2013/14 -actual debt balances from 2012/13 were less than forecast in MH12 and less debt required for MNG&T 2014/15 - less debt requirement due to lower forecasted MNG&T spending 2015/16 - less debt requirement due to lower forecasted MNG&T spending, offset by higher base capital spending
Contributions	380	345	35	412	350	62	443	355	89	Increases for BPIII reserve
Retained Earnings	2 584	2 502	82	2 638	2 295	343	2 592	2 368	224	2013/14 - Higher net income than forecast in MH12 2014/15 - Higher net income and no write offs for IFRS 2015/16 -no assumed write-off of rate-regulated assets
Accumulated Other Comprehensive Income	204	287	(83)	204	(142)	346	(115)	(189)	75	2014/15 - deferral of reclassification of unamortized pension losses to AOCI under IFRS
	15 285	15 902	(616)	16 918	16 988	(70)	18 770	18 873	(103)	
Financial Ratios										
Equity (Electric)	76:24	78:22		78:22	83:17		82:18	85:15		
Interest Coverage (Electric)	1.20	1.10	0.10	1.09	1.07	0.02	1.02	1.09	(0.07)	
Capital Coverage (Electric)	1.03	0.89	0.14	0.86	0.77	0.09	0.78	0.90	(0.12)	

ELECTRIC OPERATIONS -Comparison (MH13 to MH12)
PROJECTED CASH FLOW STATEMENT

For the year ended March 31	2013/14			2014/15			2015/16			
(millions of $)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	MH13 Forecast	MH12 Forecast	Increase (Decrease)	
Operating Activities										
	544	486	58	549	442	108	493	478	15	
Financing Activities										
	1 000	1 548	(548)	1 616	1 670	(54)	2 261	1 886	376	2013/14 - Lower debt requirements 2015/16 -Increasing debt requirements
Investing Activities										
	(1 786)	(2 151)	364	(2 175)	(2 173)	(2)	(2 644)	(2 291)	(353)	2013/14 - Lower capital investments 2015/16 -Increasing capital investments
Net Increase (Decrease) in Cash	(243)	(117)	(126)	(10)	(62)	52	111	73	38	
Cash at Beginning of Year	25	(51)	76	(218)	(168)	(49)	(227)	(230)	3	
Cash at End of Year	(218)	(168)	(49)	(227)	(230)	3	(117)	(157)	40	

ELECTRIC OPERATIONS -Comparison (MH13 to MH09)
PROJECTED BALANCE SHEET
For the year ended March 31
(millions of $)

	2013/14			2014/15			2015/16			
	MH13 Forecast	MH09-1 Forecast	Increase (Decrease)	MH13 Forecast	MH09-1 Forecast	Increase (Decrease)	MH13 Forecast	MH09-1 Forecast	Increase (Decrease)	
Assets										
Net Plant in Service	10 803	9 765	1 037	11 568	10 042	1 526	12 137	10 035	2 102	2013/14 - increased assets placed in-service in MH13 2014/15 - Increased base capital spending results in more plant in-service. 2015/16 - Increased base capital spending placed in-service
Construction in Progress	2 425	2 838	(413)	3 296	3 854	(558)	4 743	5 532	(789)	Construction in progress is decreased with more base capital being placed in service and lower MNG&T spending in the first three years.
Other Assets	2 058	2 750	(692)	2 054	2 902	(847)	1 890	3 089	(1 199)	Pension assets net of pension liabilities in MH13 versus MH09 reported gross
	15 285	15 353	(68)	16 918	16 798	120	18 770	18 656	114	
Liabilities and Equity										
Long Term Debt and Other Liabilities	12 117	12 455	(337)	13 664	13 811	(147)	15 849	15 456	393	Debt values are higher in MH13 due to increased capital spending, offset by the change in reporting of pension assets net of pension liabilities in years 1 and 2, and partially offset in year 3
Contributions	380	276	104	412	275	137	443	274	170	Increases for BPIII reserve and higher forecasted and actual customer contributions
Retained Earnings	2 584	2 528	55	2 638	2 641	(3)	2 592	2 889	(297)	2015/16- lower net income than MH09
Accumulated Other Comprehensive Income	204	94	110	204	71	133	(115)	38	(152)	2015/16- reclassification of unamortized pension losses to AOCI under IFRS in MH13
	15 285	15 353	(68)	16 918	16 798	120	18 770	18 656	114	
Financial Ratios										
Equity (Electric)	76:24	78:22		78:22	79:21		82:18	80:20		
Interest Coverage (Electric)	1.20	1.19	0.01	1.09	1.15	(0.06)	1.02	1.30	(0.28)	
Capital Coverage (Electric)	1.03	1.25	(0.22)	0.86	1.53	(0.67)	0.78	1.89	(1.11)	

ELECTRIC OPERATIONS -Comparison (MH13 to MH09)
PROJECTED CASH FLOW STATEMENT
For the year ended March 31
(millions of $)

	2013/14			2014/15			2015/16			
	MH13 Forecast	MH09-1 Forecast	Increase (Decrease)	MH13 Forecast	MH09-1 Forecast	Increase (Decrease)	MH13 Forecast	MH09-1 Forecast	Increase (Decrease)	
Operating Activities										
	544	579	(35)	549	596	(47)	493	734	(242)	Lower Revenue Forecasts
Financing Activities										
	1 000	1 220	(220)	1 616	1 288	327	2 261	1 528	733	2013/14 - Lower debt requirements 2014/15 - Increasing debt requirements 2015/16 -Increasing debt requirements
Investing Activities										
	(1 786)	(1 648)	(138)	(2 175)	(1 876)	(299)	(2 644)	(2 355)	(289)	2013/14 - increasing capital investments 2014/15 - Increasing capital investments 2015/16 -Increasing capital investments
Net Increase (Decrease) in Cash	(243)	151	(393)	(10)	9	(19)	111	(92)	203	
Cash at Beginning of Year	25	(109)	134	(218)	41	(259)	(227)	51	(278)	
Cash at End of Year	(218)	41	(259)	(227)	51	(278)	(117)	(41)	(75)	

PUB/MH I-5

Reference: Application Page 11 to 14 of 21, Table 4

c) Please refile Table 4 assuming the requested rate increase is not approved.

ANSWER:

Please see the following table for the requested information:

Net Income and Retained Earnings - Electric Operations - Assuming no Rate Increase
(millions of $)

	2011/12 Actual	2012/13 Actual	2013/14 Forecast	2014/15 Forecast
General Consumers Revenue				
- at approved rates	$ 1 193	$ 1 341	$ 1 396	$ 1 408
Bipole III Reserve Account	-	-	(18)	(20)
Extraprovincial Revenue (net of fuel & power purchased and water rentals)	98	101	139	118
Extraprovincial revenue	363	353	408	383
Fuel & power purchased	(146)	(133)	(144)	(142)
water rentals	(119)	(118)	(125)	(123)
Other Revenue	13	25	13	13
	1 304	1 468	1 530	1 518
Expenses				
Operating & Administrative	412	463	485	494
Finance expense	385	452	437	500
Depreciation & Amortization	353	392	415	440
Capital & other taxes	83	86	93	101
Corporate Allocation	9	9	9	9
	1 242	1 403	1 438	1 544
Non-controlling Interest	-	13	24	24
Net Income	$ 61	$ 78	$ 116	$ (1)

PUB/MH I-6

Reference: Appendix 1, Financial Results

a) Please file the Q4 2013/14 draft financial results for electric operations, including financial ratios.

ANSWER:

Manitoba Hydro's financial results for the fourth quarter of fiscal 2013/14 are not yet available. Furthermore, pursuant to Sections 7 and 8 of *The Crown Corporations Public Review and Accountability Act* and Section 46 of *The Manitoba Hydro Act*, Manitoba Hydro is not in a position to publicly release its financial results until its Quarterly or Annual Reports have been tabled with the Legislative Assembly.

PUB/MH I-6

Reference: Appendix 1, Financial Results

b) Please provide a comparison of the draft 2013/14 electric results with those forecast in MH13-1.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-6(a).

PUB/MH I-6

Reference: Appendix 1, Financial Results

c) Please indicate to what extent the actual financial results for Q3 were incorporated in the forecast for 2013/14 in MH13-1

ANSWER:

Actual financial results to the end of December 2013 were incorporated into the Generation Revenue and Costs estimates to enable the use of the latest forecast of expected inflows based on conditions as of January 7, 2014, using initial reservoir and lake levels at January 1, 2014, for the remainder of fiscal year and into 2014/15.

Other Q3 financial results were not incorporated into the forecast as revised estimates for remaining variables were not available or did not change the annual forecast significantly.

PUB/MH I-7

Reference: **Appendix 1 Page 2**

Preamble: **The Corporation states that the "economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook, with certain key variables updated as of November 2013."**

a) **Please provide details of the "key variables" that were updated and how the changes impacted MH13-1.**

ANSWER:

The following summarizes the variables that were updated in November 2013 and the related impacts that have already been incorporated into MH13-1 for the forecasted years 2013/14 to 2016/17:

	M.H. Short Term Cdn Tbill Rate	M.H. Short Term Cdn BA Rate	M.H. Short Term U.S. Interest Rate	M.H. Long Term Cdn 10 Year + Rate	M.H. Long Term U.S. 10 Yr Rate
2013/14	-0.05%	-0.05%	-0.20%	0.25%	0.35%
2014/15	-0.30%	-0.30%	-0.35%	0.20%	0.35%
2015/16	-0.25%	-0.20%	-0.05%	0.15%	0.30%
2016/17	-0.15%	-0.15%	0.00%	-0.35%	0.05%

Generally, the impacts of the increases to long-term rates in the first three years of the forecast are partially offset by the impacts of lower short-term rates in all four years and the lower long-term Canadian interest rate in year four.

PUB/MH I-7

Reference: Appendix 1 Page 2

Preamble: The Corporation states that the "economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook, with certain key variables updated as of November 2013."

b) Please file the spring 2014 Economic Outlook when available.

ANSWER:

The 2014 Economic Outlook is not currently available.

As indicated in the response to PUB/MH 4(a), Manitoba Hydro intends to file a General Rate Application in the fall of 2014. A copy of the 2014 Economic Outlook will be provided in support of that application.

PUB/MH I-8

Reference: Application Page 13

a) What is the basis for the Corporation's conclusion that extraprovincial revenue is going to decrease over the next three years, as opposed to increase?

ANSWER:

The reduction in extraprovincial revenues from 2013/14 to 2014/15 is primarily due to the following factors:

- Lower hydraulic generation is expected in 2014/15 compared to 2013/14. Although above average spring run-off is forecasted for 2014/15, overall water supply is projected to be lower than compared to 2013/14.
- The 500kV tieline to the U.S. is scheduled to be out of service for October 2014 which will restrict export sales.
- Merchant sales activity in 2013/14 were well above average. The 2014/15 forecast for merchant sales reflects normal merchant profits.

Lower extraprovincial revenues for 2015/16 are projected compared to 2014/15 due to the following:

- Hydraulic generation and projections of surplus energy available for export in 2015/16 is based on the average from 99 historic flow years. This average is lower than the above average surpluses projected in 2014/15.

PUB/MH I-8

Reference: Application Page 13

b) Please provide a breakdown of the factors the Corporation considers to be relevant in the reduction of export revenue in 2014/15.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-8(a).

PUB/MH I-9

Reference: Appendix 3 Q 4 Financial Results

a) Please indicate the Heating Degree Days which MH has experienced in the first 9 months of 2013/14 and the last three months of the fiscal year and provide the normal DDH for these periods.

ANSWER:

The first nine months of 2013/14 experienced 2,611 Heating Degree Days compared to 2,187 Heating Degree Days for a normal year. The last three months of the 2013/14 experienced 2,809 Heating Degree Days compared to 2,354 Heating Degree Days for a normal year.

The following presents the monthly Heating Degree Day summary for the 2013/14 fiscal year.

Month	2013/14	Normal
Apr	482	295
May	116	121
Jun	13	18
Jul	2	2
Aug	1	5
Sep	32	71
Oct	294	277
Nov	592	554
Dec	1,078	845
Jan	1,034	944
Feb	949	786
Mar	826	625
Total	5,420	4,541

Note: Total may not add up due to rounding

PUB/MH I-9

Reference: Appendix 3 Q 4 Financial Results

b) Please estimate the relationship between heating degree days and domestic revenues.

ANSWER:

The estimated relationship between heating degree days and domestic revenue is approximately $55,000 per Heating Degree Day.

PUB/MH I-9

Reference: Appendix 3 Q 4 Financial Results

c) Please provide an analysis and narrative that explains the reported increase in OM&A costs for the 9 months ended December 31, 2013.

ANSWER:

The increase in Electric OM&A costs, $16.4 million, for the 9 months ended December 31, 2013 as compared to the 9 months ended December 31, 2012 relates to higher pension and other benefits costs primarily as a result of the lowering of the discount rate.

The discount rate used to value pensions and post-employment benefits must be in compliance with Canadian Accounting Standard CICA 3461.063. As a result of market conditions, the discount rate decreased for both pension and post-employment benefit costs in the current year. The lowering of the discount rate results in an increase in pension and benefit obligations which resulted in increased employee benefit costs.

The following table provides the change in OM&A costs for the 9 months ended December 31, 2013:

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	Nine Months Ended December 31 2013	2012	Change
Wages & Salaries	$ 358,361	$ 351,042	$ 7,319
Overtime	45,203	44,927	276
Employee Benefits	108,142	86,266	21,876
Employee Safety & Training	2,815	2,918	(103)
Travel Expenses	23,297	23,521	(224)
Motor Vehicle	21,331	21,284	47
Materials & Tools	20,805	18,860	1,944
Consulting & Professional Fees	9,491	6,886	2,605
Construction & Maintenance Services	12,456	11,535	921
Building & Property Services	21,044	15,333	5,711
Equipment Maintenance & Rentals	11,332	10,747	585
Consumer Services	3,970	3,792	178
Collection Costs	3,193	3,185	8
Customer & Public Relations	3,915	4,430	(516)
Sponsored Memberships	594	991	(397)
Office & Administration	11,008	10,333	676
Computer Services	507	581	(74)
Communication Systems	1,516	1,385	131
Research & Development Costs	1,138	1,786	(648)
Miscellaneous Expense	1,007	1,005	2
Operating Expense Recovery	(12,119)	(9,205)	(2,914)
Less: Capital Order Activities	(194,912)	(175,884)	(19,028)
Less: Capitalized Overhead	(54,743)	(54,470)	(272)
Less: O&A Charged to Gas Operations	(48,976)	(47,303)	(1,673)
Total Electric OM&A	**350,375**	**333,945**	**16,430**
Total Gas OM&A	48,976	47,303	1,673
Total Subsidiaries OM&A	6,066	2,726	3,340
Consolidated OM&A (Quarterly Report)	**$ 405,417**	**$ 383,974**	**$ 21,444**

PUB/MH I-9

Reference: Appendix 3 Q 4 Financial Results

d) Please indicate the revenue requirement impact in the Q3 report related to Wuskwatim operations.

ANSWER:

This information is expected to be provided in the response to Undertaking 49 at the NFAT hearing.

PUB/MH I-10

Reference: Application Page 15, Appendix 1 page 7

a) Please provide a summary update detailing the proposed IFRS-related accounting changes that are to take effect in 2013/14, 2014/15 and 2015/16.

ANSWER:

Please see the following schedules for a summary update detailing the proposed accounting changes that are to take effect in 2013/14, 2014/15 and 2015/16.

- Schedule A presents the net impacts of accounting changes in IFF13 by operating statement line item under CGAAP and IFRS.
- Schedule B presents the net impacts of the accounting changes to Retained Earnings.

Please note that no additional accounting changes under CGAAP are anticipated to be implemented in IFF13 for the period 2013/14 – 2014/15. Additional accounting changes to comply with IFRS will be implemented by Manitoba Hydro upon its transition to IFRS in fiscal 2015/16.

SCHEDULE A - ACCOUNTING CHANGES - IFF13

	Forecast --> 2014	2015	2016
Electric only (in millions of $'s)			
OM&A			
CGAAP Changes			
Intangibles			
DSM	1	1	1
Planning Studies	2	2	2
IT Application	1	1	1
Total	4	4	4
Overhead Capitalized			
Stores	6	6	6
Admin& General	53	54	54
Total	58	59	60
Change in Discount Rate on Pension & Other Benefits	24	27	27
Subtotal CGAAP Changes	86	91	91
IFRS Changes			
Pension		-	1
Employee Benefits (amortization of RHSA)		-	(6)
Admin & General		-	52
Subtotal IFRS Changes		-	47
Reclassifications			
Wire & Telecom Services	3	3	3
Funding Agreements	(5)	(6)	(6)
Operating Expense Recoveries	8	8	8
Subtotal Reclassifications	6	6	6
Total OM&A Accounting Changes	92	97	145

SCHEDULE A - ACCOUNTING CHANGES - IFF13 cont'd

Electric only (in millions of $'s)	Forecast -->		
DEPRECIATION EXPENSE	2014	2015	2016
CGAAP Changes			
Administrative & General Overhead Capitalized	(4)	(5)	(6)
Average Service Life	(43)	(48)	(51)
Subtotal CGAAP Changes	(47)	(53)	(57)
IFRS Changes			
Administrative & General Overhead Capitalized			(1)
Change to Equal Life Group Depreciation Method			35
Removal of Net Salvage from depreciation rates			(58)
Subtotal IFRS Changes	-	-	(24)
Total Depreciation Accounting Changes	(47)	(53)	(81)
FINANCE EXPENSE			
CGAAP Changes	-	-	-
IFRS Changes	-	-	-
Total Finance Expense Accounting Changes	-	-	-
CAPITAL TAX EXPENSE			
CGAAP Changes	-	-	-
IFRS Changes	-	-	(2)
Total Capital Tax Expense Accounting Changes	-	-	(2)

SCHEDULE B - ACCOUNTING CHANGES IMPACT TO RETAINED EARNINGS - IFF13

Electric only (in millions of $'s) **IMPACT TO RETAINED EARNINGS**	Forecast --> 2014	2015	2016	**Total**
CGAAP Changes				
Annual change to OM&A	(86)	(91)	(91)	**(268)**
Annual change to Depreciation & Amortization	47	53	57	**157**
Wire & Teleom Services moved to MHI	(3)	(3)	(3)	**(10)**
Total	**(42)**	**(41)**	**(38)**	**(121)**
IFRS Changes				
Annual change to OM&A	-	-	(47)	**(47)**
Annual change to Depreciation & Amortization	-	-	24	**24**
Annual change to Finance & Capital Tax Changes	-	-	2	**2**
Adjustments for:				
Administrative Overhead			(51)	**(51)**
Removal of Net Salvage Depreciation			57	**57**
Change to Equal Life Group Depreciation			(34)	**(34)**
Employee Benefits			(30)	**(30)**
Total	**-**	**-**	**(79)**	**(79)**
Total Annual Impact to Retained Earnings	**(42)**	**(41)**	**(117)**	**(201)**

PUB/MH I-10

Reference: Application Page 15, Appendix 1 page 8

b) Please discuss and provide details on how the Interim Standard for Regulatory Deferral Accounts has impacted the income statement and balance sheet in MH13-1, isolating the impact of the accounting changes.

ANSWER:

As a result of the IASB's Interim standard IFRS 14 – Regulatory Deferral Accounts, Electric rate regulated accounts recognized prior to the transition to IFRS continue to be deferred and amortized in IFF13. Although IFRS 14 is not effective until periods after January 2016, entities can early adopt the interim standard. Manitoba Hydro will be early adopting the standard upon its April 1, 2015 transition to IFRS. The following table depicts the Electric regulatory account balances and activity in fiscal 2015-16.

Electric - Regulatory Deferral Accounts

Forecast - Fiscal 2015/16

(In millions of dollars)

	Opening Balance	Additions	Amortization	Ending Balance
Demand Side Management	164	25	(33)	156
Site Remediation	30	3	(4)	29
Regulatory Costs	2	1	(1)	2
Acquisition Costs	17		(1)	16
Total	**213**	**28**	**(38)**	**203**

If IFRS 14 was not available to Manitoba Hydro upon transition to IFRS in fiscal 2015/16, Manitoba Hydro would have been required to do the following:

- Adjust approximately $213 million in electric regulatory account balances to retained earnings upon transition;
- Operating and Administrative expense would have increased by $28 million for 2015/16 spending on the regulatory balances; and
- 2015/16 amortization expense would have decreased by $38 million as amortization would not have been recognized following the adjustment of the opening balances to retained earnings.

PUB/MH I-11

Reference: Appendix 1, IFF13 Page I & iii

Please provide the financial results and projected net income and key financial ratios for electric operations only and provide a comparison with those presented in IFF12.

ANSWER:

Please see the following table for the requested information.

MH13 Electric Operations	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electric Rate Increases*	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Net Income	116	55	12	19	(12)	(67)	(31)	(75)	(60)	6	68	133	168	281	277	259	408	532	742
Retained Earnings	2 584	2 638	2 592	2 611	2 599	2 533	2 502	2 427	2 366	2 372	2 440	2 572	2 741	3 022	3 299	3 558	3 967	4 499	5 241
Capital Expenditures	1 597	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
Equity	24%	22%	18%	16%	15%	14%	12%	12%	11%	10%	10%	10%	10%	11%	11%	12%	13%	15%	18%
Interest Coverage	1.20	1.09	1.02	1.02	0.99	0.94	0.97	0.94	0.96	1.00	1.04	1.08	1.10	1.16	1.15	1.14	1.22	1.29	1.42
Capital Coverage	1.03	0.86	0.78	0.84	1.12	1.01	1.14	1.16	1.32	1.51	1.68	1.82	1.89	2.20	2.33	2.40	2.68	2.94	3.34

MH12 Electric Operations	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electric Rate Increases	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Net Income	60	50	73	57	19	(68)	(9)	(7)	52	163	228	301	358	418	370	534	710	835	1 054
Retained Earnings	2 502	2 295	2 368	2 425	2 444	2 376	2 368	2 361	2 413	2 576	2 804	3 105	3 463	3 881	4 251	4 785	5 495	6 330	7 384
Capital Expenditures	1 859	2 009	2 075	2 218	2 185	1 879	1 684	1 819	2 320	2 286	2 040	1 845	1 577	1 432	888	1 085	1 006	951	816
Equity	22%	17%	15%	14%	13%	12%	11%	10%	10%	10%	10%	11%	12%	13%	14%	16%	18%	20%	24%
Interest Coverage	1.10	1.07	1.09	1.06	1.02	0.94	0.99	0.99	1.04	1.11	1.15	1.19	1.22	1.25	1.22	1.32	1.44	1.53	1.70
Capital Coverage	0.89	0.77	0.90	1.21	1.37	1.11	1.53	1.49	1.61	1.63	1.75	1.91	2.21	2.80	2.47	2.60	2.77	2.88	3.80

MH13 vs. MH12	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electric Rate Increases	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Net Income	55	5	(60)	(39)	(31)	1	(22)	(68)	(112)	(157)	(161)	(169)	(190)	(136)	(93)	(275)	(301)	(303)	(312)
Retained Earnings	82	343	224	186	155	157	134	66	(46)	(204)	(364)	(533)	(723)	(859)	(952)	(1 227)	(1 528)	(1 831)	(2 143)
Capital Expenditures	(262)	4	347	279	140	152	162	(482)	(601)	(6)	282	274	428	363	467	(33)	(127)	(171)	(185)
Equity	1%	5%	2%	2%	2%	2%	2%	1%	1%	0%	0%	-1%	-2%	-2%	-3%	-3%	-4%	-5%	-6%
Interest Coverage	0.10	0.02	(0.07)	(0.04)	(0.03)	0.00	(0.02)	(0.05)	(0.08)	(0.11)	(0.11)	(0.11)	(0.12)	(0.09)	(0.07)	(0.18)	(0.22)	(0.24)	(0.28)
Capital Coverage	0.14	0.09	(0.12)	(0.37)	(0.25)	(0.10)	(0.39)	(0.33)	(0.29)	(0.12)	(0.07)	(0.09)	(0.32)	(0.60)	(0.14)	(0.20)	(0.09)	0.06	(0.46)

* The 3.50% electric rate increase in 2014 was implemented effective May 1, 2013. In accordance with PUB Order 43/13, 1.5% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.

PUB/MH I-12

Reference: Appendix 1, Financial Targets

a) Please update PUB/MH II-41 from the 2012 GRA revised based on MH13-1.

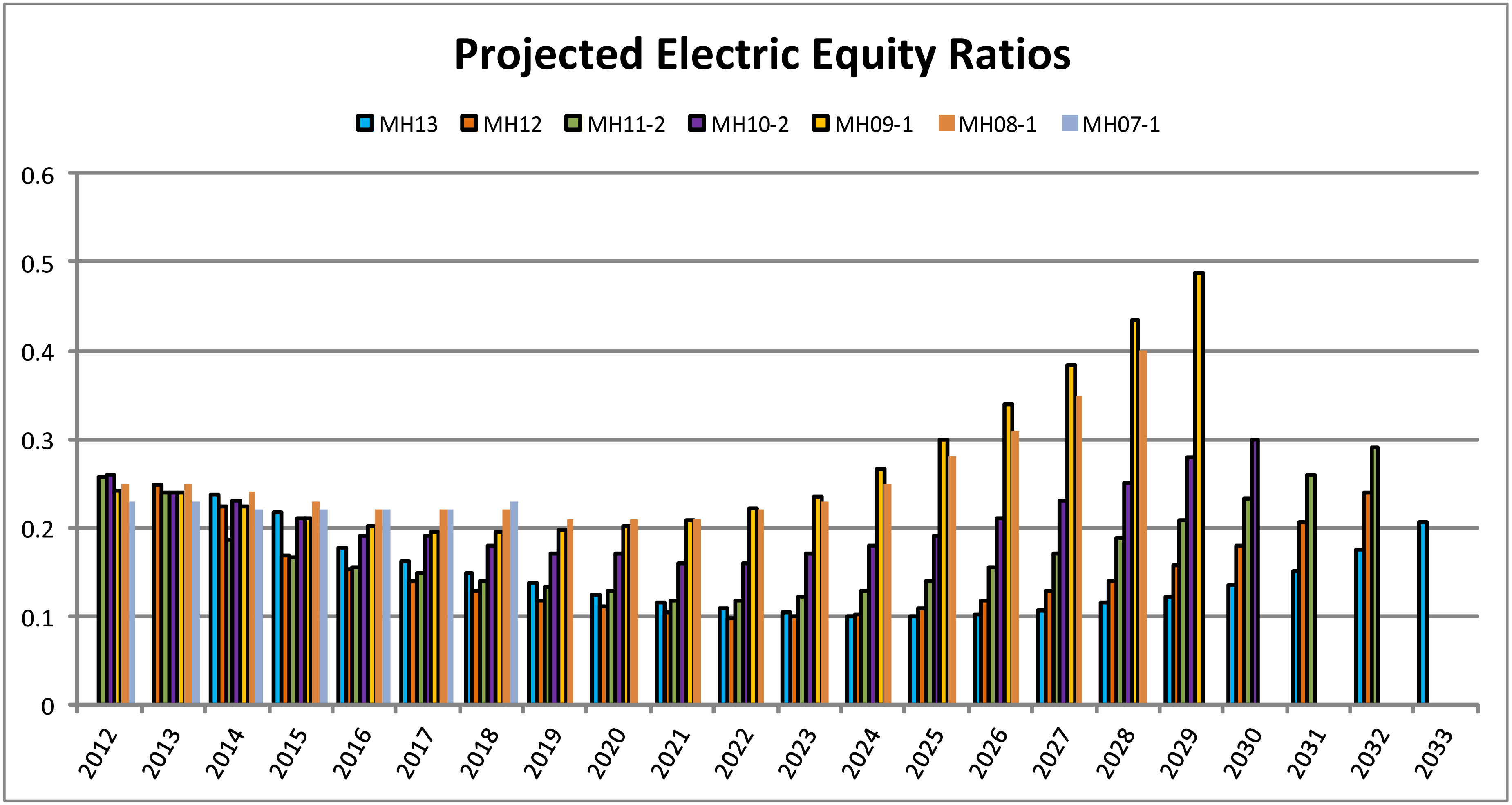
ANSWER:

Please see the following tables for the requested information.

Projected Electric Financial Ratios

	MH13			MH12			MH11-2		
	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio
2014	24%	1.20	1.03	22%	1.10	0.89	19%	1.11	1.13
2015	22%	1.09	0.86	17%	1.07	0.77	17%	1.09	1.15
2016	18%	1.02	0.78	15%	1.09	0.90	15%	1.15	1.43
2017	16%	1.02	0.84	14%	1.06	1.21	15%	1.17	1.54
2018	15%	0.99	1.12	13%	1.02	1.37	14%	1.12	1.48
2019	14%	0.94	1.01	12%	0.94	1.11	13%	1.02	1.29
2020	12%	0.97	1.14	11%	0.99	1.53	13%	1.06	1.46
2021	12%	0.94	1.16	10%	0.99	1.49	12%	0.96	1.43
2022	11%	0.96	1.32	10%	1.04	1.61	12%	1.08	1.86
2023	10%	1.00	1.51	10%	1.11	1.63	12%	1.14	1.93
2024	10%	1.04	1.68	10%	1.15	1.75	13%	1.19	1.99
2025	10%	1.08	1.82	11%	1.19	1.91	14%	1.26	2.04
2026	10%	1.10	1.89	12%	1.22	2.21	15%	1.28	2.36
2027	11%	1.16	2.20	13%	1.25	2.80	17%	1.26	2.32
2028	11%	1.15	2.33	14%	1.22	2.47	19%	1.33	2.57
2029	12%	1.14	2.40	16%	1.32	2.60	21%	1.38	2.59
2030	13%	1.22	2.68	18%	1.44	2.77	23%	1.46	2.65
2031	15%	1.29	2.94	20%	1.53	2.88	26%	1.49	3.34
2032	18%	1.42	3.34	24%	1.70	3.80	29%	1.63	3.00
2033	21%	1.56	3.72	NA	NA	NA	NA	NA	NA

	MH10-2			MH09-1		
	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio	Equity Ratio	Interest Coverage Ratio	Capital Coverage Ratio
2014	23%	1.28	1.29	22%	1.19	1.25
2015	21%	1.19	1.33	21%	1.15	1.53
2016	19%	1.26	1.62	20%	1.30	1.89
2017	19%	1.28	1.74	20%	1.28	1.87
2018	18%	1.20	1.66	20%	1.23	1.96
2019	17%	1.09	1.49	20%	1.22	2.21
2020	17%	1.14	1.68	20%	1.22	2.71
2021	16%	1.00	1.51	21%	1.24	2.32
2022	16%	1.16	1.95	22%	1.36	2.26
2023	17%	1.22	1.95	24%	1.45	2.30
2024	18%	1.25	1.99	26%	1.59	2.59
2025	19%	1.32	2.10	30%	1.66	2.50
2026	21%	1.29	2.20	34%	1.79	2.81
2027	23%	1.35	2.34	38%	1.90	2.95
2028	25%	1.43	2.56	43%	2.05	3.19
2029	28%	1.51	2.60	49%	2.22	3.19
2030	30%	1.59	2.65	NA	NA	NA
2031	NA	NA	NA	NA	NA	NA
2032	NA	NA	NA	NA	NA	NA
2033	NA	NA	NA	NA	NA	NA


Projected Electric Equity Ratios
MH13
MH12
MH11-2
MH10-2
MH09-1
MH08-1
MH07-1
0.6
0.5
0.4
0.3
0.2
0.1
0
2012
2013
2014
2015
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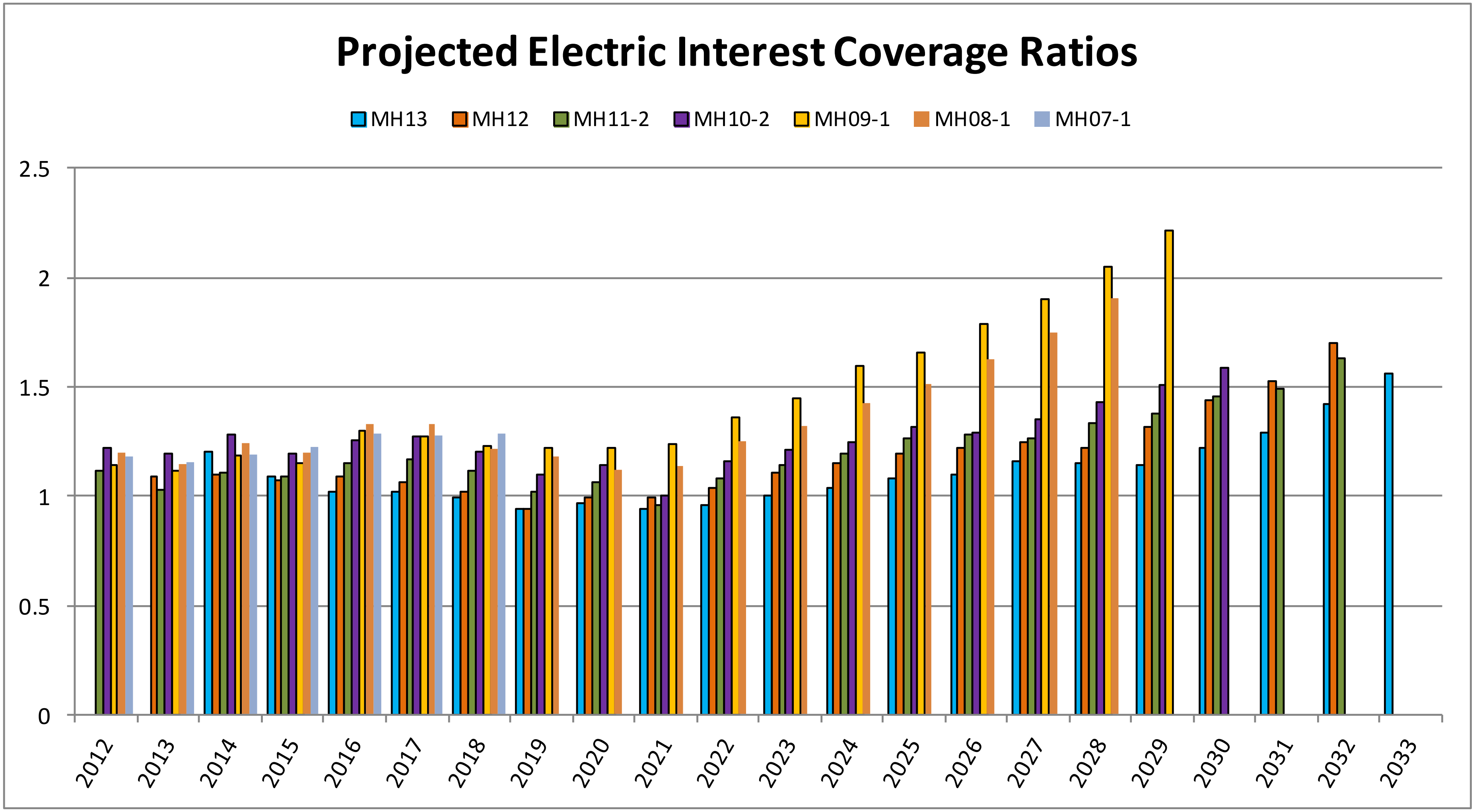
Projected Electric Interest Coverage Ratios
MH13
MH12
MH11-2
MH10-2
MH09-1
MH08-1
MH07-1
2.5
2
1.5
1
0.5
0
2012
2013
2014
2015
2016
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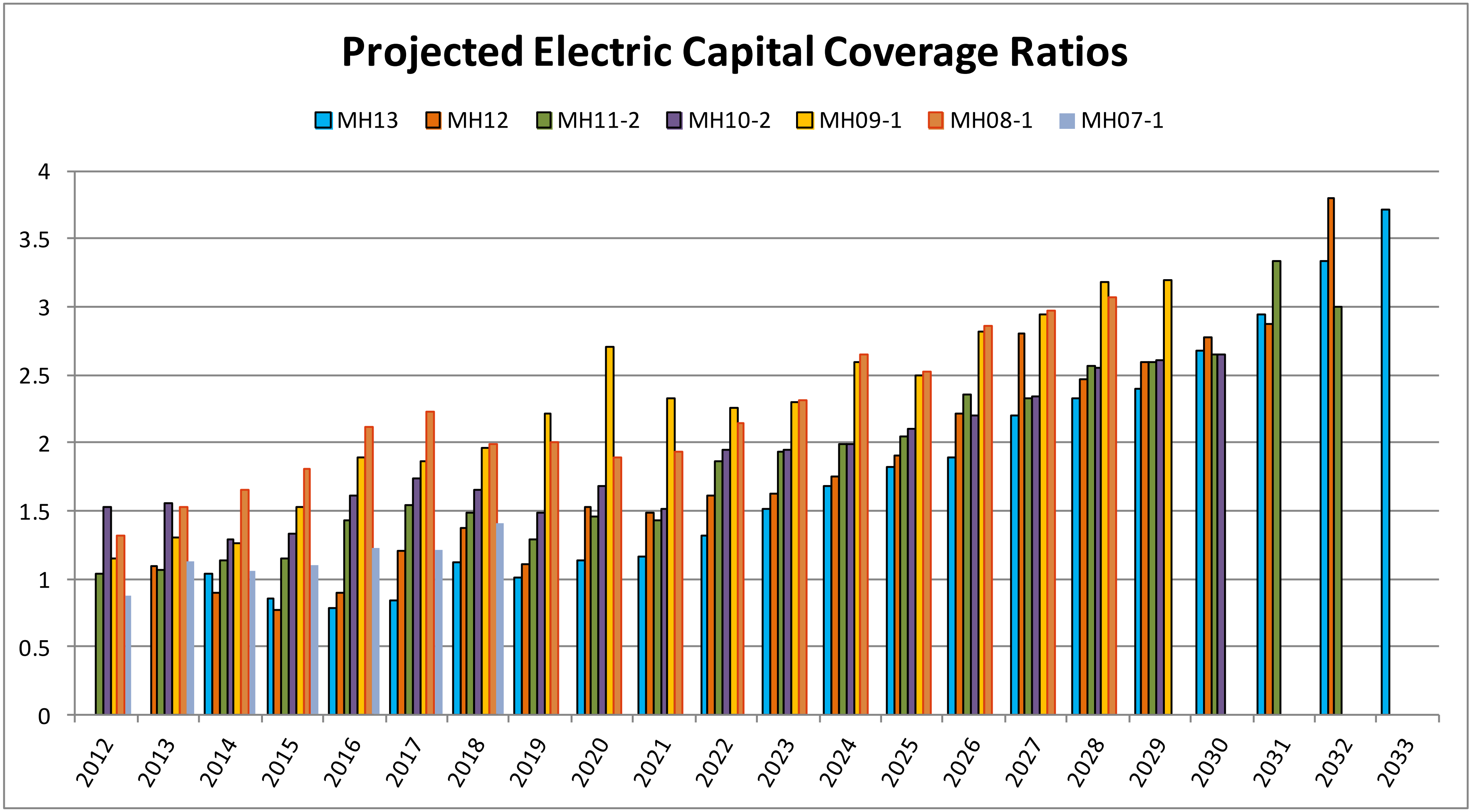
Projected Electric Capital Coverage Ratios
MH13
MH12
MH11-2
MH10-2
MH09-1
MH08-1
MH07-1
4
3.5
3
2.5
2
1.5
1
0.5
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
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2022
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2031
2032
2033

PUB/MH I-12

Reference: Appendix 1, Financial Targets

b) Please update PUB/MH II-46 from the 2012 GRA revised based on MH13-1.

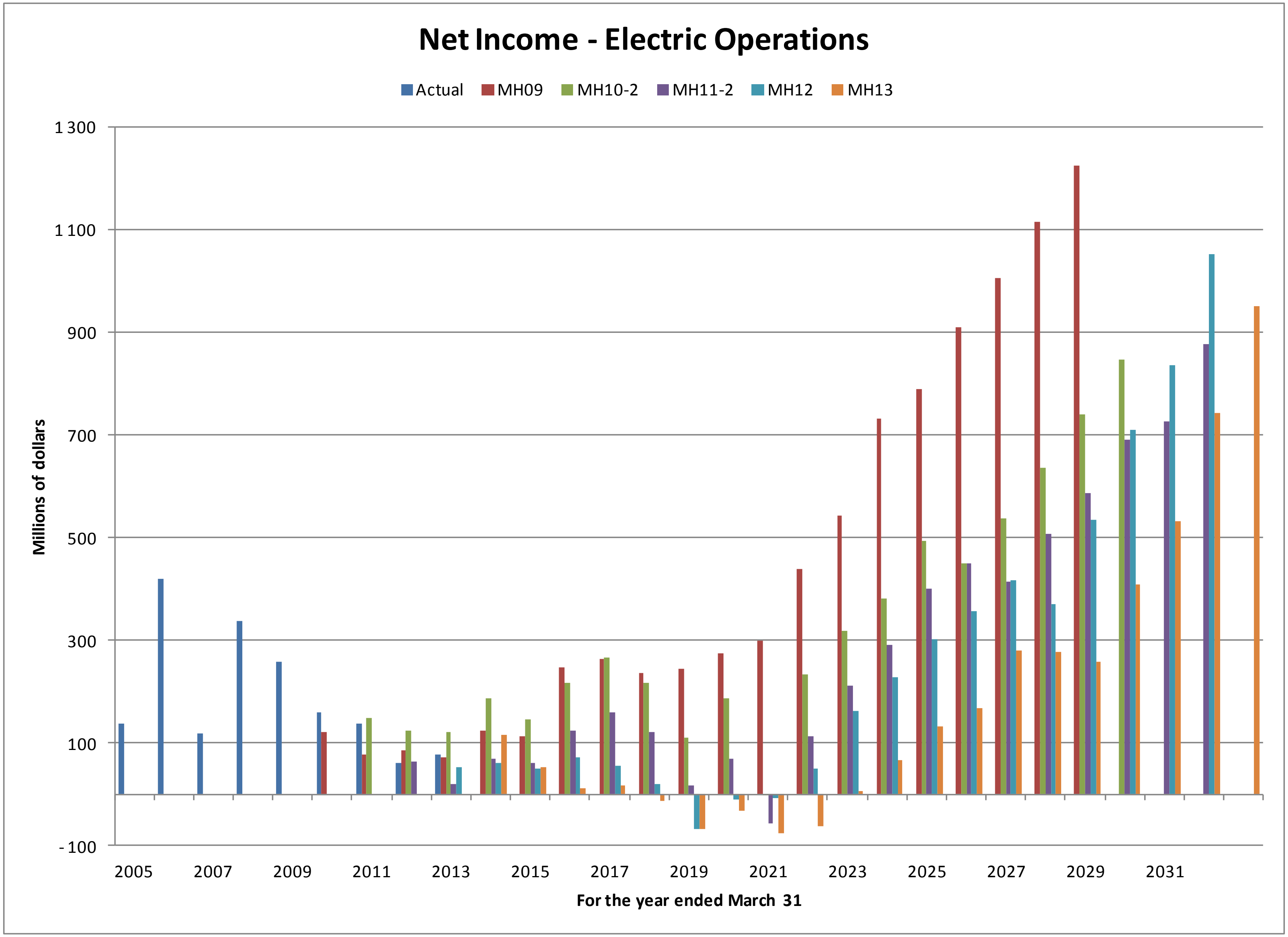
ANSWER:

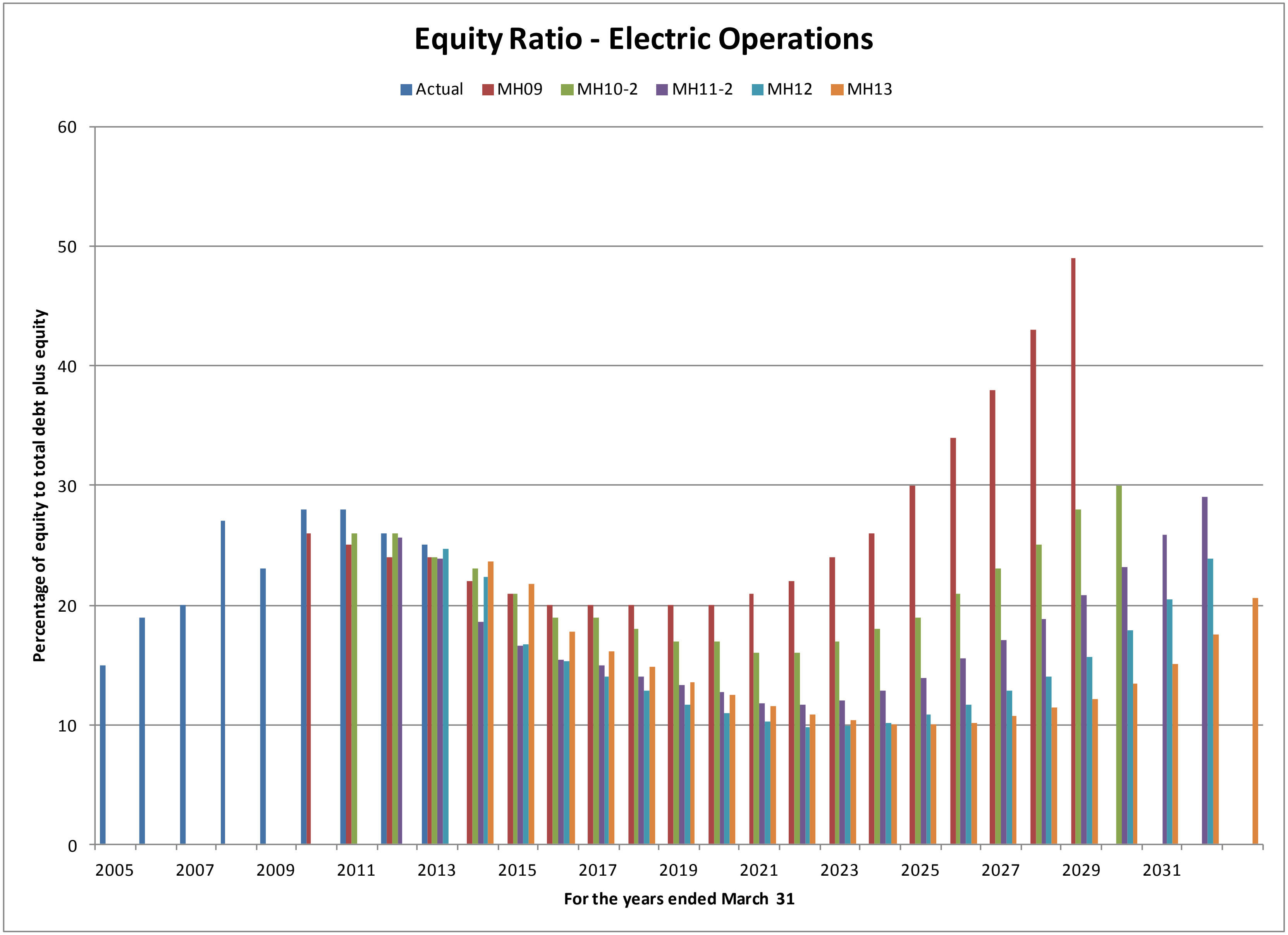
Please see the following tables for the requested information.

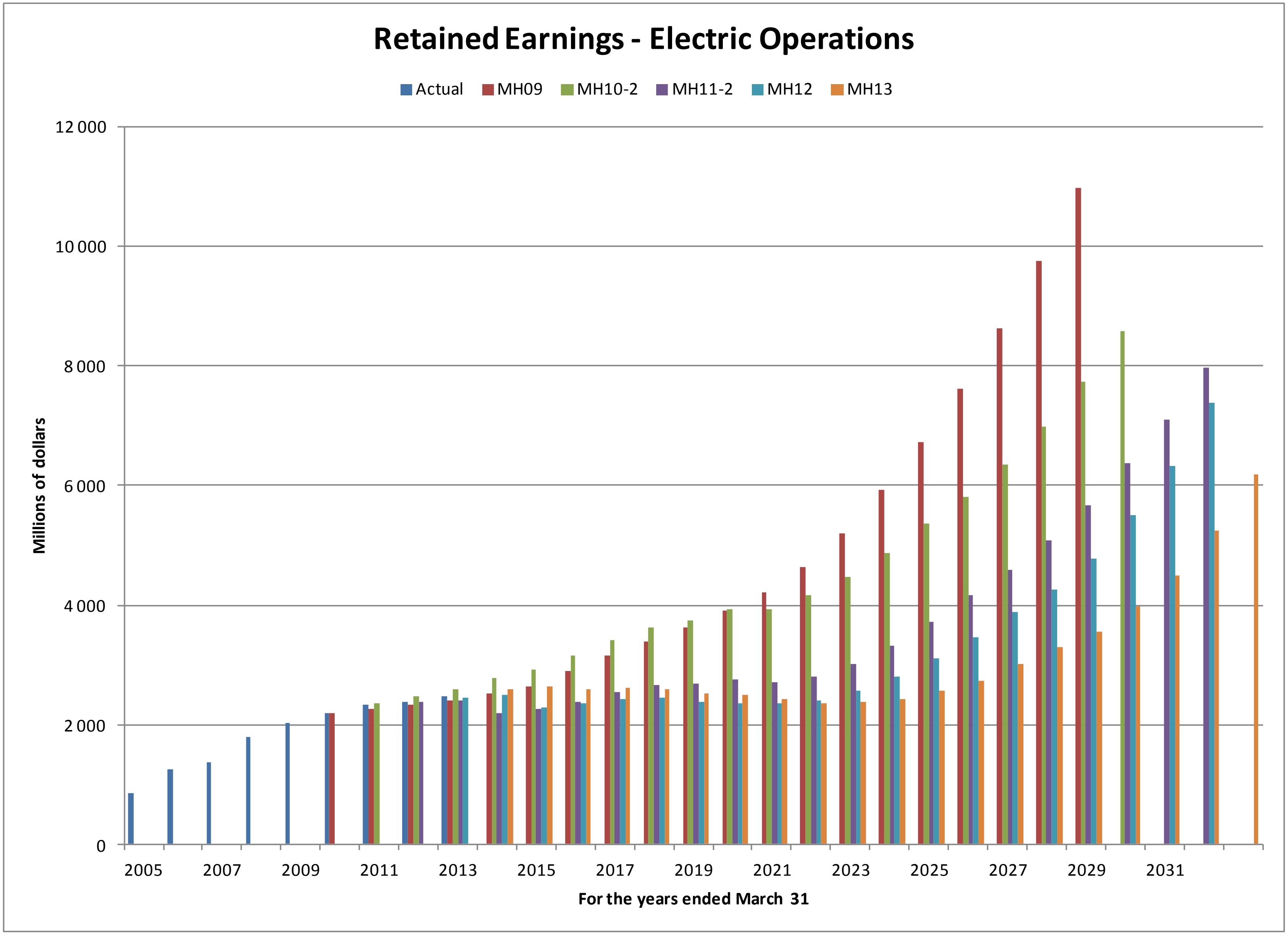
Fiscal Year Ending	Net Income - Electric Operations ($Millions)					
	Actual	MH09	MH10-2	MH11-2	MH12	MH13
2005	137					
2006	420					
2007	119					
2008	337					
2009	258					
2010	160	121				
2011	138	78	149			
2012	62	87	125	64		
2013	78	72	121	20	53	
2014		125	187	68	60	116
2015		113	145	62	50	55
2016		248	219	124	73	12
2017		263	267	159	57	19
2018		235	218	121	19	(12)
2019		244	111	18	(68)	(67)
2020		276	187	70	(9)	(31)
2021		299	(1)	(57)	(7)	(75)
2022		439	233	113	52	(60)
2023		544	319	213	163	6
2024		732	382	291	228	68
2025		791	493	402	301	133
2026		911	449	450	358	168
2027		1 005	538	415	418	281
2028		1 116	637	507	370	277
2029		1 224	741	588	534	259
2030			848	691	710	408
2031				726	835	532
2032				878	1 054	742
2033						952

Fiscal Year Ending	Equity Ratio - Electric Operations (Percentage equity to total debt plus equity)					
	Actual	MH09	MH10-2	MH11-2	MH12	MH13
2005	15					
2006	19					
2007	20					
2008	27					
2009	23					
2010	28	26				
2011	28	25	26			
2012	26	24	26	26		
2013	25	24	24	24	25	
2014		22	23	19	22	24
2015		21	21	17	17	22
2016		20	19	15	15	18
2017		20	19	15	14	16
2018		20	18	14	13	15
2019		20	17	13	12	14
2020		20	17	13	11	12
2021		21	16	12	10	12
2022		22	16	12	10	11
2023		24	17	12	10	10
2024		26	18	13	10	10
2025		30	19	14	11	10
2026		34	21	15	12	10
2027		38	23	17	13	11
2028		43	25	19	14	11
2029		49	28	21	16	12
2030			30	23	18	13
2031				26	20	15
2032				29	24	18
2033						21

Fiscal Year Ending	Retained Earnings - Electric Operations ($Millions)					
	Actual	MH09	MH10-2	MH11-2	MH12	MH13
2005	845					
2006	1 262					
2007	1 378					
2008	1 784					
2009	2 028					
2010	2 190	2 183				
2011	2 328	2 261	2 355			
2012	2 390	2 331	2 480	2 391		
2013	2 468	2 403	2 598	2 411	2442	
2014		2 528	2 784	2 203	2502	2584
2015		2 641	2 930	2 265	2295	2638
2016		2 889	3 148	2 389	2368	2592
2017		3 153	3 415	2 548	2425	2611
2018		3 388	3 634	2 669	2444	2599
2019		3 632	3 744	2 687	2376	2533
2020		3 908	3 931	2 757	2368	2502
2021		4 207	3 930	2 700	2361	2427
2022		4 645	4 163	2 814	2413	2366
2023		5 190	4 482	3 026	2576	2372
2024		5 922	4 864	3 317	2804	2440
2025		6 713	5 357	3 719	3105	2572
2026		7 623	5 806	4 170	3463	2741
2027		8 629	6 344	4 584	3881	3022
2028		9 745	6 981	5 092	4251	3299
2029		10 969	7 722	5 679	4785	3558
2030			8 570	6 370	5495	3967
2031				7 096	6330	4499
2032				7 974	7384	5241
2033						6193


Net Income - Electric Operations
Actual
MH09
MH10-2
MH11-2
MH12
MH13
1 300
1 100
900
700
500
300
100
- 100
Millions of dollars
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
For the year ended March 31


Equity Ratio - Electric Operations
Actual
MH09
MH10-2
MH11-2
MH12
MH13
Percentage of equity to total debt plus equity
0
10
20
30
40
50
60
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
For the years ended March 31


Retained Earnings - Electric Operations
Actual
MH09
MH10-2
MH11-2
MH12
MH13
12 000
10 000
8 000
6 000
4 000
2 000
0
Millions of dollars
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
For the years ended March 31

PUB/MH I-13

Reference: Appendix 1, Page 28 Capital Expenditure Forecast

a) Please provide a comparative analysis of the Major Generation and Transmission projects forecast in CEF13 with CEF12 and CEF09.

ANSWER:

Please see the following tables for the requested information.

Major Generation and Transmission (In Millions of Dollars)	CEF09	CEF12	CEF13	From CEF09 to CEF12	From CEF09 to CEF12 Change Explanation	From CEF12 to CEF13	From CEF12 to CEF13 Change Explanation
Wuskwatim	1 591	1 772	1 769	181	In-service date deferred 9 months from September 2011. Addition of a staffhouse.	(3)	Cost flow revision & decrease in costs to completion.
Herblet Lake Transmission	93	77	76	(16)	Project budget decreased due to favourable contract bid for clearing the right-of-way & construction of transmission line H75P. In-service date advanced 2 months from September 2011.	(1)	Cost flow revision & decrease in costs to completion.
Keeyask G.S.	4 592	6 220	6 220	1 628	In-service date deferred 11 months from December 2018. A review of the cost estimate in summer of 2012 resulted in an inclusion of a management reserve for labour cost and inflation risks to better address uncertainty related to future costs.	-	No change.
Conawapa G.S.	6 325	10 192	10 492	3 867	In-service date deferred 3 years from May 2022. A review of the cost estimate in summer of 2012 resulted in an inclusion of a management reserve for labour cost and inflation risks to better address uncertainty related to future costs.	300	In-service date deferred 1 year from May 2025. Addition of work supporting environmental assessment and EIS submission and 1% PST increase.
Kelsey G.S.	190	302	302	112	Project scope changed to include rehabilitation of all intake gates and modifications to all draft tubes, an 8000 hr inspection and construction camp expansion, sewer and water improvements and supply contracts. In-service date deferred 2 years & 8 months from March 2012.	-	No change to project costs. In-service date advanced 3 months from November 2014.
Kettle G.S.	76	166	166	90	Scope changed to include stator replacements for units 1-3, along with outage related opportunity work of units 1-4.	-	No change to project costs. In-service date deferred 3 years & 5 months from October 2022.
Pointe du Bois Spillway	318	560	560	242	Estimate increased to reflect updated design work. In-service date advanced 7 months from October 2014.	-	No change.

Major Generation and Transmission (In Millions of Dollars)	CEF09	CEF12	CEF13	From CEF09 to CEF12	From CEF09 to CEF12 Change Explanation	From CEF12 to CEF13	From CEF12 to CEF13 Change Explanation
Pointe du Bois Transmission	86	86	114	-	No change to project costs. In-service date deferred 4 months from May 2014.	28	Increased the project budget as a result of 2 factors: a change in concept for replacement of the four 66kV lines from Pointe du Bois to Rover Stations & higher estimated costs for the Stafford Station Rebuild and Point du Bois Bank 7 Replacement. In-service date deferred 3 years and 3 months from September 2014.
Pointe du Bois Rebuild		1 538	1 538	1 538	New Item.	-	No change.
Gillam Redevelopment		367	367	367	New Item.	-	No change.
Bipole III	2 248	3 280	3 341	1 032	Increased to incorporate base estimate reviews on property, design and construction of the Transmission Line, Converter Stations and Collector Lines with an inclusion of contingency, increased escalation and capitalized interest for these revised costs.	61	Establishment of a Community Development Initiative to provide benefits to First Nations, Community Councils, Rural Municipalities and Incorporated Towns and Villages within the vicinity of the Bipole III project.
Riel 230 kV Station	268	268	330	-	No change.	62	Increased the project budget following a detailed review of the project scope and estimate including incorporation of award values of all the major contracts. In-service date deferred 5 months from May 2014.
Firm Import Upgrades	5	20	20	15	Project scope changes as determined by a more detailed facilities study completed by system planning. In-service date deferred 2 years and 5 months from March 2012.	-	No change to project costs. In-service date deferred 1 year from August 2014.
500 KV Dorsey U.S. Border	205	205	350	-	No change to project costs. In-service date deferred 2 years from May 2018.	145	Costs were increased for additional line length to run through South Loop to Riel Station before heading south to the US border. Scope was increased to include a phase shifting transformer at Glenboro Station and the required transmission line re-alignment. In-service date advanced 7 months from May 2020.
Additional North-South Transmission		396	475	396	New Item.	79	Cost flow revision only, no change in base project costs.

PUB/MH I-13

Reference: Appendix 1, Page 28 Capital Expenditure Forecast

b) Please provide an annual comparative analysis of the Base Capital spending forecast in CEF13 with CEF12 and explain the changes over the twenty year forecast.

ANSWER:

Please see CEF13, which has been attached. The changes in major capital and base capital spending between CEF13 and CEF12 are explained on pages 19 to 34.

February 2014

Capital Expenditure Forecast (CEF13)

2013/14 - 2032/33

Corporate Controller Division
Finance & Regulatory

Manitoba Hydro

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

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2.0 Project Summaries

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

Section 1

Overview

Capital Expenditure Forecast Summary
Comparison to CEF12
Capital Expenditure Forecast Summary Table

1.0 Overview

The Capital Expenditure Forecast (CEF13) is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity and natural gas service requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the province. Expenditures included in the Capital Expenditure Forecast will provide for an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner.

The Capital Expenditure Forecast is comprised of a number of specifically identified large projects or "major items" as well as numerous unspecified smaller projects referred to as "base items." Major items are normally greater than $50 million in total cost and the construction period on each major item usually extends beyond one year. Base capital expenditure items typically represent sustaining capital requirements to meet electricity and natural gas service replacements and expansions throughout the province. All major and base capital projects are subjected to a rigorous review and approval process before being included in the Capital Expenditure Forecast. The Capital Expenditure Forecast also includes general provisions, beginning in 2021/22, for expenditures that are necessary to maintain the existing generating station, transmission and distribution systems but for which detailed planning and engineering has not been completed nor received specific project approval.

Base capital targets established for fiscal years 2013/14 through 2016/17 in CEF13 considered increased requirements for aging infrastructure based upon asset condition assessment reports. Beginning in 2017/18, base capital targets are set at $500 million per year and escalated at 1% per year thereafter.

Capital Expenditure Forecast Summary

The CEF13 totals $34 442 million for the twenty year period to 2032/33. Expenditures for Major New Generation & Transmission (MNG&T) total $23 180 million, with the balance of $11 262 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and ongoing efficiency improvements.

Comparison to CEF12

The CEF13 for the twenty year period to 2032/33 totals $34 442 million compared to $33 526 million for the same twenty year period included in last year's Capital Expenditure Forecast (CEF12).

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
CEF12	1 895	2 042	2 112	2 258	2 219	1 913	1 718	1 854	2 356	2 323	20 689
Incr (Decr)	(248)	20	371	285	140	148	160	(482)	(601)	(4)	(211)
CEF13	1 647	2 062	2 483	2 543	2 358	2 061	1 878	1 372	1 755	2 319	20 478

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
CEF12	2 077	1 883	1 615	1 471	928	1 127	1 047	994	859	834	33 526
Incr (Decr)	282	279	432	367	470	(29)	(125)	(166)	(179)	(204)	916
CEF13	2 359	2 162	2 048	1 838	1 399	1 098	922	828	680	630	34 442

The following table provides a summary of the major changes to CEF13.

	Total Projected Cost	**20 Year Increase (Decrease)**
	($ Millions)	
Electric Demand Side Management*	NA	367
Conawapa - Generation	10 492	324
Transmission Line Upgrades for NERC Alert	151	151
Dorsey - US Border New 500kV Transmission Line	350	146
Electric Base Capital	NA	136
Gas Demand Side Management*	NA	71
Keeyask - Generation	6 220	64
Bipole III - Converter Stations	1 829	63
Riel 230/500kV Station	330	63
Community Development Initiative	61	61
Pointe du Bois Spillway Replacement	560	60
Wuskwatim - Generation	1 449	52
Dawson Road Station - 115/24kV Station	52	52
St. Vital Station - 115/24kV Station	51	51
Gas Base Capital	NA	45
Other Changes	NA	(77)
Sub-total		1 629
CEF12 Overhead Adjustment	NA	(713)
		916

*Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under an interim standard that continues to permit rate regulated accounting.

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	44.8	23.8	12.1	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	2.3	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	0.3	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	350.1	471.0	639.3	865.1	1 111.4	942.3	789.5	282.4	129.3	-	5 580.2
Conawapa - Generation	10 491.5	69.8	70.1	125.9	99.4	240.6	308.1	387.5	432.5	1 061.6	1 722.1	4 517.5
Kelsey Improvements & Upgrades	301.7	16.0	2.2	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	3.2	7.7	23.7	17.3	1.0	31.7	29.5	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	260.5	125.3	5.5	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	12.7	8.6	12.3	21.9	7.4	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	0.5	2.2	2.7
Gillam Redevelopment and Expansion Program (GREP)	366.5	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7	26.8	256.0
Bipole III - Transmission Line	1 259.9	66.2	265.9	381.9	263.7	195.2	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	179.0	262.6	493.2	410.2	181.5	127.4	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	28.8	63.5	46.2	37.7	8.5	-	-	-	-	-	184.6
Community Development Initiative	60.8	53.9	2.2	2.0	1.8	0.9	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	74.1	40.8	0.7	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	0.0	10.8	8.9	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	0.4	3.8	29.7	101.1	58.7	63.5	91.7	0.1	-	-	349.0
St. Joseph Wind Transmission	10.0	0.0	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	28.1	25.3	24.6	23.9	22.6	21.7	19.9	18.9	18.8	18.7	222.4
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	2.8	33.0	33.6	34.3	103.7
Additional North South Transmission	475.0	-	-	-	-	-	-	-	4.1	4.4	51.6	60.2
Target Adjustment (Cost Flow)	NA	(119.0)	(33.9)	(46.0)	(8.2)	0.7	33.6	20.9	56.8	(42.0)	(62.1)	(199.3)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 071.1**	**1 376.5**	**1 790.2**	**1 864.4**	**1 858.1**	**1 556.0**	**1 368.1**	**856.8**	**1 234.8**	**1 793.6**	**14 769.6**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	14.2	8.0	5.0	21.9	30.2	27.0	16.0	-	-	-	122.3
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	-	-
Slave Falls Major Overhauls	126.1	-	0.2	0.9	5.3	26.6	30.3	31.8	26.9	4.2	-	126.1
Water Licenses & Renewals	56.8	7.6	7.0	7.0	6.5	2.4	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	10.2	10.3	15.3	21.7	19.5	20.4	24.2	19.5	17.1	9.6	167.9
Great Falls Unit 4 Overhaul	53.6	4.6	16.5	11.9	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	6.0	0.4	17.5	7.8	31.7
		36.7	42.1	40.2	55.3	78.6	77.7	78.0	46.7	38.8	17.5	511.6
Transmission												
Rockwood East 230/115kV Station	53.3	13.1	29.1	8.6	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	15.2	30.0	17.2	0.0	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	1.2	3.0	34.9	18.1	1.6	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	1.1	8.9	9.0	9.1	23.7	24.2	24.7	25.1	25.6	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	6.7	7.9	8.9	8.5	5.9	3.4	0.8	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	0.4	16.5	33.2	9.9	3.5	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	2.1	13.3	23.1	57.4	58.5	59.6	213.9
		36.2	71.0	78.4	36.0	35.2	73.6	57.9	85.5	83.6	85.1	642.6
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	2.1	20.0	25.6	16.1	1.3	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	0.1	0.3	3.0	20.0	20.0	7.9	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	0.0	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	51.8
Burrows New 66/12kV Station	54.7	8.7	5.1	-	-	-	-	-	-	-	-	13.8
		10.9	27.9	29.1	39.1	37.8	27.9	9.3	-	-	-	182.1
MAJOR CAPITAL TOTAL		**83.8**	**141.1**	**147.7**	**130.5**	**151.7**	**179.2**	**145.1**	**132.3**	**122.4**	**102.6**	**1 336.3**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Base Capital												
Electric												
Generation Operations	NA	98.2	94.2	87.7	101.8	63.9	59.6	67.2	70.5	73.2	77.8	794.1
Transmission	NA	104.1	114.9	126.1	112.0	70.3	65.6	73.9	77.5	80.5	85.6	910.6
Customer Service & Distribution	NA	175.4	207.6	211.8	229.2	143.8	134.3	151.2	158.6	164.8	175.2	1 751.9
Customer Care & Energy Conservation	NA	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	33.6
Human Resources & Corporate Services	NA	61.4	75.7	54.8	54.8	34.4	32.1	36.2	37.9	39.4	41.9	468.6
Finance & Regulatory	NA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2
		442.4	495.8	483.7	501.3	316.0	295.2	332.1	348.3	361.8	384.4	3 961.0
Gas												
Customer Service & Distribution	NA	35.7	34.9	49.0	34.9	22.3	21.2	24.4	26.1	27.7	30.0	306.2
Customer Care & Energy Conservation	NA	13.7	13.4	12.3	12.1	10.1	9.3	8.5	8.5	8.4	8.5	104.8
		49.4	48.3	61.3	47.0	32.4	30.6	32.8	34.6	36.1	38.5	411.0
BASE CAPITAL TOTAL		**491.8**	**544.1**	**545.1**	**548.3**	**348.3**	**325.8**	**364.9**	**382.9**	**397.9**	**422.9**	**4 372.0**
CONSOLIDATED CEF13 TOTAL		**1 646.6**	**2 061.7**	**2 482.9**	**2 543.1**	**2 358.1**	**2 061.0**	**1 878.1**	**1 372.0**	**1 755.1**	**2 319.1**	**20 477.9**
ELECTRIC CAPITAL TOTAL		**1 597.2**	**2 013.4**	**2 421.6**	**2 496.1**	**2 325.7**	**2 030.5**	**1 845.3**	**1 337.4**	**1 719.1**	**2 280.6**	**20 066.8**
GAS CAPITAL TOTAL		**49.4**	**48.3**	**61.3**	**47.0**	**32.4**	**30.6**	**32.8**	**34.6**	**36.1**	**38.5**	**411.0**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	-	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	-	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 580.2
Conawapa - Generation	10 491.5	1 700.2	1 428.7	1 228.1	920.1	371.2	65.0	-	-	-	-	10 230.8
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	-	-	-	-	-	-	-	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	-	1 538.3
Gillam Redevelopment and Expansion Program (GREP)	366.5	32.3	32.1	34.0	11.9	-	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	184.6
Community Development Initiative	60.8	-	-	-	-	-	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	-	-	-	-	-	-	-	-	-	-	349.0
St. Joseph Wind Transmission	10.0	-	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	19.1	18.7	17.9	16.2	16.0	16.3	16.6	16.9	17.3	17.6	395.1
Generating Station Improvements & Upgrades	NA	35.0	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	373.8
Additional North South Transmission	475.0	29.8	49.9	85.7	116.8	132.7	-	-	-	-	-	475.0
Target Adjustment (Cost Flow)	NA	(3.9)	22.6	13.3	23.8	49.5	34.0	20.2	11.1	17.1	6.2	(5.5)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 828.5**	**1 625.5**	**1 506.1**	**1 291.6**	**846.5**	**540.2**	**358.9**	**258.7**	**105.2**	**49.6**	**23 180.3**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	122.3
Jenpeg Overhaul Program	115.9	2.7	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	115.9
Slave Falls Major Overhauls	126.1	-	-	-	-	-	-	-	-	-	-	126.1
Water Licenses & Renewals	56.8	-	-	-	-	-	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	7.4	3.3	0.2	0.1	-	-	-	-	-	-	178.9
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	18.8	-	-	-	-	-	-	-	-	-	50.4
		28.8	6.3	21.7	21.8	23.3	1.2	45.4	(3.4)	0.6	-	657.3
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	-	-	-	-	-	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	19.8	-	-	-	-	-	-	-	-	-	233.7
		19.8	-	-	-	-	-	-	-	-	-	662.4
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	-	-	-	-	-	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	13.8
		-	-	-	-	-	-	-	-	-	-	182.1
MAJOR CAPITAL TOTAL		**48.6**	**6.3**	**21.7**	**21.8**	**23.3**	**1.2**	**45.4**	**(3.4)**	**0.6**	**-**	**1 501.8**

Manitoba Hydro
Consolidated Capital Expenditure Forecast (CEF13)
For the Years 2013/14 – 2032/33

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Base Capital												
Electric												
Generation Operations	NA	71.7	83.9	81.5	81.1	81.0	83.7	76.5	84.0	84.5	84.6	1 606.6
Transmission	NA	78.8	92.3	89.7	89.3	89.1	92.1	84.2	92.4	93.0	93.1	1 804.4
Customer Service & Distribution	NA	251.7	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	4 506.1
Customer Care & Energy Conservation	NA	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	74.6
Human Resources & Corporate Services	NA	38.6	45.1	43.9	43.7	43.6	45.0	41.2	45.2	45.5	45.5	905.9
Finance & Regulatory	NA	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4.8
		444.7	486.9	477.0	481.6	485.2	510.8	474.5	524.8	525.3	530.6	8 902.4
Gas												
Customer Service & Distribution	NA	28.3	33.7	33.5	34.0	34.7	36.6	34.1	38.2	39.3	40.2	658.8
Customer Care & Energy Conservation	NA	9.1	9.2	9.3	9.4	9.1	9.2	9.3	9.5	9.6	9.7	198.2
		37.4	42.9	42.8	43.4	43.8	45.8	43.5	47.7	48.9	49.9	857.0
BASE CAPITAL TOTAL		**482.1**	**529.8**	**519.7**	**525.0**	**529.1**	**556.6**	**518.0**	**572.5**	**574.1**	**580.5**	**9 759.4**
CONSOLIDATED CEF13 TOTAL		**2 359.3**	**2 161.5**	**2 047.5**	**1 838.5**	**1 398.8**	**1 098.1**	**922.3**	**827.7**	**679.9**	**630.1**	**34 441.6**
ELECTRIC CAPITAL TOTAL		**2 321.9**	**2 118.6**	**2 004.7**	**1 795.1**	**1 355.0**	**1 052.3**	**878.8**	**780.0**	**631.0**	**580.2**	**33 584.5**
GAS CAPITAL TOTAL		**37.4**	**42.9**	**42.8**	**43.4**	**43.8**	**45.8**	**43.5**	**47.7**	**48.9**	**49.9**	**857.0**




Section 2

Project Summaries

ELECTRIC OPERATIONS:

MAJOR NEW GENERATION & TRANSMISSION:

Wuskwatim - Generation

Description:
Design and build the new Wuskwatim generating station with three generators and installed capacity of approximately 200MW on the Burntwood River upstream of Thompson.

Justification:
This project increases generation for both export power purposes and domestic load requirements.

In-Service Date:
First power June 2012.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 1 448.6	$ 12.3	$ 16.2	$ -	$ -	$ -	$ -
Increase (Decrease)	-	32.6	7.6	12.1	-	-	-
Revised Forecast	$ 1 448.6	$ 44.8	$ 23.8	$ 12.1	$ -	$ -	$ -

Wuskwatim - Transmission

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities necessary to integrate the Wuskwatim generating station into the Manitoba Hydro 230kV transmission network as follows: *Transmission*: 230kV lines from Wuskwatim switching station to Thompson Birchtree station, from Wuskwatim switching station to Herblet Lake station, and from Wuskwatim generating station to Wuskwatim switching station. *Terminations*: New 230kV stations at Thompson Birchtree and Wuskwatim, new 230kV 150MVA static var compensator at Thompson Birchtree station, terminate lines into Herblet Lake and replace protection at Kelsey and Thompson Mystery Lake Road stations. *Communications*: system additions for protection of the new transmission lines and stations, including optical power ground wire on the Wuskwatim to Birchtree transmission line.

Justification:
The existing 230kV transmission system in northern Manitoba does not have sufficient capacity to accommodate the additional output of the Wuskwatim generating station. This project will increase the ability of the transmission system to carry the full output of Wuskwatim to load anywhere in Manitoba.

In-Service Date:
First Power June 2012.

Revision:
Cost flow revision and decrease in costs to completion.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 322.9	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(3.1)	2.3	-	-	-	-	-
Revised Forecast	$ 319.8	$ 2.3	$ -	$ -	$ -	$ -	$ -

Herblet Lake - The Pas 230kV Transmission

Description:
Perform environmental assessments and route selection, design and construct transmission and terminal facilities to provide firm supply to Flin Flon Cliff Lake and The Pas Ralls Island as follows: *Transmission*: 230kV line 160km from Herblet Lake to The Pas Ralls Island. *Terminations*: Extend 230kV facilities at Herblet Lake and The Pas Ralls Island stations. *Communications*: Upgrade and co-ordinate with existing Herblet Lake and The Pas facilities.

Justification:
The line is required to provide firm supply and voltage support for increasing Flin Flon and The Pas area loads. In addition, this line facilitates the transmission of power from the Wuskwatim generating station.

In-Service Date:
July 2011.

Revision:
Cost flow revision and decrease in costs to completion.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 76.6	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(0.2)	0.3	-	-	-	-	-
Revised Forecast	$ 76.4	$ 0.3	$ -	$ -	$ -	$ -	$ -

Keeyask - Generation

Description:
Design and build the Keeyask generating station with seven generators and nominal capacity of 695MW on the Nelson River downstream of the Kelsey generating station. Project costs also include activities necessary to obtain approval and community support to proceed with the construction of the future generating station. These costs are comprised of extensive First Nations and other community consultations, pre-project training, joint venture business developments, environmental studies, impact statement preparations, submissions, regulatory review processes, detailed pre-engineering requirements, acquiring all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power November 2019.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 6 220.1	$ 339.0	$ 405.1	$ 636.5	$ 883.9	$ 1 132.1	$ 2 119.6
Increase (Decrease)	-	11.0	65.9	2.8	(18.8)	(20.7)	23.8
Revised Forecast	$ 6 220.1	$ 350.1	$ 471.0	$ 639.3	$ 865.1	$ 1 111.4	$ 2 143.4

Conawapa - Generation

Description:
Design and build the Conawapa generating station with ten generators and nominal capacity of 1 485MW on the Nelson River downstream of the Limestone generating station. Project costs also include activities associated with extensive First Nations and other community consultations, pre-project training, environmental studies, impact statement preparations, submissions, regulatory review processes, acquiring all necessary licensing, improvements to access roadways, and detailed pre-engineering required to obtain a license and all necessary approvals to construct the Conawapa generating station.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power May 2026.

Revision:
In-service deferred one year from May 2025. Increased costs for additional work supporting environmental assessment and EIS submission and 1% PST increase.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$10 192.4	$ 72.0	$ 66.3	$ 118.9	$ 245.3	$ 305.1	$ 9 098.9
Increase (Decrease)	299.1	(2.3)	3.8	7.0	(146.0)	(64.5)	526.2
Revised Forecast	$10 491.5	$ 69.8	$ 70.1	$ 125.9	$ 99.4	$ 240.6	$ 9 625.1

Kelsey Improvements & Upgrades

Description:
Overhaul and uprate all seven Kelsey generating station units including the replacement of turbine runners, bottom rings, discharge rings or weld overlays, transformers, generator windings and exciters. Perform model testing to refine runner design, perform extensive intake gate rehabilitation, perform draft tube modifications, perform an 8 000 hour inspection, and upgrade rail spur and overhead crane. Upgrade transmission facilities necessary to integrate the additional Kelsey generation into the Manitoba Hydro system network.

Justification:
Rerunnering presents the best economic solution for increasing efficiency at the Kelsey generating station and for adding system capacity without flooding or requiring a new water power license. Overhauling the units will improve the unit output by up to 11MW per unit. The transmission upgrade of a portion of the Kelsey 138 and 230kV buses and the revisions to the Northern AC Cross Trip scheme are required to accommodate the 77MW of additional Kelsey output.

In-Service Date:
August 2014.

Revision:
Cost flow revision and in-service advanced three months from November 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 301.7	$ 8.9	$ 9.5	$ -	$ -	$ -	$ -
Increase (Decrease)	-	7.1	(7.3)	-	-	-	-
Revised Forecast	$ 301.7	$ 16.0	$ 2.2	$ -	$ -	$ -	$ -

Kettle Improvements & Upgrades

Description:
Rewind stator for units 5-12 and install a new stator frame, core and winding for units 1-4. Perform rotor refurbishment, excitation upgrade replacements, control and protection system replacements, mechanical systems replacements, and intake gate and wicket gate work for units 1-4.

Justification:
The stator windings at Kettle are polyester bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Re-wedging units at Kettle is an opportunity to repair isolated cases of severe slot discharge, necessary to avoid deterioration. Unit 4 requires repairs due to an incident that occurred in August 2006, where a top clamping finger on the unit broke off and fell into the air gap causing extensive damage to the windings and core.

In-Service Date:
March 2026.

Revision:
Cost flow revision and in-service date deferred three years and five months from October 2022.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 165.7	$ 4.0	$ 19.4	$ 16.0	$ 19.8	$ 16.4	$ 39.5
Increase (Decrease)	-	(0.8)	(11.7)	7.8	(2.6)	(15.3)	21.7
Revised Forecast	$ 165.7	$ 3.2	$ 7.7	$ 23.7	$ 17.3	$ 1.0	$ 61.2

Pointe du Bois Spillway Replacement

Description:
Design and build a new spillway and new concrete and earth fill dams to replace the existing spillway structures. Includes engineering and environmental studies, community consultation, obtaining regulatory approval, and de-commissioning the existing spillway.

Justification:
Pointe du Bois does not currently meet dam safety guidelines with respect to spillway capacity. A new spillway is required to meet these guidelines.

In-Service Date:
March 2014.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 559.6	$ 248.5	$ 81.0	$ 2.3	$ -	$ -	$ -
Increase (Decrease)	-	12.0	44.3	3.2	-	-	-
Revised Forecast	$ 559.6	$ 260.5	$ 125.3	$ 5.5	$ -	$ -	$ -

Pointe du Bois - Transmission

Description:
Redevelop Stafford Terminal station (formerly Scotland station), replace Bank 7 at Pointe du Bois switchyard station, salvage 66kV P lines between Pointe du Bois and Rover stations, install a 115kV transmission line between Pointe du Bois and Whiteshell stations, add Bank 8 to Pointe du Bois switchyard, install a 66kV line between Ridgeway and Rover stations, and upgrade protection at Slave Falls switchyard station.

Justification:
The 66kV lines P1, P2, P3, and P4 between Pointe du Bois and Rover stations have exceeded their expected serviceable life and pose threats to public and employee safety. The reliability of the transmission system in the Winnipeg Central area has been degraded due to the poor physical condition of these lines. In order to successfully operate the power system and continuously deliver high quality power to our customers and protect the public, the P Lines should be removed. The rebuild of Stafford station is required to address due diligence concerns, including Manitoba Hydro grounding and switching standards and public safety, and to increase Winnipeg Central capacity. This work involves converting the 138kV system to 115kV, so work at Pointe du Bois is also required.

In-Service Date:
December 2017.

Revision:
Increase the project budget as a result of two factors: a change in concept for replacement of the four 66kV lines from Pointe du Bois to Rover Stations and higher estimated costs for the Stafford Station Rebuild and Pointe du Bois Bank 7 Replacement. In-service date deferred three years and seven months from May 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 85.9	$ 14.2	$ 20.0	$ -	$ -	$ -	$ -
Increase (Decrease)	28.4	(1.5)	(11.4)	12.3	21.9	7.4	-
Revised Forecast	$ 114.3	$ 12.7	$ 8.6	$ 12.3	$ 21.9	$ 7.4	$ -

Gillam Redevelopment and Expansion Program (GREP)

Description:
Redevelop and expand the Town of Gillam infrastructure in Phases 1B, 2 and 3. Phases 2 & 3 will require further definition based on conceptual design and the requirement of Manitoba Hydro's construction of new facilities in the North.

Justification:
Redevelopment of the Town of Gillam is required to address existing operational needs and to prepare for the growth associated with new generation facilities. The GREP will improve the overall quality of infrastructure in Gillam, which will positively affect attraction and retention for existing and new generation facilities. The GREP supports Corporate initiatives to develop the hydroelectric potential of the Lower Nelson River.

In-Service Date:
March 2027.

Revision:
None.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 366.5	$ -	$ 27.0	$ 30.2	$ 30.5	$ 29.5	$ 249.2
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 366.5	$ -	$ 27.0	$ 30.2	$ 30.5	$ 29.5	$ 249.2

Bipole III - Transmission Line

Description:
Design and build a +/- 500kV HVDC transmission line of approximately 1 341km (west of Lakes Winnipegosis & Manitoba) from Riel Converter Station to Keewatinoow Converter Station. Conduct environmental impact assessment, acquire property, and obtain licensing necessary for a +/- 500kV DC transmission line and converter stations at Riel and Keewatinoow.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage. In normal steady state operation, it will also provide an increase in southern power, due to decreased line losses (approximately 76MW under full existing generation).

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 1 259.9	$ 251.3	$ 325.4	$ 320.5	$ 176.2	$ 77.9	$ -
Increase (Decrease)	-	(185.2)	(59.5)	61.5	87.5	117.2	-
Revised Forecast	$ 1 259.9	$ 66.2	$ 265.9	$ 381.9	$ 263.7	$ 195.2	$ -

Bipole III - Converter Stations

Description:
Design and build an HVDC converter station with a rating of 2 000MW at the proposed Keewatinoow site, including property acquisition costs and the Keewatinoow 230kV AC switch yard. Design and build an HVDC converter station with 2 000MW of converters at Riel, including three synchronous compensators, property acquisition costs and the Riel 230kV AC switch yard.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage.

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 1 828.5	$ 231.1	$ 408.9	$ 379.2	$ 394.3	$ 177.3	$ -
Increase (Decrease)	-	(52.1)	(146.3)	114.0	16.0	4.3	127.4
Revised Forecast	$ 1 828.5	$ 179.0	$ 262.6	$ 493.2	$ 410.2	$ 181.5	$ 127.4

Bipole III - Collector Lines

Description:
Design and construct three permanent and two temporary 230kV collector lines for the Keewatinoow Converter Station. Construct power substation for the Keewatinoow Converter Station. Design and construct the Riel and Keewatinoow electrode lines, sectionalize the 230kV transmission line R49R at Riel. Includes the property acquisition and/or easements for the collector lines and the electrode lines.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage.

In-Service Date:
October 2017.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 191.4	$ 84.0	$ 43.6	$ 30.0	$ 11.1	$ 2.0	$ -
Increase (Decrease)	-	(55.2)	19.8	16.2	26.6	6.5	-
Revised Forecast	$ 191.4	$ 28.8	$ 63.5	$ 46.2	$ 37.7	$ 8.5	$ -

Community Development Initiative

Description:
Establishment of an obligation for a Community Development Initiative to provide benefits to First Nations, Community Councils, rural Municipalities and incorporated Towns and Villages within the vicinity of the Bipole III Project.

Justification:
Manitoba Hydro is responding to community feedback seeking longer term benefits for communities in proximity to high voltage transmission facilities. These funds will be available for community development projects that benefit a broad segment of eligible communities.

In-Service Date:
October 2017.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	60.8	53.9	2.2	2.0	1.8	0.9	-
Revised Forecast	$ 60.8	$ 53.9	$ 2.2	$ 2.0	$ 1.8	$ 0.9	$ -

Riel 230/500kV Station

Description:
Conduct environmental impact assessment and obtain licensing necessary for the Riel 230/500kV station. Design and construct a 230/500kV station at the Riel site including the installation of a 230kV bus with a maximum of five Bays, the installation of a 500kV ring bus, the installation of a 230/500kV 1200MVA transformer bank using two 230kV and one 500kV breaker, and the installation of 500kV line reactors with relocating of a reactor phase from Dorsey. Install a second reactor phase from Dorsey as a spare at Riel after the Riel reactors are in-service and salvage the third reactor phase at Dorsey. Sectionalize two 230kV transmission lines R32V and R33V into Riel station using eight 230kV breakers and associated equipment resulting in two Riel-Ridgeway and two Riel-St. Vital transmission lines. Sectionalize 500kV transmission line D602F into Riel station using two 500kV breakers and associated equipment resulting in Dorsey-Riel and Riel-Forbes 500kV circuits.

Justification:
The sectionalization of the 500kV line allows power to be imported during a catastrophic Dorsey outage, as well as an alternate path for power export during a Dorsey transformer outage.

In-Service Date:
October 2014.

Revision:
Increased the project budget following a detailed review of the project scope and estimate including incorporation of award values of all the major contracts. The in-service date is delayed by five months from May 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 267.6	$ 47.3	$ 3.5	$ 2.0	$ -	$ -	$ -
Increase (Decrease)	62.4	26.8	37.3	(1.3)	-	-	-
Revised Forecast	$ 329.9	$ 74.1	$ 40.8	$ 0.7	$ -	$ -	$ -

Firm Import Upgrades

Description:
Reconductor and resag transmission lines SC25, WT34, and SM26, and replace risers and/or current transformers for stations at Whiteshell, Ridgeway, Transcona, and Parkdale.

Justification:
This project will increase to 100MW Manitoba Hydro's firm import capability from Ontario. Increasing the transmission capability will permit greater volume of energy imports during periods when additional energy may be required.

In-Service Date:
August 2015.

Revision:
Cost flow revision and in-service date deferred one year from August 2014.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 19.9	$ 11.7	$ 8.2	$ -	$ -	$ -	$ -
Increase (Decrease)	-	(11.7)	2.6	8.9	-	-	-
Revised Forecast	$ 19.9	$ -	$ 10.8	$ 8.9	$ -	$ -	$ -

Dorsey - US Border New 500kV Transmission Line

Description:
Design, construct and commission a 235km 500kV AC single-circuit transmission line from Dorsey Station to the US border. Design and install one 500kV breaker, one 150MVAr 500kV shunt reactor, one double-wye ungrounded 46kV 73.4MVAr shunt capacitor bank and associated communications and protection at Dorsey. Design and install two 500kV breakers, one 230kV breaker, two double-wye ungrounded 46kV 73.4MVAr shunt capacitor banks, a 1 200MVA 230/500kV autotransformer and associated communications and protection at Riel. Acquire property for right-of-way, conduct environmental impact assessment, conduct community consultations, obtain licensing and perform environmental monitoring for all new facilities. Design, procure and install a new 300MVA phase shifter at Glenboro Station and re-align the transmission lines at the Glenboro Station to accommodate the new transformer.

Justification:
Power sale term sheets have been negotiated with Minnesota Power (250MW) and Wisconsin Public Service (300MW). The existing tie line capacity is insufficient to accommodate the additional sales and therefore a new export line is needed. The proposed transmission facilities will increase the Manitoba to U.S. transfer capability for both export and import purposes.

In-Service Date:
October 2019.

Revision:
Costs were increased for additional line length to run through South Loop to Riel Station before heading south to the US border. Scope was increased to include a phase shifting transformer at Glenboro Station and the required transmission line re-alignment. In-service date advanced seven months from May 2020.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 204.8	$ 0.4	$ 2.0	$ 3.7	$ 25.2	$ 61.8	$ 110.5
Increase (Decrease)	145.6	0.1	1.8	26.0	75.9	(3.1)	44.8
Revised Forecast	$ 350.3	$ 0.4	$ 3.8	$ 29.7	$ 101.1	$ 58.7	$ 155.3

St. Joseph Wind Transmission

Description:
Establish a 230kV generation interconnection from Manitoba Hydro's Letellier station to the St. Joseph Wind Farm Inc.'s 138MW wind farm near St. Joseph, Manitoba. Include the upgrade of 230kV Line L2OD (Letellier Station to Drayton Station in North Dakota) and the upgrade of 230kV Line G37C.

Justification:
Manitoba Hydro and St. Joseph Windfarm Inc. signed an Interconnection & Operating Agreement (IOA) on March 18, 2010, for connection of 138MW of generation from the St. Joseph Wind Farm. The IOA requires that Manitoba Hydro install or upgrade facilities in order to provide 138MW of interconnection service.

In-Service Date:
May 2012.

Revision:
Decrease in costs.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 11.2	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(1.2)	-	-	-	-	-	-
Revised Forecast	$ 10.0	$ -	$ -	$ -	$ -	$ -	$ -

Demand Side Management

Description:
Design, implement and deliver incentive based PowerSmart conservation programs to reduce electricity consumption in Manitoba.

Justification:
The electric Demand Side Management plan is cost effective as a resource option and is included in Manitoba Hydro's Power Resource Plan (PRP). The DSM plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service.

In-Service Date:
Ongoing.

Revision:
Revisions to energy saving and expenditures for a number of programs to reflect current market information. It is assumed that upon adoption of IFRS in 2015/16, the demand side management programs will continue to be capitalized, under an interim standard that continues to permit rate-regulated accounting.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 28.0	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)		-	25.3	24.6	23.9	22.6	270.6
Revised Forecast	NA	$ 28.1	$ 25.3	$ 24.6	$ 23.9	$ 22.6	$ 270.6

MAJOR CAPITAL:

GENERATION OPERATIONS:

Pine Falls Units 1-4 Major Overhauls

Description:
Rehabilitation, replacement of and addition to various equipment such as generator re-wind, stator radial keys, breakers, cooling raditors, instrument transformers, unit control & monitoring systems, excitation system upgrades, governor upgrades, meter upgrades, and powerhouse crane refurbishment. Replace unit 1-4 turbine runners with more efficient new design runners, rebuild existing servomotors for increased wicket gate opening allowing more discharge, and rewind the generator stators utilizing modern insulating materials. Conduct a model test and up-rate study.

Justification:
Assessment of the mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation. Pine Falls consistently spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the two stator windings are in danger of failure at any time.

In-Service Date:
April 2019.

Revision:
Cost flow revision and in-service date advanced five months from September 2019.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 142.2	$ 6.8	$ 9.2	$ 27.8	$ 27.5	$ 24.5	$ 26.2
Increase (Decrease)	-	7.4	(1.2)	(22.8)	(5.6)	5.7	16.8
Revised Forecast	$ 142.2	$ 14.2	$ 8.0	$ 5.0	$ 21.9	$ 30.2	$ 43.0

Jenpeg Overhaul Program

Description:
Major overhaul of all six generating units to inspect, repair, modify, and replace components of the turbine/generator. Areas of concern include journal bearings, thrust bearings, turbine seals, servo motors, wicket gate seals and bushings, waterhead and oil head, stator and rotor, and auxiliary systems.

Justification:
A complete overhaul is required to ensure reliable operation of the units when maximum power requirements on the system are essential.

In-Service Date:
December 2031.

Revision:
In-service date deferred ten years from December 2021.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 115.9	$ -	$ -	$ 2.3	$ 2.5	$ 18.2	$ 92.9
Increase (Decrease)	-	-	-	(2.3)	(2.5)	(18.2)	23.0
Revised Forecast	$ 115.9	$ -	$ -	$ -	$ -	$ -	$ 115.9

Slave Falls Major Overhauls

Description:
Perform major overhaul for all eight units at Slave Falls generating station, including spillway improvements/ replacements, excitation upgrades, the addition of a Unit Control and Monitoring System (UCMS) Framework, access road upgrades, and a new walkway across the spillway.

Justification:
Many safety, reliability, environmental, efficiency, operational & dam safety issues have been identified relating to the Slave Falls infrastructure. Extensive repairs, modifications and/or replacements will be required to ensure the serviceability of the plant and spillway infrastructure. Economics of this work may suggest that a new spillway be constructed to replace existing spill infrastructure. Current operating procedures include ice load reduction activites at the spilling structures to ensure structural stability. A dam safety concern has been identified with respect to the minimal remote spilling capability at Slave Falls.

In-Service Date:
September 2021.

Revision:
In-service date advanced three years and four months from January 2025.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 126.1	$ -	$ 0.1	$ 0.1	$ 0.2	$ 0.5	$ 125.3
Increase (Decrease)	-	-	0.2	0.8	5.1	26.1	(32.1)
Revised Forecast	$ 126.1	$ -	$ 0.2	$ 0.9	$ 5.3	$ 26.6	$ 93.2

Water Licenses & Renewals

Description:
Conduct hydraulic studies, geotechnical assessments, property status and severance line determinations, mapping, license documentation, environmental reviews, and community informational sessions necessary to secure license finalization and/or renewals for the Corporation's hydraulic plants.

Justification:
All hydraulic generating facilities must be authorized under water power licenses and these licenses need to be clearly in force to significantly reduce risk exposure, maintain operating flexibility, maximize export revenues, and contribute to financial strength.

In-Service Date:
December 2017.

Revision:
Project scope has been expanded to include the International Institute of Sustainable Development (IISD) funding which continues with a new four year agreement, Lower Nelson River Sturgeon Stewardship Agreement (LNRSSA) liability core funding, Lower Nelson River Sturgeon Stewardship Agreement First Nations Committee Costs, the construction of spawning shoals for the Lake Sturgeon Stewardship and Enhancement Program (LSSEP) and the Lake Winnipeg Regulation Final Water Power Act License application with the CEC now requires a comprehensive plain language document be created for the process that covers a multitude of topics.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 53.5	$ 8.2	$ 5.6	$ 5.9	$ 6.2	$ 1.6	$ -
Increase (Decrease)	3.3	(0.6)	1.4	1.1	0.2	0.8	-
Revised Forecast	$ 56.8	$ 7.6	$ 7.0	$ 7.0	$ 6.5	$ 2.4	$ -

Pointe du Bois GS Rehabilitation

Description:
Implement safety upgrades for the Pointe du Bois generating station including fire protection, mechanical hazards, electrical hazards, operational hazards, trips and fall hazards, and various other safety upgrades. Additionally, implement turbine and generator, equipment and civil rehabilitation and upgrades.

Justification:
To provide a high level of health and safety upgrades as well as improved reliability and control, along with a reduction in potential environmental impacts from catastrophic events such as fire or flooding. The plan provides the most economical solution to operate the generating station for an additional twenty years.

In-Service Date:
July 2026.

Revision:
Cost flow revision and in-service date deferred two years and three months from April 2024.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 182.9	$ 7.1	$ 9.0	$ 18.8	$ 23.0	$ 21.3	$ 96.2
Increase (Decrease)	-	3.2	1.3	(3.5)	(1.3)	(1.8)	5.7
Revised Forecast	$ 182.9	$ 10.2	$ 10.3	$ 15.3	$ 21.7	$ 19.5	$ 101.9

Great Falls Unit 4 Overhaul

Description:
Major overhaul to generating Unit 4 including generator rewind, turbine re-runnering, new water passage embedded components, one 3-phase unit transformer, and modernization of components.

Justification:
The re-runnering and major overhaul will provide an opportunity to upgrade/modernize the unit while taking advantage of an already planned outage for the intake gates. The re-runnering will add both capacity and efficiency. The existing transformer is in poor condition and water passage components are starting to fail. The overhaul will increase reliability and extend the asset life by 40 to 50 years.

In-Service Date:
August 2015.

Revision:
In-service date deferred one year and eight months from December 2013. Increase in scope includes: refurbish generating station's service bay floor, upgrade line protection, upgrade powerhouse crane and repair damaged draft tube elbow.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 43.2	$ 19.9	$ 0.2	$ -	$ -	$ -	$ -
Increase (Decrease)	10.5	(15.3)	16.3	11.9	-	-	-
Revised Forecast	$ 53.6	$ 4.6	$ 16.5	$ 11.9	$ -	$ -	$ -

Brandon Units 6 & 7 "C" Overhaul Program

Description:
Perform C inspections/overhauls of the Brandon gas turbines Unit 6 & 7 when each of them acquires 24,000 Equivalent Operating Hours (EOH).

Justification:
The reliability of the hot gas path components cannot be predicted after 24,000 EOH. Failure of hot gas path parts could lead to significant collateral damage and an extended forced outage of the units.

In-Service Date:
March 2024.

Revision:
Cost flow revision and in-service date deferred three years and three months from December 2020.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 50.4	$ -	$ -	$ -	$ 5.9	$ 0.4	$ 44.1
Increase (Decrease)	-	-	-	-	(5.9)	(0.4)	6.3
Revised Forecast	$ 50.4	$ -	$ -	$ -	$ -	$ -	$ 50.4

TRANSMISSION:

Rockwood East 230/115kV Station

Description:
Design and construct a new 230/115kV Rockwood East Station adjacent to 230kV circuits A3R (Ashern-Rosser) and S65R (Silver-Rosser) including associated equipment, protection, control and communication systems. Sectionalize and extend 230kV and 115kV transmission lines as required and provide communication and protection upgrades.

Justification:
Construction of the Rockwood East Station with three 115kV line terminations would alleviate the overload scenarios for Rosser 230/115kV Banks 2 and 4 and for 115kV circuits CR4 or CR2 between Rosser and Parkdale Stations. It would also increase the 115kV capacity in the Rosser/Parkdale/Selkirk area. The existing Parkdale 115/66kV Station switchyard has very limited opportunity for adding new capacity due to the station's poor condition and limited space.

In-Service Date:
November 2015.

Revision:
Cost flow revision and in-service date deferred two months from September 2015.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 53.3	$ 15.1	$ 27.1	$ 7.9	$ -	$ -	$ -
Increase (Decrease)	-	(2.0)	1.9	0.7	-	-	-
Revised Forecast	$ 53.3	$ 13.1	$ 29.1	$ 8.6	$ -	$ -	$ -

Lake Winnipeg East System Improvements

Description:
Build a new 115/66kV Manigotagan Corner Station complete with two 6OMVA transformers, a new 65km, 115kV transmission line from Pine Falls Station to Manigotagan Corner Station, the associated terminations and communications, and the salvage of approximately 75kms of 66kV Line L77.

Justification:
Pine Falls Station currently operates over firm transformation during winter peak. The absence of firm transformation would cause customer outages in the Lake Winnipeg East area during a Pine Falls transformer outage. The outage would last greater than a week until a spare transformer could be brought in from Winnipeg and connected. A transformer outage would affect more than 1,300 permanent customers and more than 13,000 seasonal (summer) customers. Deferral will place customers at risk of no supply. The new 115/66kV Manigotagan Corner Station and Pine Falls – Manigotagan Corner 115kV Transmission Line will provide firm capacity for area load for the next 20 years, as well as enable the Bloodvein SVC to control effectively the voltage at Bloodvein, Little Grand Rapids, Beren's River and Poplar River for the next 20 years. It also reduces the loading on Pine Falls 115/66kV accommodating load growth in the Victoria Beach, Grand Beach and Bissett areas.

In-Service Date:
November 2015.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 64.6	$ 22.4	$ 23.8	$ 13.0	$ 2.3	$ -	$ -
Increase (Decrease)	-	(7.2)	6.2	4.2	(2.3)	-	-
Revised Forecast	$ 64.6	$ 15.2	$ 30.0	$ 17.2	$ -	$ -	$ -

Letellier - St. Vital 230kV Transmission

Description:
Design and construct a new 230kV line from Letellier Station to St. Vital Station including associated terminations and communications. Includes environmental licensing and monitoring, and property rights acquisition.

Justification:
The supply to Letellier Station must be improved in order to overcome the contingency loading and low voltage problems in the south central area of Manitoba caused by load growth, as well as to maintain export levels on the 230kV Tie Line L20D (Letellier to Drayton) at these increased loads.

In-Service Date:
August 2016.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 59.0	$ 2.2	$ 7.6	$ 30.8	$ 17.9	$ -	$ -
Increase (Decrease)	-	(1.0)	(4.6)	4.1	0.2	1.6	-
Revised Forecast	$ 59.0	$ 1.2	$ 3.0	$ 34.9	$ 18.1	$ 1.6	$ -

Transmission Line Upgrades for NERC Alert

Description:
Establish a new major capital project involving a nine year program to upgrade over 1000 transmission line spans to meet CSA Standards for line clearance. A priority listing of the transmission lines and spans requiring mitigation will be developed based on assessment work considering operational and safety risks specific to each line/span.

Justification:
This program addresses discrepancies between the design ratings and actual field ratings of transmission lines thereby ensuring continued reliability and operation of the electrical system as well as mitigating risks to public safety due to insufficient line clearance.

In-Service Date:
March 2023.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	151.3	-	1.1	8.9	9.0	9.1	123.2
Revised Forecast	$ 151.3	$ -	$ 1.1	$ 8.9	$ 9.0	$ 9.1	$ 123.2

HVDC Dorsey Synchronous Condenser Refurbishment

Description:
Major inspection, re-wedging and overhaul of synchronous condensers SC7Y, SC8Y, SC9Y, SC21Y, SC22Y and SC23Y. Replace coolers to restore original thermal performance on SC21Y, and SC23Y. Repair corrosion problems and replace GEM80 PLC on SC7Y, SC8Y and SC9Y. Modify the 600V transfer scheme for SC8Y, SC7Y & SC9Y.

Justification:
Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the United States. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with the inability to export power will well exceed the cost of major inspection and overhaul.

In-Service Date:
October 2019.

Revision:
Cost flow revision and in-service date deferred one year and seven months from March 2018.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 73.3	$ 5.8	$ 8.7	$ 11.0	$ 7.6	$ 5.4	$ 4.8
Increase (Decrease)	-	0.9	(0.7)	(2.1)	0.9	0.5	(0.7)
Revised Forecast	$ 73.3	$ 6.7	$ 7.9	$ 8.9	$ 8.5	$ 5.9	$ 4.2

Dorsey 230kV Phase II Zone Building

Description:
Construction and equipping of two new zone buildings and refurbishing of the existing relay building and equipment. This project also includes installing and replacing various pieces of equipment and modifications to the switchyard.

Justification:
Construction of two new hardened relay buildings plus the hardening and conversion of the existing relay building is the most cost effective and practical option. This approach segregates the 230kV switchyard into three sections, providing for the majority of the 230kV switchyard to remain operational following the loss of a zone building. This meets Manitoba Hydro’s system restoration criteria.

In-Service Date:
March 2021.

Revision:
Cost flow revision only.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 63.4	$ -	$ -	$ -	$ 0.4	$ 16.5	$ 46.5
Increase (Decrease)	-	-	-	-	-	(0.1)	0.1
Revised Forecast	$ 63.4	$ -	$ -	$ -	$ 0.4	$ 16.5	$ 46.6

Bipole 2 Thyristor Valve Replacement

Description:
Removal of the existing eight (8) thyristor valve groups and their controls, and replace them with eight new de-ionized water cooled HVDC thyristor valve groups and controls.

Justification:
The Bipole 2 thyristor valves and controls are nearing the end of their useful life and require replacement. Replacing the existing thyristor valve groups and controls with new ones will result in reducing the probability of forced outages. This will result in a significant decrease in failures, reduce maintenance requirements, and generally improved reliability for Bipole 2.

In-Service Date:
October 2023

Revision:
None.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 233.7	$ -	$ -	$ -	$ -	$ 2.1	$ 231.6
Increase (Decrease)	-	-	-	-	-	-	-
Revised Forecast	$ 233.7	$ -	$ -	$ -	$ -	$ 2.1	$ 231.6

CUSTOMER SERVICE & DISTRIBUTION:

New Madison Station - 115/24kV Station

Description:
Build a new 115/24kV St. James Station, new and upgraded feeders, and conversion of St. James, Ness, Berry and King Edward station feeders from 4kV to 24kV.

Justification:
This project is required to ensure firm supply and a reliable system in the St. James area.

In-Service Date:
March 2016.

Revision:
In-service date advanced seven months from October 2016. Project name changed from St. James New Station & 24kV Conversion to New Madison Station – 115/24kV Station. Increase project scope from two to three 115/24kV, 60MVA transformer banks at the new station site. Remove 24kV/4kV feeder conversions from the project scope and re-supply St. James 4kV distribution through 24kV/4kV step-down transformation. Remove new 24kV feeder installations, J54 and J56.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 65.9	$ 18.4	$ 20.8	$ 22.3	$ 0.4	$ -	$ -
Increase (Decrease)	3.7	(16.4)	(0.8)	3.3	15.7	1.3	-
Revised Forecast	$ 69.6	$ 2.1	$ 20.0	$ 25.6	$ 16.1	$ 1.3	$ -

St. Vital Station - 115/24kV Station

Description:
Install a 3-bank 115/24kV station complete with nine feeder positions and protection to replace the existing 24kV distribution at St. Vital Station.

Justification:
The project addresses the equipment rating concerns currently mitigated by station operating restrictions and customer-driven demand for electricity in the area, as well as restoring reliable station contingency plans.

In-Service Date:
December 2018.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	51.3	0.1	0.3	3.0	20.0	20.0	7.9
Revised Forecast	$ 51.3	$ 0.1	$ 0.3	$ 3.0	$ 20.0	$ 20.0	$ 7.9

Dawson Road Station - 115/24kV Station

Description:
Install a 2-bank 115kV/24kV station complete with six feeder positions and two capacitor banks to replace existing 24kV distribution equipment at Dawson Road Station.

Justification:
Justification is based on fulfilling customer-driven demand for electricity in the area as well as providing a reliable supply to customers in contingency situations.

In-Service Date:
December 2019.

Revision:
New item.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	51.8	-	2.5	0.5	3.0	16.5	29.3
Revised Forecast	$ 51.8	$ -	$ 2.5	$ 0.5	$ 3.0	$ 16.5	$ 29.3

Burrows New 66/12kV Station

Description:
Build a new two bank 66kV/12kV indoor station, complete with 12 feeder positions and protection to replace the Alfred and Charles stations.

Justification:
Most of the equipment in this part of Winnipeg has been in service for 77 years. Alfred Station (which supplies Charles Station) lacks access to a satisfactory alternate supply in the event of a 12kV interruption out of Rover Station. Remedial action was recommended for both stations in the Due Diligence Report. It indicated the 4kV switchgear lineups at Alfred and Charles Stations lack arc-resistance and at Alfred Station are sometimes underrated for the available fault current during normal operating conditions. It also had concerns that neither station has an appropriate battery room, all station transformers have patched leaks, they contain asbestos materials, and that spare parts are in short supply.

In-Service Date:
March 2015.

Revision:
In-service date deferred two years from March 2013. Increase estimate to complete the feeder conversions, to install the new 66kV underground supply and other cost revisions.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	$ 42.6	$ 4.2	$ 2.2	$ -	$ -	$ -	$ -
Increase (Decrease)	12.1	4.5	3.0	-	-	-	-
Revised Forecast	$ 54.7	$ 8.7	$ 5.1	$ -	$ -	$ -	$ -

BASE CAPITAL:

ELECTRIC OPERATIONS:

Generation Operations

Description:
These projects are required to provide safe, reliable, efficient supply of power, and to replace plant facilities which are at the end of their useful life. This is comprised of:

GENERATION – Projects relating to upgrading or replacing infrastructure, controls, transformers, breakers, and other equipment at existing generating stations.

GENERATION TOWN SITE SERVICES - Projects required to maintain facilities and provide services to town sites such as Gillam, Grand Rapids and Seven Sisters.

OTHER CAPITAL - Projects relating to upgrading replacing or enhancing domestic water and waste water systems, security systems, office, plant and field equipment replacements; communications; tools and test equipment as well as geotechnical investigation of various contaminated corporate facilities to remediate contaminated areas to environmentally acceptable limits.

Justification:
The generation availability of the older assets has been declining over the last ten years. As Generation Operation's assets age, there is an increase in risk to their availability, which could result in months or years of unit outages and significantly impact the ability to produce power to the transmission system. Enhancements or rehabilitation to the power supply facilities will ensure a safe, reliable and efficient source of energy.

Revision:
Plan reduced to account for the corporate reorganization and transfer of the HVDC Division from Generation Operations to the Transmission Business Unit as well as adjustments to base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 102.5	$ 145.7	$ 114.6	$ 92.7	$ 52.5	$ 1 494.9
Increase (Decrease)		(4.3)	(51.4)	(26.9)	9.1	11.4	(334.2)
Revised Forecast	NA	$ 98.2	$ 94.2	$ 87.7	$ 101.8	$ 63.9	$ 1 160.7

Transmission

Description:
The majority of projects consist of additions, improvements and replacement of transmission lines; replacement, development and upgrades to HVDC facilities; replacement, development and upgrades to communication systems; additions and replacement of field maintenance equipment; and station upgrades. This is comprised of:

SYSTEM RELIABILITY – Projects that address the reliability or capacity of the transmission, or communication systems, including system emergencies and regulatory compliance.

HVDC FACILITIES - Projects relating to upgrading or replacing transformers, breakers, smoothing reactors, protection, controls and other equipment at HVDC facilities.

CUSTOMER SERVICE - Projects that address new or existing service extensions to larger customers.

ENVIRONMENTAL - Projects that enhance or restore the environment, mitigate damage or potential damage to the environment or remove/salvage plant.

SAFETY – Projects that address risk to public or employee safety or emergency preparedness.

OTHER- Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
This program ensures the reliability of transmission with respect to load, outages, and import/export requirements; as well as addresses safety issues and provides the necessary support for the operation of the HVDC, transmission and communication systems.

Revision:
Plan increased to account for the corporate reorganization and transfer of the HVDC Division from Generation Operations to the Transmission Business Unit in the early forecast period offset by adjustments to the base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 66.8	$ 90.5	$ 72.3	$ 47.3	$ 39.1	$ 1 657.8
Increase (Decrease)		37.3	24.4	53.8	64.7	31.2	(380.7)
Revised Forecast	NA	$ 104.1	$ 114.9	$ 126.1	$ 112.0	$ 70.3	$ 1 277.0

Customer Service & Distribution

Description:
These projects are required to extend sub-transmission, distribution, and transformation facilities to supply service to residential, farm, commercial and industrial customers, and to replace plant facilities whose useful life has been exceeded. Specific types of expenditures include station and line additions, modifications and rebuilds, bank additions, breaker replacements, defective cable replacement, highway changes, field maintenance equipment, woodpole replacements and ice melting requirements. These costs are spread over many facility locations throughout the Province and are comprised of:

SYSTEM IMPROVEMENTS - Projects relating to additions and modifications to the existing electric distribution network to maintain system reliability and standards of safety, as a result of customer load growth, aging infrastructure and operational standards of performance. Assets and facilities include distribution stations, poles, conductors, transformers, streetlights, cables, duct lines and manholes.

CUSTOMER SERVICE - Projects relating to new or existing service extensions to commercial and residential customers.

NEW STATIONS - Projects relating to station development requirements in both Winnipeg and rural Manitoba to address capacity limitations.

OTHER CAPITAL - Projects relating to VHF radio replacements and field maintenance equipment.

Justification:
The residential, farm, commercial and industrial loads are expected to grow at an average rate in excess of 1.5% per annum and will require a program of additions to the system to accommodate these anticipated loads. As the distribution assets are approaching the end of their designated lifespan a four year program has been established to replace critical infrastructure.

Revision:
Increased target values to accommodate expenditures required to rehabilitate and replace the aging assets based upon condition assessment data.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 176.3	$ 162.8	$ 152.8	$ 142.4	$ 144.7	$ 3 438.3
Increase (Decrease)		(0.9)	44.8	58.9	86.8	(0.8)	100.0
Revised Forecast	NA	$ 175.4	$ 207.6	$ 211.8	$ 229.2	$ 143.8	$ 3 538.3

Customer Care & Energy Conservation

Description:
This program covers the additions and replacements of meters, transformers and related equipment and is comprised of:

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

OTHER– Projects to acquire tools and equipment that support operation and maintenance of the electric system.

Justification:
As required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Decreases due to the removal of the Advanced Metering Infrastructure program until a review has been completed.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 3.1	$ 7.9	$ 9.3	$ 9.4	$ 9.7	$ 80.1
Increase (Decrease)		-	(4.7)	(6.1)	(6.2)	(6.4)	(21.4)
Revised Forecast	NA	$ 3.1	$ 3.1	$ 3.2	$ 3.3	$ 3.3	$ 58.6

Human Resources & Corporate Services

Description:
The program consists of information technology hardware and software upgrades and application development, corporate building refurbishments and new building programs, fleet vehicle refurbishment and replacement as well as projects associated with property easements, and acquisition of equipment for the training centre, print shop, fleet, materials management, and facilities.

CORPORATE BUILDINGS - Projects associated with the cyclical acquisition, and/or replacement of corporate administrative facilities throughout the Province.

FLEET ACQUISITIONS - Projects associated with the cyclical procurement, refurbishment and/or replacement of corporate fleet vehicles and equipment.

INFORMATION TECHNOLOGY HARDWARE / SOFTWARE - Projects associated with the purchase and installation of hardware and software upgrades, personal computers, networks and cabling.

INFORMATION APPLICATION DEVELOPMENT - Projects associated with developing computer applications. Significant projects include: Enterprise Asset Management, Capital Portfolio Management, Corporate Laboratory Information Management System upgrade, Generation Performance & Reporting System, Predictive Analytics Project and Travel and Expense Management System.

OTHER – Projects associated primarily with property easements and equipment for the training centre, print shop, fleet, materials management and facilities.

Justification:
To provide safe, efficient and productive; corporate buildings, fleet vehicles and equipment. Also to enhance computer systems throughout the corporation to achieve ongoing improvement in productivity and reliability.

Revision:
Increases due mainly to the new fleet building and two new district offices in the earlier forecast years. The decrease in the latter portion is due to the adjustment to base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 48.1	$ 53.3	$ 50.6	$ 50.5	$ 51.4	$ 885.5
Increase (Decrease)		13.3	22.4	4.2	4.3	(17.0)	(260.7)
Revised Forecast	NA	$ 61.4	$ 75.7	$ 54.8	$ 54.8	$ 34.4	$ 624.8

Finance & Regulatory

Description:
This program is primarily for meter purchases (for load research monitoring), and handheld devices associated with the load research function. Other items include the purchase of additional servers and other information technology related equipment and specialized software.

Justification:
The load research program supports the development of customer rates and also supports Power Smart initiatives in terms of planning and support.

Revision:
No changes.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.8
Increase (Decrease)		-	-	-	-	-	(0.1)
Revised Forecast	NA	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 3.7

GAS OPERATIONS:

Customer Service & Distribution

Description:
This program consists of projects required to extend, rebuild or upgrade: transmission pipelines, distribution pipelines, regulating stations, and customer service lines. This is comprised of:

SYSTEM IMPROVEMENTS – Projects relating to system modifications and betterment. Significant work includes capacity upgrades, system integrity upgrades, regulator station upgrades and cathodic protection upgrades.

NEW BUSINESS - Projects for installing new services and distribution mains for both commercial and residential customers.

Justification:
Required to provide ongoing safe and reliable supply of natural gas to customers.

Revision:
Increased costs for infrastructure additions and target increases for unplanned system improvements. The decrease in the latter portion is due to the adjustment to base capital targets beyond 2017/18.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 22.5	$ 26.7	$ 27.3	$ 27.8	$ 28.4	$ 500.3
Increase (Decrease)		13.2	8.2	21.8	7.1	(6.1)	(18.3)
Revised Forecast	NA	$ 35.7	$ 34.9	$ 49.0	$ 34.9	$ 22.3	$ 482.0

Customer Care & Energy Conservation

Description:
This program consists primarily of costs to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba, as well as meters, transformers and related equipment. This is comprised of:

GAS DEMAND SIDE MANAGEMENT – Projects to design, implement and deliver incentive based PowerSmart conservation programs to reduce gas consumption and greenhouse gas emissions in Manitoba.

CUSTOMER SERVICE – Projects that address service to a customer or customer-driven requests, including costs associated with new and replacement metering equipment, metering transformers and associated equipment.

Justification:
The natural gas Demand Side Management plan provides customers with exceptional value through the implementation of cost-effective energy conservation programs that are designed to minimize the total cost of energy services to customers, position the Corporation as a national leader in implementing cost-effective energy conservation and alternative energy programs, protect the environment and promote sustainable energy supply and service. Also required for the connection of new customers to the system, as well as replacement of existing time expired or faulty meters.

Revision:
Increases due to the assumption that upon adoption of IFRS in 2015/16, the Gas Demand Side Management programs will continue to be capitalized, under an interim standard that continues to permit rate-regulated accounting. These increases are partially offset by the removal of the Advanced Metering Infrastructure program until a review has been completed.

	Total	2014	2015	2016	2017	2018	2019-33
Previously Approved	NA	$ 13.7	$ 6.0	$ 10.6	$ 13.5	$ 5.3	$ 94.1
Increase (Decrease)		-	7.4	1.7	(1.4)	4.8	42.5
Revised Forecast	NA	$ 13.7	$ 13.4	$ 12.3	$ 12.1	$ 10.1	$ 136.6

PUB/MH I-14

Reference: WPLP

Please provide the most current IFF for WPLP.

ANSWER:

Please see the following statements.

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES										
Revenue	43	48	67	74	81	90	93	95	104	108
	43	48	67	74	81	90	93	95	104	108
EXPENSES										
Operating and Administrative	13	13	12	12	12	12	13	13	13	13
Finance Expense	70	75	75	76	76	74	73	72	71	69
Depreciation and Amortization	27	27	28	28	28	28	28	28	28	28
Water Rentals and Assessments	5	6	5	5	5	5	5	5	5	5
	115	121	120	122	121	120	119	118	117	116
Net Income	(71)	(73)	(53)	(48)	(40)	(30)	(25)	(22)	(13)	(8)
Financial Ratios										
Debt	83%	85%	85%	85%	85%	85%	85%	85%	85%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REVENUES										
Revenue	115	119	115	118	120	123	128	133	137	142
	115	119	115	118	120	123	128	133	137	142
EXPENSES										
Operating and Administrative	14	14	14	14	15	15	13	12	13	13
Finance Expense	63	61	61	57	56	54	53	51	50	49
Depreciation and Amortization	28	28	28	28	28	28	28	28	28	28
Water Rentals and Assessments	5	5	5	5	5	5	5	5	5	5
	110	108	108	104	103	102	99	97	96	95
Net Income	5	10	7	13	17	21	29	35	41	47
Financial Ratios										
Debt	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	1 367	1 376	1 406	1 406	1 406	1 406	1 406	1 406	1 406	1 410
Accumulated Depreciation	(32)	(52)	(73)	(96)	(118)	(140)	(162)	(184)	(206)	(228)
Net Plant in Service	1 335	1 325	1 333	1 311	1 289	1 267	1 245	1 223	1 201	1 182
Construction in Progress	4	18	-	-	-	-	-	-	-	-
Current and Other Assets	304	309	315	321	329	336	344	352	361	370
	1 643	1 651	1 648	1 632	1 617	1 603	1 589	1 575	1 561	1 552
LIABILITIES AND EQUITY										
Long-Term Debt	1 336	1 334	1 333	1 332	1 330	1 329	1 327	1 325	1 323	1 321
Current and Other Liabilities	81	110	110	101	93	86	78	70	64	(91)
Partners Capital	226	207	205	199	194	189	184	180	174	322
	1 643	1 651	1 648	1 632	1 617	1 603	1 589	1 575	1 561	1 552
Debt Ratio	83%	85%	85%	85%	85%	85%	85%	85%	85%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	1 410	1 410	1 410	1 410	1 410	1 410	1 410	1 410	1 410	1 414
Accumulated Depreciation	(250)	(272)	(294)	(316)	(339)	(361)	(383)	(405)	(427)	(449)
Net Plant in Service	1 160	1 138	1 116	1 093	1 071	1 049	1 027	1 005	983	965
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	380	390	401	412	424	437	450	465	480	496
	1 540	1 528	1 516	1 505	1 495	1 486	1 478	1 470	1 463	1 461
LIABILITIES AND EQUITY										
Long-Term Debt	1 319	1 317	1 315	1 312	1 309	1 307	1 304	1 301	1 297	1 294
Current and Other Liabilities	(39)	(59)	(57)	(58)	(58)	(58)	(55)	(51)	(47)	(40)
Partners Capital	260	270	259	252	244	237	228	221	213	207
	1 540	1 528	1 516	1 505	1 495	1 486	1 478	1 470	1 463	1 461
Debt Ratio	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	43	48	67	74	81	90	93	95	104	108
Cash Paid to Suppliers and Employe	(18)	(19)	(17)	(17)	(17)	(17)	(18)	(18)	(18)	(18)
Interest Paid	(70)	(75)	(77)	(78)	(77)	(77)	(76)	(75)	(75)	(74)
Interest Received	-	0	1	1	2	2	3	4	4	5
	(44)	(46)	(27)	(20)	(12)	(2)	3	6	15	20
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	232	-	-	-	-	-	-	-	-	-
Other	9	1	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
	242	1	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net	(45)	(23)	(11)	-	-	-	-	-	-	(3)
Sinking Fund Payment	(10)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)
Other	-	-	51	51	43	35	24	21	18	8
	(55)	(34)	28	38	29	22	11	6	3	(11)
Net Increase (Decrease) in Cash	143	(80)	(1)	17	16	18	12	10	16	7
Cash at Beginning of Year	(186)	(43)	(122)	(123)	(106)	(90)	(72)	(60)	(50)	(34)
Cash at End of Year	(43)	(122)	(123)	(106)	(90)	(72)	(60)	(50)	(34)	(26)

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
OPERATING ACTIVITIES										
Cash Receipts from Customers	115	119	115	118	120	123	128	133	137	142
Cash Paid to Suppliers and Employe	(19)	(19)	(19)	(19)	(20)	(20)	(18)	(17)	(18)	(18)
Interest Paid	(69)	(67)	(67)	(67)	(67)	(66)	(66)	(66)	(66)	(65)
Interest Received	5	6	7	10	11	12	13	14	15	17
	33	39	36	42	45	49	57	64	69	75
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net	-	-	-	-	-	-	-	-	-	(4)
Sinking Fund Payment	(16)	(16)	(17)	(18)	(18)	(19)	(20)	(21)	(21)	(22)
Other	155	(67)	(0)	(18)	(20)	(24)	(28)	(38)	(43)	(49)
	140	(83)	(17)	(36)	(39)	(43)	(48)	(58)	(65)	(75)
Net Increase (Decrease) in Cash	170	(47)	16	3	4	3	6	3	2	(3)
Cash at Beginning of Year	(26)	144	97	113	117	120	124	130	132	134
Cash at End of Year	144	97	113	117	120	124	130	132	134	131

PUB/MH I-15

Reference: Interim Application Page 16 line 16; Internally Generated Funds

a) Please provide an update to PUB/MH II-56 (b) from the 2012 GRA based on IFF13 from 2004/05 through 2032/33.

ANSWER:

Please see the table below.

	(000's)	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
	General Consumer Revenue	$ 938 954	$ 983 653	$ 1 023 613	$ 1 074 580	$ 1 126 812	$ 1 144 891	$ 1 200 381	$ 1 191 117	$ 1 341 009	$ 1 377 596	$ 1 442 068	$ 1 515 573	$ 1 591 916	$ 1 683 041	$ 1 785 031
	Extraprovincial Revenue	553 727	826 766	592 245	624 971	622 646	426 641	398 306	363 044	352 633	408 426	382 904	76 781	89 812	127 248	123 508
1)	Total General Consumer & Extraprovincial Revenue*	$ 1 492 681	$ 1 810 419	$ 1 615 858	$ 1 699 551	$ 1 749 459	$ 1 571 532	$ 1 598 687	$ 1 554 161	$ 1 693 642	$ 1 786 022	$ 1 824 972	$ 1 592 354	$ 1 681 728	$ 1 810 289	$ 1 908 539
2)	Fund Operations	$ 1 086 681	$ 1 098 419	$ 1 194 858	$ 1 100 551	$ 1 096 459	$ 1 043 532	$ 1 048 687	$ 1 036 161	$ 1 139 642	$ 1 236 574	$ 1 332 026	$ 1 064 356	$ 1 156 288	$ 1 332 265	$ 1 366 475
3)	Fund Base Capital	337 000	283 000	376 000	363 000	359 000	414 000	450 000	472 000	437 000	526 160	636 869	631 441	631 735	467 610	474 448
4)	Fund Major Capital (from internally generated funds from operations)	69 000	429 000	45 000	236 000	294 000	114 000	100 000	46 000	117 000	23 288	-	-	-	10 414	67 616
5)	Fund Base Capital (from new debt)	-	-	-	-	-	-	-	-	-	-	143 923	103 443	106 295	-	-

	(000's)	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
	General Consumer Revenue	$ 1 879 312	$ 1 978 277	$ 2 082 659	$ 2 193 110	$ 2 309 340	$ 2 432 350	$ 2 561 348	$ 2 695 698	$ 2 836 861	$ 2 988 799	$ 3 148 028	$ 3 314 390	$ 3 488 321	$ 3 670 822
	Extraprovincial Revenue	154 602	386 349	470 642	479 951	470 614	440 556	370 956	557 974	819 486	901 952	889 579	890 182	894 306	886 229
1)	Total General Consumer & Extraprovincial Revenue*	$ 2 033 914	$ 2 364 626	$ 2 553 301	$ 2 673 061	$ 2 779 954	$ 2 872 906	$ 2 932 304	$ 3 253 672	$ 3 656 347	$ 3 890 751	$ 4 037 607	$ 4 204 572	$ 4 382 627	$ 4 557 051
2)	Fund Operations	$ 1 478 627	$ 1 724 276	$ 1 817 819	$ 1 845 025	$ 1 882 698	$ 1 928 309	$ 1 827 262	$ 2 067 469	$ 2 427 472	$ 2 498 009	$ 2 507 316	$ 2 446 261	$ 2 406 168	$ 2 418 989
3)	Fund Base Capital	477 216	480 535	484 247	486 993	493 364	493 178	498 669	503 425	508 477	512 028	519 954	521 353	525 860	530 620
4)	Fund Major Capital (from internally generated funds from operations)	78 071	159 815	251 235	341 043	403 892	451 419	606 373	682 778	720 398	880 714	1 010 337	1 236 958	1 450 599	1 607 442
5)	Fund Base Capital (from new debt)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

* Please note that not all revenue collected in a fiscal year is received as cash, resulting in a receivable. This response has been provided for illustrative purposes only.

<u>PUB/MH I-15</u>

Reference: Interim Application Page 16 line 16; Internally Generated Funds

b) Please explain the changes in internally generated funds there were forecast in MH12-1 with those forecast in MH13-1 and explain the reasons for the changes.

<u>ANSWER</u>:

Please see the schedule of Operating Activities (Internally Generated Funds) changes between the two forecasts.

Cash receipts are generally down except for the first two fiscal years because of decreased revenues. Cash payments to suppliers and employees expensed through O&A, Fuel and Power purchases and government payments for water rentals and taxes are lower than forecast in MH12. Interest payments are greater in MH13 due to capital investments. Interest income is relatively unchanged.

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH13 LESS MH12
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES										
Cash Receipts from Customers	50	23	(37)	(35)	(21)	(27)	(12)	11	(21)	(44)
Cash Paid to Suppliers and Employees	14	92	39	43	49	59	66	54	65	50
Interest Paid	(14)	3	22	26	12	(3)	(41)	(108)	(107)	(107)
Interest Received	9	(11)	(10)	(8)	(6)	(4)	(3)	(4)	(3)	(2)
	58	108	15	26	34	25	9	(46)	(67)	(102)

For the year ended March 31	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
OPERATING ACTIVITIES										
Cash Receipts from Customers	(40)	(51)	(215)	(315)	(143)	(61)	(81)	(110)	(115)	14
Cash Paid to Suppliers and Employees	56	65	53	49	64	57	62	81	81	89
Interest Paid	(117)	(125)	7	120	(2)	(220)	(230)	(243)	(252)	(266)
Interest Received	(3)	(3)	(2)	(0)	2	5	7	9	9	12
	(104)	(114)	(157)	(146)	(79)	(219)	(242)	(263)	(278)	(151)

PUB/MH I-16

Reference: Staffing

a) Please file an update to PUB/MH I-37 (a) from the 2012 GRA.

ANSWER:

The following schedule identifies actual EFTs (straight time and overtime) for the fiscal years 2004/05 to 2012/13, as well as forecast EFTs for the 2013/14 fiscal year.

The 2013/14 forecast reflects an increase of 280 EFTs related to increased capital staffing requirements associated with Bipole III, Keeyask, Conawapa and other capital initiatives. In addition, higher trainee levels are required to meet current and expected attrition levels for various programs including the Power Electrician program.

The forecast for 2013/14 anticipated the filling of vacant positions; however, similar to the actual results for 2012/13 as shown in Manitoba Hydro's response to PUB 1-16(b), preliminary results indicate that vacancies remain unfilled due to cost containment measures.

The annual detailed operating budget process for fiscal 2014/15 is currently underway and will incorporate further cost containment measures as discussed in PUB/MH 1-30(d), as such divisional EFT information is not available at this time.

MANITOBA HYDRO

EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast
President & CEO										
Public Affairs	32	30	30	31	32	34	33	33	33	34
Administration	13	13	14	14	14	17	19	19	18	15
	45	43	44	45	46	51	52	52	50	49
General Counsel & Corporate Secretary										
Law Division	15	16	16	17	16	18	18	19	19	18
Internal Audit Division	10	11	12	13	12	12	13	13	11	14
Administration	9	9	10	11	10	11	12	13	14	18
	35	36	38	40	39	41	43	45	45	50
Human Resources & Corporate Services										
Information Technology Services	350	364	336	313	313	313	314	312	304	307
Human Resources	169	165	166	164	168	158	153	150	150	156
Workplace Safety & Health and Corp Serv	329	323	325	334	341	349	355	344	347	363
Corporate Environmental Management	-	-	-	1	2	3	4	5	5	4
Administration	8	9	11	11	11	11	11	11	10	5
	856	861	838	823	835	834	837	823	817	835
Corporate Relations										
Aboriginal Relations	44	54	59	61	67	68	65	66	67	73
Corporate Planning & Strategic Review	21	20	19	17	17	18	21	21	19	18
Administration	5	8	8	7	8	5	4	3	3	5
	70	81	86	86	92	91	89	90	89	96

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast
Finance & Regulatory										
Treasury	17	16	15	15	16	14	13	13	14	14
Corporate Risk Mgmt Department	1	2	3	4	5	5	6	6	6	7
Rates & Regulatory Affairs	22	19	19	19	19	20	22	21	20	22
Corporate Controller	108	103	97	101	100	104	101	93	96	94
Administration	15	15	16	14	15	16	14	12	13	21
	162	154	150	152	154	159	156	146	149	158
Generation Operations										
Power Planning	32	35	42	55	58	66	75	78	79	78
Generation North	234	213	211	215	219	224	235	249	255	272
Generation South	496	462	459	455	459	471	488	489	486	484
Power Sales & Operations	79	84	82	84	84	82	86	88	87	95
Engineering Services	163	162	176	175	183	214	233	239	233	252
Administration	23	23	24	23	24	23	23	24	23	20
	1,026	978	994	1,006	1,027	1,080	1,139	1,166	1,163	1,202
Major Capital Projects										
Power Projects Development	38	37	39	42	44	47	48	53	56	63
Portfolio Projects Management	-	0	3	4	5	4	6	9	12	16
Bipole III Project	-	-	-	-	-	-	6	9	17	40
New Generation Construction	13	14	25	55	83	108	119	128	140	161
Administration	-	-	-	-	-	-	-	-	-	2
	52	52	67	102	132	159	178	198	225	282

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast
Transmission										
Transmission System Operations	341	346	363	362	362	364	365	356	357	363
Transmission Planning & Design	202	195	193	178	191	206	214	233	237	256
Transmission Construction & Line Mtce	271	276	274	273	276	292	303	301	304	335
Apparatus Maintenance	357	362	365	397	420	431	434	428	419	436
HVDC	266	228	232	235	250	254	260	258	263	282
Administration	37	150	151	173	215	236	267	267	296	297
	1,475	1,557	1,578	1,618	1,714	1,782	1,844	1,842	1,876	1,970
Customer Service & Distribution										
Customer Service Operations - Wpg&North	535	537	515	520	530	528	532	508	509	516
Customer Service Operations - South	543	566	552	554	558	568	570	551	564	559
Distribution E&C Rural	231	234	235	250	258	259	269	288	283	282
Distribution E&C Winnipeg	271	287	282	283	291	288	298	296	307	321
Business Support & Capital Asset Mgmt	52	52	60	60	63	59	60	82	92	104
Administration	-	-	-	-	-	5	6	7	6	6
	1,633	1,676	1,644	1,666	1,700	1,706	1,734	1,733	1,760	1,788
Customer Care & Energy Conservation										
Industrial & Commercial Solutions	51	52	54	55	57	60	57	55	58	61
Consumer Marketing & Sales	204	221	228	218	216	207	210	199	194	208
Business Support Services	202	209	211	203	200	193	187	189	186	193
Gas Supply	20	20	19	19	20	20	21	20	20	19
Administration	39	39	39	39	44	46	47	49	45	47
	517	540	551	534	537	526	522	512	503	529
Total	5,870	5,978	5,988	6,071	6,276	6,429	6,594	6,608	6,678	6,958

<u>PUB/MH I-16</u>

Reference: Staffing

b) Please provide a comparison of actual EFTs for 2012/13 and 2013/14 with the level forecast for those years at the last GRA and provide a narrative explanation of the differences.

<u>ANSWER</u>:

Please see the following table comparing 2012/13 actual EFTs against 2012/13 forecast EFTs by business unit along with explanations of 5 or greater change in EFTs. EFTs include straight time and overtime. Fiscal 2014 actual results are not available at this time.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2012/13 Forecast	2012/13 Actual	Over/(Under)	Note
President & CEO	52	50	(2)	
General Counsel & Corporate Secretary	46	45	(1)	
Human Resources & Corporate Services	841	817	(24)	1
Corporate Relations	94	89	(5)	2
Finance & Regulatory	147	149	2	
Generation Operations	1 200	1 163	(37)	3
Major Capital Projects	252	225	(27)	4
Transmission	1 905	1 876	(29)	5
Customer Service & Distribution	1 776	1 760	(16)	6
Customer Care & Energy Conservation	523	503	(20)	7
Total	6 837	6 678	(159)	

*Explanations provided for Business Units with variance of 5 EFTs or greater.

Explanations:

1. Primarily due to vacancies in areas such as Fleet Services & IT Services and Human Resources.
2. Primarily due to vacancies in the support staff area.
3. Mainly due to vacancies in various positions at the Grand Rapids and Selkirk generating stations, in the Enterprise Asset Management project as well in the Civil and Electrical Engineering functions. Also lower overtime requirements in projects such as Jenpeg Shaft Seal Replacement, Pointe Du Bois Unit Rehabilitation and Public Safety Around Dams.
4. New positions not yet filled for major projects such as Keeyask, Bipole III and Conawapa.
5. Mainly due to vacancies in the construction and line maintenance areas as well as the EIT program.
6. Primarily due to vacancies in various service and technical areas related to gas and electric operations.
7. Mainly related to vacancies in marketing programs as well as billing and metering services.

<u>PUB/MH I-16</u>

Reference: Staffing

c) Please provide a table/ matrix of EFT per GWh, per domestic revenue, and per domestic customers on an annual basis from 1999/00 to 2014/15.

	1999/00	***[…]***	***[…]***	***2014/15***
EFT's				
EFT per GWH of domestic Supply				
EFT per GWH of total supply				
EFT per number of domestic customers				
EFT's per $ of domestic revenue				

<u>ANSWER</u>:

Please see the following table for the requested information.

Data Table	Actual									Forecast	
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EFT (ST & OT)	5 870	5 978	5 988	6 071	6 276	6 426	6 592	6 607	6 678	6 958	6 958
GWh of domestic Supply	22 452	22 622	23 327	23 985	24 285	23 295	23 783	23 499	24 642	25 162	25 541
GWh of total Supply	31 548	37 620	32 132	35 354	34 528	33 961	34 102	33 235	33 230	35 257	34 453
Electric Customers	505 666	509 791	516 861	521 599	527 472	532 359	537 299	542 681	548 774	554 957	561 140
Domestic revenue (in millions)	939	984	1 024	1 075	1 127	1 145	1 200	1 191	1 341	1 378	1 442

Information Requested	Actual									Forecast	
	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EFT (ST & OT)	5 870	5 978	5 988	6 071	6 276	6 426	6 592	6 607	6 678	6 958	6 958
EFT (ST & OT) per 1000 GWh of domestic supply	261.43	264.26	256.69	253.11	258.43	275.87	277.17	281.16	271.00	276.52	272.42
EFT (ST & OT) per 1000 GWh of total supply	186.06	158.91	186.35	171.72	181.76	189.23	193.30	198.79	200.96	197.35	201.95
EFT (ST & OT) per 10,000 domestic customers	116.08	117.27	115.85	116.39	118.98	120.72	122.69	121.75	121.69	125.38	124.00
EFT (ST & OT) per $ millions of domestic revenue	6.25	6.08	5.85	5.65	5.57	5.61	5.49	5.55	4.98	5.05	4.82

PUB/MH I-16

Reference: Staffing

d) Please provide a schedule which indicates the total increase in salary wages, benefits and overhead [both OM&A and Capitalized] related to increase in EFT's for each of the years 1999/00 to 2013/14.

ANSWER:

The following table reflects Business Unit salaries, wages, overtime and benefits related to EFTs from 2004/05 to 2013/14:

Fiscal Year	Wages & Salaries	Overtime	Benefits	Total	EFTs
2004/05	$ 319,353	$ 33,822	$ 76,628	$ 429,804	5,870
2005/06	$ 330,834	$ 37,993	$ 79,188	$ 448,015	5,978
2006/07	$ 343,271	$ 38,869	$ 82,162	$ 464,302	5,988
2007/08	$ 357,690	$ 41,709	$ 85,865	$ 485,263	6,071
2008/09	$ 376,985	$ 45,447	$ 90,858	$ 513,290	6,276
2009/10	$ 404,576	$ 50,646	$ 97,226	$ 552,448	6,429
2010/11	$ 422,240	$ 50,655	$ 101,391	$ 574,286	6,594
2011/12	$ 448,032	$ 54,936	$ 107,247	$ 610,214	6,608
2012/13	$ 464,158	$ 60,953	$ 143,889	$ 669,000	6,678
2013/14 Forecast	$ 482,026	$ 59,898	$ 163,601	$ 705,525	6,958

PUB/MH I-16

Reference: Staffing

e) Please provide a schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized for each of the years 1999/00 to 2013/14.

ANSWER:

Please see the following schedule which reflects Business Unit* salary, wages and benefits from 2004/05 through 2013/14.

*Business Unit does not include allocations to capital and Centra Gas.

MANITOBA HYDRO
SALARIES & BENEFITS
(000's)

	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Forecast
Business Unit Salaries & Benefits*	$ 429,804	$ 448,015	$ 464,302	$ 485,263	$ 513,290	$ 552,448	$ 574,286	$ 610,214	$ 669,000	$ 705,525
Business Unit OM&A before capitalization	599,623	625,976	647,129	668,465	715,327	763,018	772,995	806,577	845,674	919,842
Salaries & Benefits as a % of OM&A	72%	72%	72%	73%	72%	72%	74%	76%	79%	77%
Domestic Revenue	938,954	983,653	1,023,613	1,074,580	1,126,812	1,144,891	1,200,381	1,191,117	1,341,009	1,377,596
% of Domestic Revenue	46%	46%	45%	45%	46%	48%	48%	51%	50%	51%
Business Uni Salaries & Benefits capitalized	$ 116,481	$ 127,260	$ 131,803	$ 142,648	$ 150,862	$ 166,914	$ 182,781	$ 203,411	$ 205,649	$ 236,296

*Salaries & Benefits includes salary, overtime and benefits.

PUB/MH I-17

Reference: 2013 Annual Report, Note 6, Page 79

Please provide an updated continuity schedule of construction work in process including the forecasted amounts to be spent on each major Generation and Transmission project for each of the years 2013 through 2016.

ANSWER:

Please see the table below.

MAJOR GENERATION & TRANSMISSION CONSTRUCTION IN PROGRESS		2013			2014			2015			2016		
(In Millions of Dollars)	OB	Addition	Transfer	Balance	Addition	Transfer	Balance	Addition	Transfer	Balance	Addition	Transfer	Balance
Wuskwatim	279	19	(298)	1	47	(45)	4	24	(9)	18	12	(30)	-
Keeyask - Generation	502	138	-	640	350	-	990	471	-	1 461	638	-	2 099
Conawapa - Generation	230	31	-	261	70	-	330	70	-	401	126	-	526
Kelsey Improvements & Upgrades	42	21	(31)	32	16	(42)	6	2	(8)	-	-	-	-
Kettle Improvements & Upgrades	2	1	-	3	3	(2)	4	8	(2)	10	24	(23)	11
Pointe du Bois	117	82	(24)	175	273	(445)	4	134	(135)	3	18	(6)	15
Gillam Redevelopment and Expansion Program (GREP)	(0)	-	-	-	-	-	-	27	(24)	3	30	(32)	2
Bipole III	141	109	-	250	274	-	524	592	(95)	1 021	921	(45)	1 897
Community Development Initiative	-	-	-	-	54	-	54	2	-	56	2	-	58
Riel 230/500kV Station	130	83	-	213	74	-	288	41	(329)	(1)	1	-	-
Firm Import Upgrades	-	-	-	-	-	-	-	11	-	11	9	(20)	-
Dorsey - US Border New 500kV Transmission Line	1	-	-	1	-	-	2	4	-	6	30	(6)	29
Total	1 444	484	(353)	1 575	1 161	(533)	2 205	1 385	(602)	2 989	1 811	(162)	4 638

*OB- Opening Balance

*Transfer – to Plant in Service

PUB/MH I-18

Reference: Attachment I IFF 13-1 DSM Spending

a) Please provide a schedule detailing the forecast electric DSM spending in the 2011 Power Smart Plan by program with the actual/forecast spending for 2012/13 and 2013/14.

ANSWER:

The following table outlines the forecast electric DSM spending for 2012/13 and 2013/14 from the 2011 Power Smart Plan and actual spending for 2012/13 broken out by program. Actual spending by program for 2013/14 is not yet available.

	*Forecast **	*Actual ***	*Forecast **
Power Smart Program	*2012/13*	*2012/13*	*2013/14*
	(Thousands of nominal $)		
RESIDENTIAL			
New Home Program	$512	$72	$549
Home Insulation Program	$1,143	$1,265	$1,052
Water and Energy Saver Program	$876	$775	$794
Lower Income Energy Efficiency Program	$397	$299	$386
Fridge Recycling Program	$2,231	$1,600	$2,144
	$5,158	*$4,012*	*$4,925*
COMMERCIAL			
Commercial Lighting Program	$5,639	$7,757	$5,086
Commercial Custom Measures Program	$155	$56	$168
Commercial Windows Program	$342	$925	$342
Commercial HVAC Program - Chiller	$143	$147	$146
City of Winnipeg Power Smart Agreement	$38	-$120	$0
Commercial Refrigeration Program	$201	$613	$208
Commercial Insulation Program	$718	$451	$718
Commercial Earth Power Program	$244	$265	$256
Commercial New Construction Program	$1,144	$116	$1,056
Commercial Building Optimization Program	$134	$92	$140
Internal Retrofit Program	$1,481	$811	$1,181
Commercial Kitchen Appliance Program	$126	$12	$146
Commercial Clothes Washers Program	$68	$59	$71
Network Energy Management Program	$240	$6	$266
CO2 Sensors	$5	$2	$5
Agricultural Heat Pad Program	$5	$1	$5
Commercial Parking Lot Controller Program	$4	$9	$0
Commercial Rinse & Save Program	$1	$0	$0
	$10,689	*$11,201*	*$9,794*
INDUSTRIAL			
Performance Optimization Program	$2,736	$2,741	$2,736
Emergency Preparedness Program	$727	$0	$1,532
	$3,463	*$2,741*	*$4,268*
LOAD MANAGEMENT			
Curtailable Rate Program	$5,952	$5,751	$5,952
CUSTOMER SELF-GENERATION			
BioEnergy Optimization Program	$4,215	$348	$4,342
Program Support	$3,932	$3,336	$3,931
Contingency	$1,000	$0	$1,500
	$4,932	*$3,336*	*$5,431*
Total Electric DSM Spending	**$34,409**	**$27,389**	**$34,712**
** Source: 2011 Power Smart Plan*			
*** Source: 2012/13 Power Smart Annual Review*			
Figures may not add due to rounding			

PUB/MH I-18

Reference: Attachment I IFF 13-1 DSM Spending

b) Please provide an explanation of the Planned Additional Capacity and Energy arising from DSM indicated on page 6 of IFF13-1 and indicate which Power Smart Plan this is based on.

ANSWER:

The Planned Additional Capacity and Energy arising from DSM indicated on page 6 of IFF13-1 is based on the 2013-16 Power Smart Plan.

The Planned Additional Capacity is the additional MW (at the point of generation) from conservation programs (excluding the Curtailable Rates Program and the Bioenergy Optimization Program which are not included in the Corporation's resource planning process) as shown in the highlighted cells in Appendix A.1 of the 2013-16 Power Smart Plan (attached).

The Planned Additional Energy is the additional GW.h (at the point of generation) from all programs as shown in the highlighted cells in Appendix A.2 of the 2013-16 Power Smart Plan (attached).

ELECTRIC DSM

APPENDIX A.1

2013 - 2016 Power Smart Plan
Annual Capacity Savings (MW)

	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	2027/28		MW at Generation 2027/28
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	1.7	3.3	4.7	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6		6.4
Water and Energy Saver Program	0.6	1.1	1.4	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2		1.3
Lower Income Energy Efficiency Program	1.0	1.9	2.7	3.5	3.5	3.5	3.5	3.3	3.1	3.0	2.6	2.4	2.2	2.1	2.1		2.4
Refrigerator Retirement Program	1.7	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	0.9	0.2	0.2	0.1		0.1
Subtotal	4.9	8.7	11.1	12.7	12.7	12.7	12.7	12.5	12.3	12.2	11.8	10.0	9.2	9.1	9.0	3%	10.2
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.2	0.4	0.5	0.7	0.9	1.1	1.3	1.4	1.6	1.8	2.0	2.2	2.3	2.5	2.7		3.1
Power Smart PAYS Financing	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6		1.8
Residential Earth Power Loan	0.3	0.7	1.0	1.4	1.8	2.3	2.7	3.2	3.7	4.2	4.7	5.3	5.3	5.3	5.3		6.0
Subtotal	0.7	1.4	2.0	2.7	3.4	4.1	4.8	5.5	6.3	7.1	7.9	8.8	9.0	9.3	9.6	3%	10.9
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	6.3	11.9	16.9	21.0	25.2	29.3	33.1	36.7	40.1	43.2	44.6	46.0	47.1	48.1	49.1		55.9
Commercial Building Envelope - Windows Program	0.7	1.3	1.7	1.9	2.2	2.5	2.8	3.1	3.3	3.5	3.8	4.0	4.2	4.5	4.7		5.3
Commercial Buliding Envelope - Insulation Program	0.8	1.4	1.9	2.2	2.5	2.8	3.0	3.2	3.4	3.6	3.7	3.9	4.0	4.1	4.2		4.8
Commercial Earth Power Program	0.4	0.8	1.2	1.6	2.0	2.4	2.8	3.1	3.5	4.0	4.4	4.8	5.2	5.7	6.1		6.9
Commercial HVAC Program - Chiller	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
Commercial HVAC Program - CO2 Sensors	0.1	0.2	0.3	0.4	0.5	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.7	0.7		0.8
Commercial Custom Measures Program	0.2	0.5	0.7	1.0	1.2	1.5	1.8	2.0	2.3	2.5	2.8	3.0	3.3	3.6	3.8		4.4
Commercial Building Optimization Program	0.2	0.3	0.5	0.7	1.0	1.2	1.4	1.6	1.8	2.1	2.3	2.5	2.6	2.7	2.9		3.3
New Buildings Program	2.5	5.7	9.2	13.8	17.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7		24.8
Commercial Refrigeration Program	0.1	0.3	0.5	0.7	0.9	1.1	1.3	1.5	1.8	2.1	2.4	2.7	2.7	2.7	2.7		3.1
Commercial Kitchen Appliance Program	0.4	1.0	1.7	2.0	2.1	2.1	2.1	2.1	2.1	2.1	1.5	0.9	0.3	0.2	0.1		0.2
Network Energy Management Program	0.2	0.3	0.5	0.5	0.6	0.8	0.6	0.4	0.4	0.2	0.0	0.0	0.0	0.0	0.0		0.0
Internal Retrofit Program	0.3	0.4	0.5	0.5	0.6	0.8	0.9	1.1	1.2	1.3	1.4	1.4	1.3	1.3	1.2		1.4
Subtotal	12.1	24.1	35.5	46.2	56.6	66.8	72.2	77.4	82.4	87.3	89.3	91.8	93.3	95.3	97.2	32%	110.9
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6		0.7
Subtotal	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0%	0.7
INDUSTRIAL																	
Performance Optimization Program	2.0	4.0	6.0	8.1	10.1	12.1	14.2	16.2	18.2	20.2	22.3	24.3	26.3	28.3	30.4		33.4
Subtotal	2.0	4.0	6.0	8.1	10.1	12.1	14.2	16.2	18.2	20.2	22.3	24.3	26.3	28.3	30.4	10%	33.4
CONSERVATION SUBTOTAL	19.8	38.3	54.9	69.9	83.0	96.0	104.2	112.0	119.7	127.2	131.8	135.4	138.4	142.6	146.7	49%	166.1
LOAD MANAGEMENT																	
Curtailable Rates Program	146.4	146.4	146.4	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3		162.0
LOAD MANAGEMENT SUBTOTAL	146.4	146.4	146.4	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	147.3	49%	162.0
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	1.2	2.6	4.0	5.1	5.9	6.7	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3		8.0
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	1.2	2.6	4.0	5.1	5.9	6.7	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	2%	8.0
Program Impacts (at meter)	168	187	205	222	236	250	259	267	274	282	286	290	293	297	301	100%	
Program Impacts (at generation)	185	207	228	247	263	278	288	297	306	314	319	323	327	331	336		
Codes, Standards & Regulations (at meter)	14	28	46	71	82	90	99	107	115	120	120	122	127	132	135		
Codes, Standards & Regulations (at generation)	16	31	52	80	93	103	113	122	132	137	137	140	144	151	154		
POWER SMART 2013 to 2027 Impacts (at meter)	181	215	251	293	318	340	358	374	390	402	407	412	420	429	436		
POWER SMART 2013 to 2027 Impacts (at generation)	201	239	280	327	356	381	401	419	437	451	456	463	471	482	490		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	205	205	205	204	203	202	201	200	200	196	194	190	180	175	168		
Incentive Based Program Impacts (at generation)	230	230	231	229	228	228	226	225	224	221	218	214	202	196	189		
Customer Service Initiatives Program Impacts (at meter)	8	8	8	8	8	8	8	8	8	8	8	8	8	7	6		
Customer Service Initiatives Program Impacts (at generation)	9	9	9	9	9	9	9	9	9	9	9	9	9	8	7		
Discontinued Programs (at meter)	41	41	29	29	28	28	28	28	28	27	26	26	25	25	25		
Discontinued Programs (at generation)	46	46	32	32	32	32	32	32	32	31	30	29	29	29	28		
Impacts of Codes & Standards (at meter)	116	116	116	116	116	116	116	116	116	116	116	116	116	116	116		
Impacts of Codes & Standards (at generation)	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132		
TOTAL MW (at meter)	551	584	609	649	673	695	711	726	741	749	750	752	748	752	751		
TOTAL MW (at generation)	619	656	685	730	757	782	800	817	835	843	845	847	843	847	846		

Note: May not add up due to rounding.

ELECTRIC DSM

APPENDIX A.2

2013 - 2016 Power Smart Plan
Annual Energy Savings (GW.h)

	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	2027/28		GW.h at Generation 2027/28
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	3.2	6.0	8.6	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5		11.9
Water and Energy Saver Program	2.9	5.8	6.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8		6.6
Lower Income Energy Efficiency Program	2.4	4.7	6.9	8.7	8.7	8.7	8.7	8.3	7.9	7.4	6.5	6.0	5.7	5.3	5.3		6.1
Refrigerator Retirement Program	15.2	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	7.7	1.7	1.7	0.5		0.6
Subtotal	23.7	38.2	44.0	46.7	46.7	46.7	46.7	46.3	45.8	45.4	44.5	30.0	23.7	23.3	22.1	3%	25.2
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.7	3.1	3.4	3.8	4.1	4.5	4.8	5.1		5.9
Power Smart PAYS Financing	0.3	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.2	2.4	2.6	2.8	3.0	3.2	3.4		3.9
Residential Earth Power Loan	1.5	2.9	4.4	6.0	7.7	9.5	11.4	13.3	15.4	17.5	19.8	22.1	22.1	22.1	22.1		25.2
Subtotal	2.1	4.2	6.3	8.5	10.8	13.1	15.5	18.0	20.7	23.4	26.2	29.1	29.6	30.2	30.7	4%	35.0
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	22.7	43.2	61.3	75.4	90.7	105.4	119.2	132.0	144.1	155.5	160.2	165.6	169.3	172.9	176.4		201.1
Commercial Building Envelope - Windows Program	1.7	3.2	4.3	4.9	5.6	6.4	7.1	7.7	8.4	9.0	9.6	10.1	10.7	11.3	11.8		13.5
Commercial Buliding Envelope - Insulation Program	1.9	3.5	4.8	5.6	6.4	7.1	7.8	8.3	8.8	9.2	9.5	9.9	10.2	10.5	10.8		12.3
Commercial Earth Power Program	1.6	3.3	4.9	6.6	8.2	9.9	11.5	13.2	14.8	16.6	18.3	20.1	21.9	23.6	25.4		29.0
Commercial HVAC Program - Chiller	1.1	2.3	3.5	5.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5		7.4
Commercial HVAC Program - CO2 Sensors	0.1	0.2	0.4	0.5	0.7	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.0	1.0		1.1
Commercial Custom Measures Program	0.9	1.8	2.8	3.7	4.7	5.6	6.6	7.5	8.5	9.5	10.5	11.5	12.4	13.4	14.4		16.4
Commercial Building Optimization Program	0.9	1.6	2.5	3.6	4.7	5.8	6.8	8.0	9.2	10.5	11.4	12.3	13.1	13.6	14.2		16.1
New Buildings Program	10.3	22.6	35.9	51.9	66.5	81.7	81.7	81.7	81.7	81.7	81.7	81.7	81.7	81.7	81.7		93.2
Commercial Refrigeration Program	1.3	2.6	4.1	5.8	7.6	9.4	11.4	13.5	15.8	18.4	21.1	24.2	24.2	24.2	24.2		27.5
Commercial Kitchen Appliance Program	0.4	0.9	1.6	2.0	2.2	2.2	2.2	2.2	2.2	2.2	1.8	1.3	0.8	0.6	0.4		0.5
Network Energy Management Program	0.6	0.9	1.4	1.3	1.7	2.0	1.7	1.0	1.0	0.6	0.0	0.0	0.0	0.0	0.0		0.0
Internal Retrofit Program	2.4	3.0	3.3	2.9	3.7	4.7	5.6	6.5	7.4	8.3	8.4	8.4	8.3	8.2	8.1		9.2
Subtotal	45.9	89.2	130.6	169.2	209.3	247.7	268.9	289.2	309.4	328.9	340.1	352.7	360.1	367.5	374.8	55%	427.3
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	0.2	0.4	0.6	0.8	0.9	1.1	1.2	1.3	1.4	1.6	1.7	1.8	1.9	2.1	2.2		2.5
Subtotal	0.2	0.4	0.6	0.8	0.9	1.1	1.2	1.3	1.4	1.6	1.7	1.8	1.9	2.1	2.2	0%	2.5
INDUSTRIAL																	
Performance Optimization Program	12.9	25.8	38.7	51.6	64.5	77.4	90.3	103.2	116.1	129.0	141.9	154.8	167.7	180.6	193.5		212.9
Subtotal	12.9	25.8	38.7	51.6	64.5	77.4	90.3	103.2	116.1	129.0	141.9	154.8	167.7	180.6	193.5	28%	212.9
CONSERVATION SUBTOTAL	84.8	157.8	220.2	276.8	332.2	385.9	422.6	458.1	493.4	528.2	554.3	568.4	583.0	603.6	623.4	91%	702.9
LOAD MANAGEMENT																	
Curtailable Rates Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
LOAD MANAGEMENT SUBTOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%	0.0
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	10.9	22.6	34.9	44.6	51.8	58.7	63.4	63.4	63.4	63.4	63.4	63.4	63.4	63.4	63.4		69.7
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	10.9	22.6	34.9	44.6	51.8	58.7	63.4	63.4	63.4	63.4	63.4	63.4	63.4	63.4	63.4	9%	69.7
Program Impacts (at meter)	96	180	255	321	384	445	486	521	557	592	618	632	646	667	687	100%	
Program Impacts (at generation)	108	204	288	362	433	501	548	588	628	667	696	712	728	751	773		
Codes, Standards & Regulations (at meter)	58	116	194	291	350	400	448	495	541	566	580	601	629	661	683		
Codes, Standards & Regulations (at generation)	66	132	222	332	399	456	511	565	617	645	661	685	718	754	779		
POWER SMART 2013 to 2027 Impacts (at meter)	154	296	450	612	734	845	934	1,017	1,098	1,158	1,197	1,232	1,276	1,328	1,370		
POWER SMART 2013 to 2027 Impacts (at generation)	174	335	510	694	833	958	1,059	1,153	1,245	1,312	1,357	1,396	1,445	1,505	1,552		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	918.3	917.9	919.0	916.6	914.1	911.4	907.6	904.9	900.9	867.9	847.7	823.4	760.2	719.6	683.4		
Incentive Based Program Impacts (at generation)	1,031.5	1,031.0	1,032.3	1,029.6	1,026.7	1,023.7	1,019.4	1,016.3	1,011.7	975.4	953.1	926.3	854.9	809.6	768.8		
Customer Service Initiatives Program Impacts (at meter)	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	21.9	21.3	17.5	17.5	16.1	12.1		
Customer Service Initiatives Program Impacts (at generation)	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.0	24.3	19.9	19.9	18.4	13.8		
Discontinued Programs (at meter)	291.7	255.3	233.4	231.5	228.8	226.9	226.5	226.5	226.5	215.2	206.6	198.1	187.4	184.8	180.3		
Discontinued Programs (at generation)	330.4	288.8	263.9	261.7	258.7	256.5	256.0	256.0	256.0	243.1	233.4	223.7	211.4	208.5	203.4		
Impacts of Codes & Standards (at meter)	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4	505.4		
Impacts of Codes & Standards (at generation)	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5	575.5		
TOTAL GW.h (at meter)	1,892	1,997	2,130	2,288	2,405	2,511	2,596	2,676	2,753	2,768	2,778	2,777	2,746	2,754	2,751		
TOTAL GW.h (at generation)	2,137	2,256	2,407	2,586	2,719	2,839	2,935	3,026	3,113	3,131	3,143	3,142	3,107	3,117	3,113		

Note: May not add up due to rounding

PUB/MH I-19

Reference: Attachment I IFF 13-1 Alternative Scenario

a) Please provide an alternative 20-year IFF MH13-1 scenario that reflects no additional spending on Conawapa commencing in 2014/15 and indicate the financial targets for electric operations and annual average rate increases required to attain 75:25 by 2032/33. Sunk Costs are to remain deferred during the 20-year forecast.

ANSWER:

The requested scenario is not available within the time frame for this Application. However, please refer to MH-Exhibit #104-12.3 filed on April 11, 2014 in the NFAT hearing, which provides a financial and rate analysis for development plan #5 (K19/Gas/750), containing the revised capital costs for Keeyask and various levels of Demand Side Management investment. The filing of April 11, 2014 is based on planning assumptions similar to those contained in MH13.

PUB/MH I-19

Reference: Attachment I IFF 13-1 Alternative Scenario

b) Please provide alternative 20 year IFF MH13-1 scenarios that reflects the inclusion of Base Capital Expenditures and Bipole III, but excluding all other new Major Generation and Transmission Projects. Sunk costs are to remain deferred during the 20-year forecast.

ANSWER:

Manitoba Hydro is not able to provide the requested scenario, as planning for new major generation and transmission projects is required to meet its firm load commitments.

PUB/MH I-19

Reference: Attachment I IFF 13-1 Alternative Scenario

c) Please isolate the annual revenue requirement for Bipole III indicated in MH13-1.

ANSWER:

This information is expected to be provided in the response to Undertaking 49 at the NFAT hearing.

PUB/MH I-20

Reference: 2012 GRA PUB/MH II-105(a)

a) Please file an updated version of the tables from 2012 GRA PUB/MH II-105(a) to include 2012/13 and 2013/14.

ANSWER:

The following table is an update to the table provided in response to PUB/MH II-105(a) from 2012 GRA for 2012/13 and 2013/14. Manitoba Hydro is unable to provide individual or recent wind farm generation data due to confidentiality agreement prohibitions. Therefore, Q4 and the Annual total from 2013/14 in the table below combine Wind Purchases and Imports.

<table>
<tr><th></th><th>Actual Results (GWh)</th><th>Hydraulic Generation</th><th>Thermal Generation</th><th>Wind Purchases</th><th>Imports</th></tr>
<tr><td rowspan="5">2013/14</td><td>Q1</td><td>8536</td><td>24</td><td>228</td><td>38</td></tr>
<tr><td>Q2</td><td>9189</td><td>20</td><td>154</td><td>39</td></tr>
<tr><td>Q3</td><td>8990</td><td>36</td><td>257</td><td>135</td></tr>
<tr><td>Q4</td><td>8546</td><td>51</td><td colspan="2">725</td></tr>
<tr><td>Annual</td><td>35261</td><td>131</td><td colspan="2">1576</td></tr>
<tr><td rowspan="5">2012/13</td><td>Q1</td><td>7257</td><td>5</td><td>218</td><td>124</td></tr>
<tr><td>Q2</td><td>9028</td><td>27</td><td>182</td><td>4</td></tr>
<tr><td>Q3</td><td>8136</td><td>40</td><td>222</td><td>207</td></tr>
<tr><td>Q4</td><td>8726</td><td>11</td><td>229</td><td>194</td></tr>
<tr><td>Annual</td><td>33147</td><td>83</td><td>851</td><td>528</td></tr>
</table>

PUB/MH I-20

Reference: 2013 GRA PUB/MH II-105(a)

b) File a similar forecast tabulation for 2014/15 and 2015/16.

ANSWER:

The energy data for fiscal years, 2014/15 and 2015/16, are given as:

Fiscal Year	Hydraulic Generation (GWh)	Thermal Generation (GWh)	Wind Purchases (GWh)	Import (GWh)
2014/15	34321	132	898	788
2015/16	30910	348	907	1377

PUB/MH I-21

Reference: Load Forecast

Please file the 2014 Load Forecast or as a minimum provide updated monthly actuals for 2012/13 and 2013/14 and monthly forecasts for 2014/15 and 2015/16.

ANSWER:

The 2013 Load Forecast is the most current forecast available. The following provides the monthly Gross Firm actuals for the 2012/13 and 2013/14 fiscal year to date and the monthly forecast of Gross Firm Energy for 2014/15 and 2015/16 fiscal years based upon the 2013 Load Forecast.

Gross Firm @ Generation Monthly Actuals (GW.h)	
Month	**Actuals**
2012 APR	1,802
2012 MAY	1,698
2012 JUN	1,688
2012 JUL	1,869
2012 AUG	1,727
2012 SEP	1,606
2012 OCT	1,941
2012 NOV	2,265
2012 DEC	2,665
2013 JAN	2,766
2013 FEB	2,342
2013 MAR	2,383
2013 APR	2,041
2013 MAY	1,754
2013 JUN	1,650
2013 JUL	1,766
2013 AUG	1,725
2013 SEP	1,657
2013 OCT	1,914
2013 NOV	2,258
2013 DEC	2,884
2014 JAN	2,895
2014 FEB	2,553
2014 MAR	2,345

Gross Firm @ Generation Monthly Forecast (GW.h)	
Month	**2013 Forecast**
2014 APR	1,947
2014 MAY	1,845
2014 JUN	1,764
2014 JUL	1,877
2014 AUG	1,840
2014 SEP	1,764
2014 OCT	1,989
2014 NOV	2,267
2014 DEC	2,750
2015 JAN	2,820
2015 FEB	2,426
2015 MAR	2,387
2015 APR	1,972
2015 MAY	1,869
2015 JUN	1,787
2015 JUL	1,902
2015 AUG	1,865
2015 SEP	1,788
2015 OCT	2,015
2015 NOV	2,296
2015 DEC	2,786
2016 JAN	2,857
2016 FEB	2,458
2016 MAR	2,418

PUB/MH I-22

Reference: 2012 GRA PUB/MH II-087 (p.1 to 5)

a) Provide monthly hydraulic generation for 2012/13 and 2013/14.

ANSWER:

In the table below, please find Manitoba Hydro's monthly hydraulic gross generation for 2012/13 and 2013/14.

Month	Hydraulic Gross Generation (GWh)
Apr-12	2,226
May-12	2,466
Jun-12	2,565
Jul-12	3,184
Aug-12	3,129
Sep-12	2,715
Oct-12	2,549
Nov-12	2,727
Dec-12	2,859
Jan-13	2,987
Feb-13	2,696
Mar-13	3,044
Apr-13	2,685
May-13	2,903
Jun-13	2,948
Jul-13	3,214
Aug-13	3,270
Sep-13	2,705
Oct-13	3,088
Nov-13	2,848
Dec-13	3,055
Jan-14	2,947
Feb-14	2,646
Mar-14	2,953

PUB/MH I-22

Reference: 2012 GRA PUB/MH II-087 (p.1 to 5)

b) Provide monthly watershed flow data for 2012/13 and 2013/14.

ANSWER:

The table below provides the average monthly flows for major watersheds for 2012/13 and 2013/14.

	Monthly Average Flow in CMS					
	Winnipeg Rvr. @ Great Falls	Red River @ Lockport	Sask River @ Grand Rapids	Nelson Rvr. @ Kelsey	Burntwood Rvr Near Thomp	Nelson Rvr @ Kettle GS
2012/Apr	606	264	717	1773	943	2834
2012/May	614	261	787	1831	924	3072
2012/Jun	927	268	799	1964	1150	3234
2012/Jul	1261	301	1136	2604	1108	3886
2012/Aug	903	134	1247	2772	1040	3993
2012/Sep	681	87	675	2283	1040	3708
2012/Oct	540	96	492	2060	1051	3203
2012/Nov	717	65	743	2410	1097	3619
2012/Dec	773	47	799	2689	1137	3624
2013/Jan	776	39	850	2699	1053	3806
2013/Feb	875	37	854	2647	1029	3713
2013/Mar	951	90	867	2559	1004	3795
2013/Apr	707	302	645	2382	1006	3538
2013/May	954	1525	490	2427	1065	3639
2013/Jun	1816	962	1000	2481	933	3718
2013/Jul	1688	632	1807	3670	774	4464
2013/Aug	1107	281	1285	3822	730	4863
2013/Sep	1007	153	555	2809	941	3907
2013/Oct	1045	163	720	2599	1154	3943
2013/Nov	860	109	742	2606	1078	3856
2013/Dec	820	96	948	2704	1131	3810
2014/Jan	839	75	947	2563	1034	3632
2014/Feb	988	57	962	2433	1019	3542
2014/Mar	1000	79	948	2403	1011	3568

CMS- Cubic meters per second

PUB/MH I-22

Reference: 2012 GRA PUB/MH II-087 (p.1 to 5)

c) Provide monthly Lake Winnipeg water level data for 2012/13 and 2013/14.

ANSWER:

The table below provides the Lake Winnipeg wind eliminated elevation (meters) for the 1st of each month through the period from April 1, 2012 to March 31, 2014.

	1st of the month Elev in M Lake Winnipeg
2012/Apr	217.44
2012/May	217.53
2012/Jun	217.66
2012/Jul	217.80
2012/Aug	217.84
2012/Sep	217.78
2012/Oct	217.66
2012/Nov	217.58
2012/Dec	217.55
2013/Jan	217.50
2013/Feb	217.46
2013/Mar	217.43
2013/Apr	217.41
2013/May	217.39
2013/Jun	217.63
2013/Jul	217.90
2013/Aug	217.92
2013/Sep	217.81
2013/Oct	217.70
2013/Nov	217.62
2013/Dec	217.56
2014/Jan	217.51
2014/Feb	217.50
2014/Mar	217.51

PUB/MH I-23

Reference: 2014 GRA Table (a) & (b)

a) Please confirm that Lake Winnipeg water levels have remained within 1.5 ft. (0.45 m) of the upper license limit during the last quarter of 2013/14.

ANSWER:

The table below provides average monthly wind eliminated Lake Winnipeg water levels for the last quarter of 2013/14. The upper license limit of operating range on Lake Winnipeg is 217.93 m.

Month	Lake Winnipeg (m)	Difference from upper license limit (m)
Jan-2014	217.50	0.43
Feb-2014	217.51	0.42
Mar-2014	217.51	0.42

PUB/MH I-23

Reference: 2014 GRA Table (a) & (b)

b) Please confirm that Manitoba Hydro's hydraulic generation for the first 9 months of 2013/14 was 26,700 GWh and that the total for 11 months was about 32,300 GWh.

ANSWER:

Manitoba Hydro's hydraulic gross generation for the first 9 months of 2013/14 was 26,715 GWh and the total for 11 months was 32,308 GWh.

PUB/MH I-23

Reference: 2014 GRA Table (a) & (b)

c) Please further confirm that the likely year-end total for 2013/14 could be 35,000 GWh (well above average).

ANSWER:

Manitoba Hydro's hydraulic gross generation at year end 2013/14 was 35,261 GWh. The average is 31,000 GWh.

PUB/MH I-24

Reference: 2014 GRA Table (c)

a) Please confirm that watershed flows, except for the Red River, are above average and the Lower Nelson flows are about 85% of maximum useful flows.

ANSWER:

The watershed flows from Table (c) of Appendix 7 of the Application can be characterized as follows:

- Winnipeg River at Great Falls GS – Below average
- Red River at Lockport – Average
- Saskatchewan River at Grand Rapids – Above average
- Nelson River at Kelsey GS - Above average
- Burntwood River Near Thompson – Above average
- Nelson River at Kettle GS - Above average.

Flows on the Nelson River are currently above average reflecting the above average storage conditions and outflows from Lake Winnipeg. These flows on the lower Nelson are approximately 75% of the flow at which spillage commences at Kettle GS, Long Spruce GS and Limestone GS.

PUB/MH I-24

Reference: 2014 GRA Table (c)

b) Please confirm that overall watershed spring runoffs are predicted to be well above average in 2014/15.

ANSWER:

Assuming normal or above normal spring precipitation occurs, Manitoba Hydro's forecast of overall spring runoff is above average.

Should spring precipitation be below normal, spring runoff will be below normal. Manitoba Hydro estimates that there is a 40% probability that spring runoff will be below average.

PUB/MH I-25

Reference: Appendix 1 IFF 13 Section 14.0

Confirm that IFF13-1 predicts 2013/14 and 2014/15 water rentals to be $125 M and $123 M respectively, which compares to average-year water rentals of $111 M.

ANSWER:

Confirmed.

PUB/MH I-26

Reference: NFAT PUB/MH 1-009 Revised (14 pages)

Please refile PUB/MH 1-009 Revised to include all of 2013/14.

ANSWER:

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Apr-08	144	17,554	1,331,013	75.82						
	155	21,063	1,081,235	51.33						
	224	175,438	9,140,552	52.10						
	259	523	33,718	64.47						
	269				674,057	38,710,758	57.43			
								498	56,930	114.32
May-08	35	81,724	3,401,427	41.62						
	144	17,600	1,282,846	72.89						
	155	21,120	1,087,816	51.51						
	224	175,500	9,220,917	52.54						
	259	396	28,906	72.99						
	269				699,599	31,370,396	44.84			
								500	47,713	95.43
Jun-08	33	19,490	697,220	35.77						
	34	14,617	522,897	35.77						
	35	73,902	3,379,308	45.73						
	144	16,407	1,233,972	75.21						
	155	19,866	1,068,185	53.77						
	224	162,001	8,977,792	55.42						
	259	475	31,630	66.59						
	269				494,860	24,520,507	49.55			
								4,897	744,598	152.05
Jul-08	33	70,400	2,535,990	36.02						
	34	52,800	1,901,992	36.02						
	35	96,900	5,633,561	58.14						
	144	18,380	1,375,994	74.86						
	155	22,055	1,157,066	52.46						
	224	183,686	9,799,722	53.35						
	259	366	28,736	78.51						
	269				799,886	37,260,178	46.58			
								1,106	134,304	121.43

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Aug-08	33	67,200	2,507,804	37.32						
	34	50,400	1,880,853	37.32						
	35	108,900	4,898,303	44.98						
	144	16,788	1,314,433	78.30						
	155	20,160	1,125,657	55.84						
	224	168,000	9,583,228	57.04						
	259	383	29,647	77.41						
	269				859,734	34,817,392	40.50			
								2,356	254,097	107.85
Sep-08	33	19,210	705,067	36.70						
	34	14,407	536,282	37.22						
	35	106,950	3,584,400	33.51						
	144	17,428	1,354,954	77.75						
	155	21,120	1,159,702	54.91						
	224	173,640	9,762,961	56.23						
	259	357	28,666	80.30						
	269				795,097	23,433,570	29.47			
								492	52,767	107.25
Oct-08	35	111,600	4,153,724	0.04						
	144	18,400	1,633,552	0.09						
	155	22,080	1,373,405	0.06						
	224	184,000	11,635,701	0.06						
	259	384	29,688	0.08						
	269				694,487	24,144,820	34.77			
								1,199	82,222	68.58
Nov-08	144	15,994	1,465,977	91.66						
	155	19,200	1,265,540	65.91						
	224	160,000	10,819,982	67.62						
	259	642	39,378	61.34						
	269				614,926	24,241,549	39.42			
								300	8,925	29.75
Dec-08	144	18,381	1,642,812	89.38						
	155	22,080	1,382,550	62.62						
	224	158,320	10,639,551	67.20						
	259	854	52,411	61.37						
	269				197,415	13,641,499	69.10			
								48,883	1,682,653	34.42
Jan-09	144	17,600	1,595,364	90.65						
	155	21,117	1,352,687	64.06						
	224	161,779	10,888,078	67.30						
	259	1,192	68,796	57.71						
	269				123,830	7,442,112	60.10			
								61,915	2,559,045	41.33

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Feb-09	144	16,000	1,506,201	94.14						
	155	19,200	1,301,862	67.81						
	224	156,110	10,944,203	70.11						
	259	833	50,946	61.16						
	269				173,600	8,571,553	49.38			
								6,749	344,517	51.05
Mar-09	144	17,568	1,623,272	92.40						
	155	21,120	1,378,863	65.29						
	224	172,308	11,550,659	67.03						
	259	833	50,946	61.16						
	269				194,748	8,194,807	42.08			
								19,095	719,180	37.66
Apr-09	144	17,541	1,536,031	87.57						
	155	21,049	1,303,354	61.92						
	224	175,418	11,070,661	63.11						
	259	639	40,227	62.95						
	269				466,954	11,164,381	23.91			
								500	61,317	122.63
May-09	33	47,217	629,505	13.33						
	34	35,430	469,493	13.25						
	35	52,174	1,046,940	20.07						
	144	16,588	1,445,711	87.15						
	155	9,928	587,038	59.13						
	224	287,476	11,604,608	40.37						
	259	481	35,977	74.80						
	269				448,634	10,411,481	23.21			
								813	33,550	41.27
Jun-09	33	86,711	2,357,030	27.18						
	34	6,588	1,805,106	274.00						
	35	7,200	308,462	42.84						
	144	17,600	1,617,138	91.88						
	155	16,078	758,261	47.16						
	224	303,767	13,019,826	42.86						
	259	461	35,204	76.36						
	269				434,693	11,286,387	25.96			
								1,851	32,292	17.45
Jul-09	33	119,319	2,928,700	24.55						
	34	89,632	2,197,587	24.52						
	35	2,250	58,679	26.08						
	144	18,400	1,562,504	84.92						
	155	14,731	680,137	46.17						
	224	358,969	12,602,626	35.11						
	259	394	32,545	82.60						
	269				521,232	10,303,089	19.77			
								1,851	160,870	86.91

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Aug-09	33	132,126	3,214,448	24.33						
	34	9,063	2,410,700	265.99						
	35	1,650	43,737	26.51						
	144	16,800	1,463,074	87.09						
	155	13,800	653,061	47.32						
	224	362,391	12,705,102	35.06						
	259	425	33,766	79.45						
	269				512,427	11,298,361	22.05			
								495	34,035	68.76
Sep-09	33	28,367	961,127	33.88						
	34	21,352	724,358	33.92						
	144	16,888	1,437,114	85.10						
	155	15,644	682,116	43.60						
	224	176,859	9,980,692	56.43						
	259	320	29,621	92.57						
	269				721,192	13,904,731	19.28			
								437	41,672	95.36
Oct-09	35	77,706	2,358,613	30.35						
	144	17,358	1,480,174	85.27						
	155	10,416	596,508	57.27						
	224	173,876	10,162,359	58.45						
	269				866,924	20,512,094	23.66			
	345	527	37,820	71.76						
								0	0	0.00
Nov-09	144	16,800	1,410,645	83.97						
	155	10,080	572,268	56.77						
	224	168,000	9,756,683	58.08						
	269				652,817	15,208,111	23.30			
	345	503	36,853	73.27						
								12,766	291,376	22.82
Dec-09	144	18,337	1,510,887	82.40						
	155	11,002	602,185	54.73						
	224	178,620	10,045,274	56.24						
	269				180,369	7,233,228	40.10			
	345	785	50,708	64.60						
								96,983	2,446,474	25.23
Jan-10	144	16,800	1,420,784	84.57						
	155	10,080	576,381	57.18						
	224	157,869	9,449,930	59.86						
	269				294,690	12,031,863	40.83			
	345	1,004	61,779	61.53						
								78,020	1,928,233	24.71

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Feb-10	144	1,600	1,344,224	840.14						
	155	9,600	550,946	57.39						
	224	159,086	9,384,649	58.99						
	269				238,998	9,492,286	39.72			
	345	948	58,242	61.44						
								43,325	1,060,605	24.48
Mar-10	144	18,389	1,469,898	79.93						
	155	11,033	585,515	53.07						
	224	183,900	9,935,043	54.02						
	269				496,047	14,153,374	28.53			
	345	684	46,670	68.23						
								1,107	15,147	13.68
Apr-10	144	17,111	1,371,751	80.17						
	155	10,308	556,029	53.94						
	224	171,379	9,453,481	55.16						
	269				502,793	11,922,854	23.71			
	345	455	34,287	75.36						
								1,175	19,334	16.45
May-10	35	53,700	1,874,870	34.91						
	155	10,080	573,486	56.89						
	224	167,000	9,737,141	58.31						
	269				194,547	7,894,406	40.58			
	345	357	25,898	72.54						
								122,179	2,634,286	21.56
Jun-10	33	37,900	1,460,750	38.54						
	34	28,495	1,098,260	38.54						
	35	82,651	2,570,108	31.10						
	155	10,560	599,904	56.81						
	224	171,412	10,026,035	58.49						
	269				461,086	13,150,740	28.52			
	273	4	515	128.75						
	345	356	25,910	72.78						
								5,241	60,258	11.50
Jul-10	33	56,900	2,127,711	37.39						
	34	42,672	1,595,671	37.39						
	35	106,253	3,410,437	32.10						
	155	10,511	580,139	55.19						
	224	175,324	9,869,728	56.29						
	269				738,392	19,473,860	26.37			
	345	424	28,688							
								3,755	218,864	58.29

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Aug-10	33	55,590	2,149,228	38.66						
	34	41,765	1,614,724	38.66						
	35	110,249	3,928,184	35.63						
	155	10,403	595,507	57.24						
	224	173,783	10,146,551	58.39						
	269				748,854	22,321,983	29.81			
	345	374	25,689	68.69						
								1,660	56,302	33.92
Sep-10	33	25,000	935,573	37.42						
	34	18,600	696,067	37.42						
	35	97,125	2,254,630	23.21						
	155	21,600	801,336	37.10						
	224	175,000	9,865,613	56.37						
	269				656,585	13,486,571	20.54			
	345	395	28,650	72.53						
								1,654	56,879	34.39
Oct-10	33	639	23,658	37.02						
	34	484	17,919	37.02						
	35	107,046	2,616,994	24.45						
	155	10,069	557,502	55.37						
	224	167,819	9,501,757	56.62						
	269				788,954	18,110,622	22.96			
	345	389	27,656	71.10						
								2,192	100,023	45.63
Nov-10	33									
	34									
	35									
	155	10,560	580,559	54.98						
	224	167,297	9,553,709	57.11						
	269									
	345	545	37,269	68.38						
	355				547,247	12,127,472	22.16			
								10,623	554,475	52.20
Dec-10	155	11,040	580,475	52.58						
	224	153,546	8,774,516	57.15						
	345	786	51,282	65.24						
	355				303,045	8,939,053	29.50			
								25,018	682,532	27.28
Jan-11	155	10,080	548,832	54.45						
	224	112,447	7,386,342	65.69						
	345	1,191	71,423	59.97						
	352	8	915	114.38						
	355				245,554	7,812,197	31.81			
								24,152	721,794	29.89

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Feb-11	155	9,596	515,658	53.74						
	224	121,398	7,485,752	61.66						
	345	936	60,466	64.60						
	355				330,931	7,867,230	23.77			
								7,413	203,037	27.39
Mar-11	155	11,032	566,877	51.38						
	224	167,830	9,063,793	54.01						
	345	858	57,603	67.14						
	355				502,988	11,600,765	23.06			
								6,029	189,946	31.51
Apr-11	155	15,572	606,291	38.93						
	224	164,230	8,726,760	53.14						
	345	579	39,945	68.99						
	355				618,224	14,188,453	22.95			
								3,256	109,433	33.61
May-11	35	42,777	792,209	18.52						
	155	16,324	648,972	39.76						
	224	173,679	9,311,462	53.61						
	345	368	28,018	76.14						
	355				797,049	15,842,119	19.88			
								5,182	(1,351)	(0.26)
Jun-11	33	41,459	1,464,428	35.32						
	34	31,095	1,098,347	35.32						
	35	107,501	2,191,176	20.38						
	155	15,915	636,843	40.02						
	224	174,716	9,303,831	53.25						
	345	363	26,742	73.67						
	352	4	598	149.50						
	355				646,648	12,969,331	20.06			
								8,705	393,106	45.16
Jul-11	33	50,289	1,756,982	34.94						
	34	37,717	1,317,745	34.94						
	35	111,478	3,815,718	34.23						
	155	10,055	528,715	52.58						
	224	164,093	8,878,007	54.10						
	345	429	29,265	68.22						
	355				875,740	24,180,464	27.61			
								639	71,427	111.78
Aug-11	33	51,800	1,856,449	35.84						
	34	38,850	1,392,337	35.84						
	35	110,100	3,291,117	29.89						
	155	11,040	576,490	52.22						
	224	180,211	9,631,375	53.44						
	345	362	25,789	71.24						
	355				793,003	19,359,907	24.41			
								1,264	132,285	104.66

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Sep-11	33	30,775	1,171,140	38.05						
	34	23,090	878,688	38.05						
	35	98,726	2,285,351	23.15						
	155	15,629	675,726	43.24						
	224	164,376	9,640,954	58.65						
	345	383	27,659	72.22						
	355				486,600	10,262,974	21.09			
								9,098	199,844	21.97
Oct-11	35	108,181	2,373,741	21.94						
	155	13,777	603,480	43.80						
	224	166,825	9,306,310	55.78						
	345	347	28,276	81.49						
	355				510,915	9,244,684	18.09			
								3,209	77,832	24.25
Nov-11	35	91,504	2,321,519	25.37						
	155	10,417	585,995	56.25						
	224	163,189	9,575,319	58.68						
	345	494	35,603	72.07						
	355				298,541	7,194,432	24.10			
								23,347	491,168	21.04
Dec-11	35	73,016	2,086,927	28.58						
	155	10,560	580,752	55.00						
	224	119,976	7,829,309	65.26						
	345	684	46,526	68.02						
	352	6	813	135.50						
	355				159,283	4,441,916	27.89			
								45,055	1,041,320	23.11
Jan-12	35	70,101	1,685,321	24.04						
	155	10,560	574,013	54.36						
	224	112,150	7,458,255	66.50						
	345	966	62,509	64.71						
	355				178,927	4,636,174	25.91			
								45,241	716,312	15.83
Feb-12	35	68,150	1,666,184	24.45						
	155	10,080	545,463	54.11						
	224	147,786	8,572,594	58.01						
	345	826	55,996	67.79						
	355				93,295	3,015,205	32.32			
								95,568	1,766,968	18.49
Mar-12	35	68,747	1,455,483	21.17						
	155	10,514	568,790	54.10						
	224	172,839	9,572,792	55.39						
	345	651	45,895	70.50						
	355				230,778	5,366,606	23.25			
								75,530	1,022,020	13.53

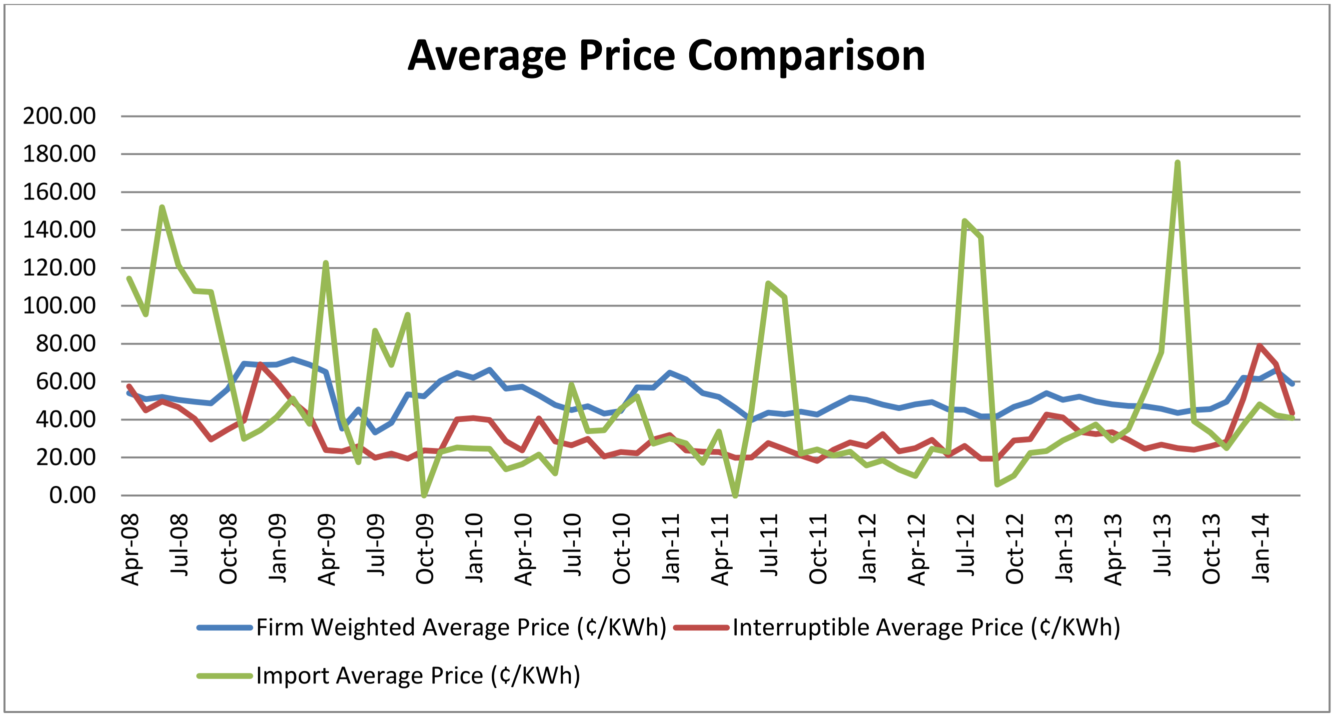
		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Apr-12	35	55,841	1,221,903	21.88						
	155	9,315	517,831	55.59						
	224	156,012	8,877,846	56.90						
	345	453	32,264	71.22						
	355				236,123	5,873,395	24.87			
								52,158	531,110	10.18
May-12	35	76,063	2,221,192	29.20						
	224	184,000	10,579,446	57.50						
	345	341	27,081	79.42						
	355				464,857	13,582,975	29.22			
								31,231	768,543	24.61
Jun-12	33	40,012	1,529,924	38.24						
	34	30,006	1,147,328	38.24						
	35	86,734	2,207,808	25.45						
	224	165,407	9,726,511	58.80						
	345	376	28,743	76.44						
	352	4	603	150.75						
	355				535,127	11,377,035	21.26			
								25,972	593,308	22.84
Jul-12	33	52,764	1,982,477	37.57						
	34	39,572	1,486,820	37.57						
	35	105,142	3,420,647	32.53						
	224	171,959	9,802,259	57.00						
	345	455	31,292	68.77						
	355				837,601	21,851,425	26.09			
								1,076	155,753	144.75
Aug-12	33	54,842	2,029,482	37.01						
	34	41,127	1,521,945	37.01						
	35	110,079	2,538,456	23.06						
	224	182,292	10,030,869	55.03						
	345	356	25,882	72.70						
	355				861,775	16,724,262	19.41			
								965	131,401	136.17
Sep-12	33	25,700	948,547	36.91						
	34	19,276	711,447	36.91						
	35	106,275	2,112,887	19.88						
	224	159,207	9,166,095	57.57						
	345	373	28,105	75.35						
	355				721,490	13,980,585	19.38			
								1,054	5,994	5.69
Oct-12	35	83,081	2,206,126	26.55						
	224	182,081	10,148,590	55.74						
	345	440	38,755	88.08						
	355				344,967	10,007,508	29.01			
								14,646	152,582	10.42

		FIRM			INTERRUPTIBLE			IMPORT		
Month	**NEB Permit No.**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**	**MWh**	**Revenue (CAN$)**	**¢/KWh**
Nov-12	35	67,050	1,927,256	28.74						
	224	159,745	9,274,114	58.06						
	345	576	39,686	68.90						
	355				225,082	6,652,755	29.56			
								37,599	843,016	22.42
Dec-12	35	61,875	2,123,564	34.32						
	224	129,155	8,179,452	63.33						
	345	729	51,157	70.17						
	352	11	1,300	118.18						
	355				84,723	3,604,653	42.55			
								132,654	3,112,020	23.46
Jan-13	35	66,150	2,181,518	32.98						
	224	169,751	9,694,967	57.11						
	345	1,172	76,021	64.86						
	355				86,194	3,545,803	41.14			
								121,703	3,513,341	28.87
Feb-13	35	66,150	2,076,848	31.40						
	224	155,269	9,453,748	60.89						
	345	1,157	75,852	65.56						
	355				153,549	5,156,723	33.58			
								55,965	1,849,321	33.04
Mar-13	35	86,700	2,820,083	32.53						
	224	168,000	9,789,201	58.27						
	345	771	55,660	72.19						
	355				352,598	11,406,112	32.35			
								10,005	374,131	37.39
Apr-13	35	103,820	3,357,126	32.34						
	224	171,343	9,831,099	57.38						
	345	672	47,102	70.09						
	355				354,939	11,822,526	33.31			
								17,123	495,957	28.96
May-13	35	111,440	3,163,407	28.39						
	224	183,788	10,749,558	58.49						
	345	341	27,081	79.42						
	355				464,857	13,582,975	29.22			
								2,505	87,170	34.80
Jun-13	33	32,938	1,322,307	40.15						
	34	24,702	991,670	40.15						
	35	107,636	2,945,708	27.37						
	224	158,794	9,953,623	62.68						
	345	414	31,011	74.91						
	352	9	1,175	130.56						
	355				852,421	20,994,789	24.63			
								1,686	91,559	54.31

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Jul-13	33	60,366	2,371,542	39.29						
	34	45,275	1,778,676	39.29						
	35	111,334	3,463,052	31.11						
	224	183,917	10,700,422	58.18						
	345	434	32,283	74.38						
	355				955,531	25,629,741	26.82			
								2,474	186,819	75.51
Aug-13	33	54,620	2,201,290	40.30						
	34	41,003	1,652,499	40.30						
	35	111,495	3,339,358	29.95						
	224	174,750	10,617,822	60.76						
	345	376	28,247	75.13						
	379	80,023	2,216,928	27.70						
	355				902,359	22,540,778	24.98			
								2,469	433,454	175.56
Sep-13	33	20,789	816,559	39.28						
	34	15,585	612,154	39.28						
	35	80,035	2,134,183	26.67						
	224	130,146	8,644,370	66.42						
	345	376	30,511	81.15						
	379	57,526	1,435,549	24.95						
	355				651,033	15,711,517	24.13			
								2,679	104,702	39.08
Oct-13	33									
	34									
	35	106,105	3,045,103	28.70						
	224	183,718	10,840,420	59.01						
	345	415	32,481	78.27						
	379	53,097	1,701,338	32.04						
	355				752,750	19,523,112	25.94			
								738	24,482	33.17
Nov-13	33									
	34									
	35	83,290	2,287,598	27.47						
	224	153,190	9,815,402	64.07						
	345	696	49,473	71.08						
	379	25,132	796,919	31.71						
	355				310,592	8,792,251	28.31			
								21,725	539,951	24.85

		FIRM			INTERRUPTIBLE			IMPORT		
Month	NEB Permit No.	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh	MWh	Revenue (CAN$)	¢/KWh
Dec-13	33									
	34									
	35	52,414	2,191,693	41.82						
	224	136,243	9,517,567	69.86						
	345	893	64,070	71.75						
	352	16	1,926	120.38						
	379									
	355				89,619	4,554,245	50.82			
								73,075	2,707,912	37.06
Jan-14	33									
	34									
	35	20,400	883,602	43.31						
	224	179,829	11,397,041	63.38						
	345	1,339	88,923	66.41						
	379									
	355				90,736	7,153,983	78.84			
								176,865	8,488,522	47.99
Feb-14	33									
	34									
	35	4,500	250,082	55.57						
	224	158,243	10,464,053	66.13						
	345									
	379									
	355				105,955	7,341,754	69.29			
								143,638	6,065,761	42.23
Mar-14	33									
	34									
	35	44,100	1,594,046	36.15						
	224	166,631	10,791,002	64.76						
	345									
	379									
	355				269,824	11,669,319	43.25			
								70,686	2,883,423	40.79

NOTE: Data for March 2014 is Preliminary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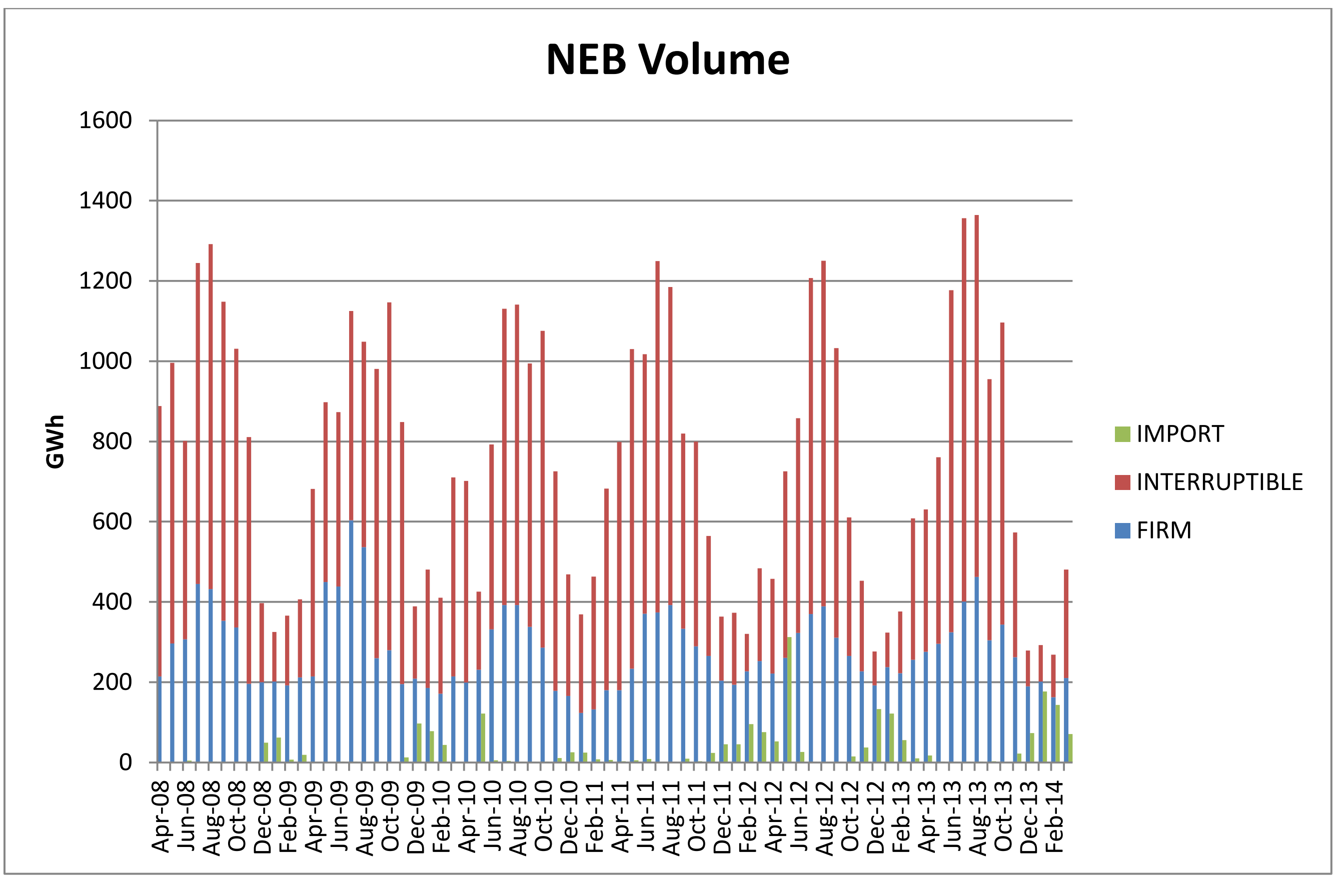
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Apr-08
Jul-08
Oct-08
Jan-09
Apr-09
Jul-09
Oct-09
Jan-10
Apr-10
Jul-10
Oct-10
Jan-11
Apr-11
Jul-11
Oct-11
Jan-12
Apr-12
Jul-12
Oct-12
Jan-13
Apr-13
Jul-13
Oct-13
Jan-14
Firm Weighted Average Price (¢/KWh)
Interruptible Average Price (¢/KWh)
Import Average Price (¢/KWh)


NEB Volume
GWh
1600
1400
1200
1000
800
600
400
200
0
Apr-08
Jun-08
Aug-08
Oct-08
Dec-08
Feb-09
Apr-09
Jun-09
Aug-09
Oct-09
Dec-09
Feb-10
Apr-10
Jun-10
Aug-10
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Apr-12
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Oct-13
Dec-13
Feb-14
IMPORT
INTERRUPTIBLE
FIRM

PUB/MH I-27

Reference: NFAT PUB/MH I-008 (pp 1 to 30), 2014 GRA Tables (d2), (d3) & (d4)

a) Please refile this IR updated to include 2012/13 (complete) and 2013/14.

ANSWER:

TOTAL SALES									
	DEPENDABLE SALES			**OPPORTUNITY SALES**			**SYSTEM MERCHANT SALES**		
	GWh	**CAD $M**	**AvgPrice**	**GWh**	**CAD $M**	**AvgPrice**	**GWh**	**CAD $M**	**AvgPrice**
2000/01	6,352	258	40.64	5,801	217	37.39	0	0	0
2001/02	6,277	322	51.65	6,022	281	46.63	0	0	0
2002/03	6,544	339	53.37	3,191	137	42.97	0	0	0
2003/04	6,231	295	48.46	735	52	48.46	11	0.5	44.43
2004/05	5,633	290	51.44	4,798	239	51.44	315	11	33.32
2005/06	4,044	240	59.25	10,303	510	47.73	919	63	60.07
2006/07	3,654	218	59.67	6,250	295	46.53	1,206	60	43.38
2007/08	3,921	209	53.22	7,099	328	44.42	1,262	72	49.17
2008/09	4,087	233	57.12	6,039	287	43.64	1,598	86	48.08
2009/10	3,263	186	56.99	7,597	184	22.98	775	26	28.29
2010/11	3,377	172	51.09	6,967	181	24.77	712	27	36.93
2011/12	3,742	175	46.79	6,502	152	22.18	436	17	31.10
2012/13	3,636	177	48.69	5,451	146	25.18	150	9	34.18
2013/14	3,479	182	52.22	7,058	203	28.92	331	34	63.32

Dependable sales include both fixed and market priced energy sold under dependable sale contracts. Energy sold under these contracts can be both dependable and surplus energy.

TOTAL U.S. SALES									
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES			U.S. SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2000/01	4,895	199	40.69	4,511	167	36.95	0	0	0
2001/02	4,767	263	55.15	5,083	247	48.66	0	0	0
2002/03	4,947	277	56.09	2,713	115	42.30	0	0	0
2003/04	5,245	259	49.45	507	35	69.42	0	0	0
2004/05	5,633	290	51.44	3,218	171	54.48	109	1	10.64
2005/06	4,044	240	59.25	8,879	401	45.12	0	0	0
2006/07	3,654	218	59.67	5,877	270	46.24	0	0	0
2007/08	3,921	209	53.22	6,618	289	44.19	0	0	0
2008/09	4,087	233	57.12	5,622	237	43.24	0	0	0
2009/10	3,263	186	56.99	7,224	160	22.28	33	2	0
2010/11	3,377	172	51.09	6,062	146	24.44	5	0.3	37.82
2011/12	3,742	175	46.79	5,616	117	21.13	80	3	35.21
2012/13	3,636	177	48.69	4,690	113	23.62	63	2	29.92
2013/14	3,479	182	52.22	6,336	182	27.70	185	7	37.17

OPPORTUNITY EXPORTS						
	On Peak GWh	Off Peak GWh	On Peak Avg Price (CAD$)	Off Peak Avg Price (CAD$)	On Peak Revenues (CAD $M)	Off Peak Revenues (CAD $M)
2005/06	3,142	7,161	72.73	36.75	245	265
2006/07	1,972	4,278	66.26	37.44	135	160
2007/08	2,212	4,887	66.19	32.97	162	166
2008/09	1,802	4,237	71.78	29.37	153	134
2009/10	2,497	5,100	31.14	18.74	84	100
2010/11	2,268	4,699	31.90	21.23	76	105
2011/12	1,952	4,550	28.76	22.51	59	93
2012/13	2,165	3,286	29.87	22.02	69	77
2013/14	2,492	4,566	36.95	24.46	82	121

	EXPORT REVENUES																	
	2008/09			2009/10			2010/11			2011/12			2012/13			2013/14		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity																		
Bilateral	1305	101	71.37	2628	60	24.08	1851	52	28.44	1923	50	26.02	1700	54	31.66	1471	53	36.07
Market																		
Day Ahead	4040	122	30.33	3111	59	19.09	3233	69	21.39	2720	52	18.68	2547	53	22.02	4251	109	27.53
Real Time	690	60	50.88	1858	71	27.33	1883	60	26.83	1859	50	23.24	1203	36	25.96	1336	32	30.94
Merchant	1598	86	48.08	775	26	28.29	712	27	36.93	436	17	31.10	150	9	34.18	331	33	63.32

	Fuel & Power Purchased											
	2008/09		2009/10		2010/11		2011/12		2012/13		2013/14	
	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)	GWh	$M (Cdn)
System Merchant	1598	80	775	25	712	24	436	14	150	6	331	19
Power Purchases	981	57	1320	33	1154	34	1634	79	1584	71	1824	98
Transmission Charges		21		33		36		39		44		45
Fuel Purchases		18		13		12		14		12		14

PUB/MH I-27

Reference: NFAT PUB/MH I-008 (pp 1 to 30), 2014 GRA Tables (d2), (d3) & (d4)

b) Please provide monthly data for 2012/13 and 2013/14.

ANSWER:

Please see the tables below.

Table (d.2) MISO Sales.

	MWh	$Cdn	Avg Price $/MWh
Apr-2012	161,937	3,283,861	22.11
May-2012	331,545	9,121,261	27.57
Jun-2012	428,203	8,149,828	18.60
Jul-2012	670,787	16,590,278	24.42
Aug-2012	697,404	12,403,781	17.78
Sep-2012	534,243	9,429,893	17.65
Oct-2012	226,493	5,860,929	26.88
Nov-2012	115,666	2,632,902	23.12
Dec-2012	-15,219	-568,911	35.03
Jan-2013	39,098	1,207,975	27.40
Feb-2013	109,132	3,018,964	27.64
Mar-2013	276,273	8,178,435	29.47
Apr-2013	254,607	7,758,784	30.54
May-2013	669,266	17,046,682	25.29
Jun-2013	770,944	17,736,990	23.29
Jul-2013	797,967	20,086,498	25.15
Aug-2013	814,051	19,022,798	23.49
Sep-2013	618,380	14,371,211	23.41
Oct-2013	722,130	17,438,224	24.14
Nov-2013	272,745	7,334,825	26.70
Dec-2013	6,632	47,628	18.22
Jan-2014	56,914	4,613,696	81.00
Feb-2014	78,129	5,286,446	67.72
Mar-2014	236,307	9,705,090	40.98

Table (d.3) Canadian extra-provincial sales.

Month	MWh	$Cdn	Avg Price $/MWh
Apr-2012	64,111	2,229,185	33.11
May-2012	78,869	3,130,376	29.01
Jun-2012	30,827	1,260,015	36.35
Jul-2012	30,887	1,341,494	37.74
Aug-2012	77,936	1,964,620	31.70
Sep-2012	66,716	2,187,905	14.84
Oct-2012	59,814	2,539,985	39.49
Nov-2012	80,835	3,300,471	39.23
Dec-2012	74,670	3,166,890	41.25
Jan-2013	73,878	3,647,506	44.56
Feb-2013	53,526	2,629,759	41.87
Mar-2013	67,863	2,907,552	42.96
Apr-2013	56,602	2,346,493	36.45
May-2013	35,423	1,149,651	30.33
Jun-2013	21,617	929,329	25.24
Jul-2013	29,760	916,771	23.47
Aug-2013	100,600	3,298,657	31.88
Sep-2013	76,481	2,904,089	36.34
Oct-2013	75,112	2,672,767	33.90
Nov-2013	82,006	2,367,753	27.47
Dec-2013	48,233	2,365,698	46.65
Jan-2014	49,446	2,255,749	47.12
Feb-2014	70,476	4,579,106	62.51
Mar-2014	75,675	6,127,424	60.93

Table (d.4). Aggregate purchases

Month	MWh	$Cdn	Avg Price $/MWh
Apr-2012	153,924	6,401,825	41.59
May-2012	113,225	3,036,232	26.82
Jun-2012	111,169	4,691,735	42.20
Jul-2012	65,946	3,905,722	59.23
Aug-2012	80,756	4,699,546	58.19
Sep-2012	113,842	5,462,288	47.98
Oct-2012	145,290	7,395,462	50.90
Nov-2012	130,948	6,405,906	48.92
Dec-2012	202,694	7,912,772	39.04
Jan-2013	225,023	10,446,957	46.43
Feb-2013	127,333	6,839,664	53.71
Mar-2013	101,192	5,835,134	57.66
Apr-2013	128,406	7,124,768	55.49
May-2013	107,766	6,672,022	61.91
Jun-2013	90,514	4,930,776	54.48
Jul-2013	76,503	4,186,686	54.73
Aug-2013	61,884	3,628,264	58.63
Sep-2013	125,554	5,892,456	46.93
Oct-2013	129,232	6,182,279	47.84
Nov-2013	162,980	8,344,787	51.20
Dec-2013	192,362	9,735,150	50.61
Jan-2014	311,491	16,873,423	54.17
Feb-2014	261,815	13,971,264	53.36
Mar-2014	175,245	9,635,614	54.98

Notes:

1. Includes Day Ahead and Real Time Purchases and wind generation purchases.
2. Aggregated information is provided to comply with confidentiality provisions of power purchase agreements.
3. Updated Dec/13 to Mar/14 to include Purchases from Diversity Contract

PUB/MH I-27

Reference: NFAT PUB/MH I-008 (pp 1 to 30), 2014 GRA Tables (d2), (d3) & (d4)

c) Please provide a separate tabulation of monthly wind energy purchases (aggregated), imports and thermal generation for 2012/13 and 2013/14.

ANSWER:

Please see the table below.

	Aggregated Imports		Thermal
Month	MWh	$Cdn	Generation MWh
Apr-2012	153,924	6,401,825	4,005
May-2012	113,225	3,036,232	0
Jun-2012	111,169	4,691,735	1,110
Jul-2012	65,946	3,905,722	873
Aug-2012	80,756	4,699,546	1,905
Sep-2012	113,842	5,462,288	24,281
Oct-2012	145,290	7,395,462	24,513
Nov-2012	130,948	6,405,906	12,493
Dec-2012	202,694	7,912,772	2,935
Jan-2013	225,023	10,446,957	8,234
Feb-2013	127,333	6,839,664	2,275
Mar-2013	101,192	5,835,134	590
Apr-2013	128,406	7,124,768	7,549
May-2013	107,766	6,672,022	16,451
Jun-2013	90,514	4,930,776	-
Jul-2013	76,503	4,186,686	9,868
Aug-2013	61,884	3,628,264	9,335
Sep-2013	125,554	5,892,456	829
Oct-2013	129,232	6,182,279	22,117
Nov-2013	162,980	8,344,787	2,803
Dec-2013	192,362	9,735,150	10,810
Jan-2014	311,491	16,873,423	21,747
Feb-2014	261,815	13,971,264	14,040
Mar-2014	175,245	9,635,614	15,479

NOTE: Aggregated imports includes Wind energy, it is provided this way to comply with confidentiality provisions of power purchase agreements.

PUB/MH I-27

Reference: NFAT PUB/MH I-008 (pp 1 to 30), 2014 GRA Tables (d2), (d3) & (d4)

d) Please explain the need for a high level of purchases (other than wind) in the last 4 months when Lake Winnipeg levels and overall energy sources are well above average.

ANSWER:

Outflows from Lake Winnipeg were at the maximum possible over the past four months. However, due to winter ice restrictions these outflows were not sufficient to avoid the need to purchase additional energy necessary to meet load requirements. Manitoba domestic demand was unusually high as a result of the record cold winter. Purchasing the additional energy needed was much more economic than operating Manitoba Hydro's gas fired generation.

<u>PUB/MH I-28</u>

Reference: IFF 13 p.32

a) Explain the $408 M and $383 M extraprovincial revenue forecast for 2013/14 and 20414/15 respectively, in light of favourable water conditions and market prices, as well as a higher exchange rate.

<u>ANSWER</u>:

Please see Manitoba Hydro's response to PUB/MH I-8(a).

PUB/MH I-28

Reference: IFF 13 p.32

b) Confirm that Manitoba Hydro's 2013/14 General Consumers revenue could be significantly higher than indicated in IFF 13 given the cold winter impact on electricity consumption. Please quantify this effect.

ANSWER:

The impact of the colder than normal weather will be reflected in Manitoba Hydro's financial results for 2013/14. As noted in the response to PUB/MH I-6(a), Manitoba Hydro's financial results for the fourth quarter of 2013/14 are not yet available, and pursuant to Sections 7 and 8 of *The Crown Corporations Public Review and Accountability Act* and to Section 46 of *The Manitoba Hydro Act*, Manitoba Hydro cannot publically release its financial results until its Annual Report has been tabled with the Legislative Assembly.

PUB/MH I-29

Reference: IFF 13 Section 7.0

a) Provide a historical perspective on MH's O&M costs for the last 10 years by tabulating the annual IFF forecasts and the annual actual results.

ANSWER:

The following table provides a historical summary of Manitoba Hydro's O&M costs from 2005 to 2013. Fiscal 2014 actual results are not available at this time.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS
(000's)

Year	Actual	Forecast
2005	$ 298,613	$ 296,926
2006	310,658	311,408
2007	323,465	327,600
2008	322,696	340,200
2009	364,287	348,999
2010	377,551	371,504
2011	396,946	397,638
2012	403,304	401,900
2013	462,947	455,309
2014		484,505

PUB/MH I-29

Reference: IFF 13 Section 7.0

b) Confirm that from 2008 to 2014, MH's O&M costs increased from $380 M± to $560 M±; a $180 M increase over 6 years or $30 M/year.

ANSWER:

As illustrated in PUB/MH I-29(a) Manitoba Hydro's actual OM&A costs increased from $323 million in 2008 to $463 million in 2013, an increase of $140 million (fiscal 2014 actual results are not available at this time). As outlined in the response to CAC/MH 1-3, approximately $80 million of the increase is due to accounting changes, and as such the OM&A expense net of accounting changes in 2012/13 is $383 million.

PUB/MH I-29

Reference: IFF 13 Section 7.0

c) Provide the actual annual % increase in O&M from 2008 to 2014.

ANSWER:

The following table highlights the actual annual % increase in OM&A from 2008 to 2013. Fiscal 2014 actual results are not available at this time.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS
(000's)

Year	Actual	% Increase
2008	$ 322,696	
2009	364,287	12.9%
2010	377,551	3.6%
2011	396,946	5.1%
2012	403,304	1.6%
2013	462,947	14.8%

The most significant increases occurred in 2009 and 2013.

As discussed in the 2010/11 GRA, the increase in 2009 was primarily due to the restoration of staffing levels given the high vacancy rates experienced in the 2007/08 period as well as increases in trainee levels to address staff shortages and anticipated attrition levels. In addition, CICA accounting standard changes related to Intangible Assets as well as eliminating the capitalization of interest and facilities overhead on stores withdrawals contributed to the increase.

The increase in 2013 was primarily due to accounting changes including adjustments to Manitoba Hydro's overhead capitalization practices recognizing industry trends to move away from full cost accounting, higher pension and other benefit costs primarily as a result of the lower discount rate and the reclassification of certain operating expense recoveries to Other Revenue.

PUB/MH I-29

Reference: IFF 13 Section 7.0

d) Confirm that IFF 12 looked for an O&M cost increase of $400 M over 20 years ($550 M to $950 M) and that IFF 13 looks at a lower increase of $340 M ($560 M to $900 M) over 20 years; a 10% reduction over 20 years?

ANSWER:

The reductions in OM&A from IFF12 to IFF13 represent 17% on consolidated operations and 17% on electric operations over 20 years. The reduction in O&M costs over the 20 year period is primarily due to the implementation of additional cost containment measures as discussed in PUB/MH 1-30(d).

IFF12 O&M cost increase over 20 years was $406 M ($529 M to $935 M) on consolidated operations. MH12 O&M cost increase over 20 years was $368 M ($455 M to $823 M) on electric operations.

IFF13 O&M cost increase over 20 years was $335 M ($556 M to $891 M) on consolidated operations. MH13 O&M cost increase over 20 years was $309 M ($485 M to $794 M) on electric operations.

PUB/MH I-30

Preamble: **The Corporation states that "by implementing these further cost containment initiatives, Manitoba Hydro has maintained projected annual rate increases for each year of MH13-1 at the same level as those projected in MH12, namely 3.95%".**

MH13-1 reflects net losses in 2018 through 2022 totalling $245 million

a) Please explain what factors are causing the material losses in those years.

ANSWER:

A significant factor resulting in losses in MH13 between 2018 and 2022 is the fact that there are two major capital projects, namely Bipole III and Keeyask Generating Station, which are projected to fully come into service in 2018 and 2021. The nature of Manitoba Hydro's Cost of Service rate-setting methodology is to smooth the rate impacts to Manitoba customers of such investments coming into service, while making progress towards attaining Manitoba Hydro's financial targets at the end of the forecast period. The projected rate increases in the early years of MH13 do not fully cover the carrying costs of these facilities, and as such losses result until such time as the associated extraprovincial revenues are sufficient to result in a positive net income.

Another factor in MH13 is the increased capital expenditures forecast over this period which is contributing to an increased debt requirement leading to higher finance expense and greater losses.

PUB/MH I-30

Preamble: **The Corporation states that "by implementing these further cost containment initiatives, Manitoba Hydro has maintained projected annual rate increases for each year of MH13-1 at the same level as those projected in MH12, namely 3.95%".**

MH13-1 reflects net losses in 2018 through 2022 totalling $245 million

b) Please provide a comparison with the forecast losses in MH12-1 and indicate why the number of years and magnitude of the losses has grown.

ANSWER:

The attached schedule indicates the change in Net Income between MH12 and MH13 for the period 2018 to 2022. Although there are changes in all the line items in the income statement, the primary change can be summarized by an increase in finance expense due to higher capital expenditure requirements in MH13.

CHANGES in MH13 VS MH12

	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total Change
Net Income										
MH12	60	50	73	57	19	(68)	(9)	(7)	52	228
MH13	116	55	12	19	(12)	(67)	(31)	(75)	(60)	(43)
Net Change in MH 13 from MH12	55	5	(60)	(39)	(31)	1	(22)	(68)	(112)	(271)

PUB/MH I-30

Preamble: **The Corporation states that "by implementing these further cost containment initiatives, Manitoba Hydro has maintained projected annual rate increases for each year of MH13-1 at the same level as those projected in MH12, namely 3.95%".**

MH13-1 reflects net losses in 2018 through 2022 totalling $245 million

c) **Please provide an updated MH13-1, and key financial ratios for electric operations (Page iii) indicating the equal annual rate increases required ensuring no losses in 2018 through 2022.**

ANSWER:

Please see the MH13 scenario below for the requested information, which projects even annual rate increases of 4.80% to avoid losses in 2018 to 2022.

In practice, Manitoba Hydro would smooth the rates required from 2021 through 2033 to attain a 75:25 debt equity ratio in 2033. This alternate scenario is also provided below, which projects 3.59% rate increases from 2021 to 2033.

MH13 with 4.8% Increases

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2014	-	$116	$2 584	76:24	1.20	1.03
2015	3.95%	55	2 638	78:22	1.09	0.86
2016	4.80%	25	2 605	82:18	1.03	0.80
2017	4.80%	46	2 651	84:16	1.05	0.88
2018	4.80%	33	2 684	85:15	1.03	1.22
2019	4.80%	(0)	2 684	86:14	1.00	1.15
2020	4.80%	58	2 741	87:13	1.05	1.31
2021	4.80%	41	2 783	87:13	1.03	1.40
2022	4.80%	86	2 869	87:13	1.06	1.63
2023	4.80%	191	3 060	87:13	1.14	1.90
2024	4.80%	294	3 354	87:13	1.19	2.13
2025	4.80%	406	3 760	86:14	1.25	2.37
2026	4.80%	494	4 253	85:15	1.29	2.55
2027	4.80%	668	4 921	84:16	1.39	2.95
2028	4.80%	729	5 650	82:18	1.42	3.22
2029	4.80%	785	6 435	79:21	1.46	3.43
2030	4.80%	1 007	7 442	76:24	1.61	3.82
2031	4.80%	1 208	8 651	72:28	1.75	4.23
2032	4.80%	1 502	10 152	68:32	2.00	4.79
2033	4.80%	1 803	11 955	62:38	2.27	5.33

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES										
General Consumers										
at approved rates	1 396	1 408	1 423	1 438	1 452	1 471	1 490	1 508	1 528	1 548
additional*	0	56	127	204	285	373	468	569	677	793
BPIII Reserve Account	(18)	(21)	(22)	(24)	(13)	0	0	0	0	0
Extraprovincial	408	383	362	390	441	448	484	760	862	880
Other	13	13	13	14	14	14	14	15	15	15
	1 799	1 838	1 903	2 021	2 180	2 306	2 456	2 852	3 082	3 236
EXPENSES										
Operating and Administrative	485	494	542	548	567	574	586	612	620	633
Finance Expense	437	499	513	566	654	777	827	1 087	1 169	1 158
Depreciation and Amortization	415	440	437	448	485	499	520	600	667	675
Water Rentals and Assessments	125	123	111	111	112	111	113	124	127	127
Fuel and Power Purchased	144	142	174	189	203	214	217	250	265	273
Capital and Other Taxes	93	101	109	121	131	134	135	137	140	168
Corporate Allocation	9	9	9	9	9	9	9	9	9	9
	1 707	1 807	1 895	1 991	2 160	2 316	2 407	2 818	2 995	3 043
Non-controlling Interest	24	24	18	16	13	10	8	7	0	(2)
Net Income	116	55	25	46	33	(0)	58	41	86	191
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%
Cumulative Percent Increase	0.00%	3.95%	8.94%	14.17%	19.64%	25.38%	31.40%	37.71%	44.31%	51.24%
Financial Ratios										
Equity	24%	22%	18%	16%	15%	14%	13%	13%	13%	13%
Interest Coverage	1.20	1.09	1.03	1.05	1.03	1.00	1.05	1.03	1.06	1.14
Capital Coverage	1.03	0.86	0.80	0.88	1.22	1.15	1.31	1.40	1.63	1.90

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REVENUES										
General Consumers										
at approved rates	1 568	1 588	1 609	1 629	1 649	1 672	1 694	1 715	1 737	1 758
additional*	917	1 050	1 192	1 343	1 504	1 677	1 863	2 059	2 268	2 491
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360
Other	16	16	16	16	17	17	17	18	18	19
	3 382	3 521	3 612	3 965	4 407	4 710	4 915	5 134	5 382	5 628
EXPENSES										
Operating and Administrative	646	660	673	705	720	735	748	762	778	794
Finance Expense	1 159	1 143	1 118	1 215	1 488	1 635	1 581	1 568	1 481	1 397
Depreciation and Amortization	679	684	694	741	829	886	895	911	918	921
Water Rentals and Assessments	127	127	127	135	148	151	151	152	153	153
Fuel and Power Purchased	284	300	298	283	271	291	301	299	311	321
Capital and Other Taxes	178	186	194	200	204	206	208	208	212	211
Corporate Allocation	9	9	9	9	9	9	9	7	6	6
	3 081	3 107	3 111	3 287	3 667	3 913	3 892	3 908	3 860	3 803
Non-controlling Interest	(6)	(8)	(8)	(10)	(11)	(13)	(16)	(18)	(20)	(23)
Net Income	294	406	494	668	729	785	1 007	1 208	1 502	1 803
* Additional General Consumers Revenue										
Percent Increase	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%	4.80%
Cumulative Percent Increase	58.50%	66.10%	74.07%	82.42%	91.18%	100.35%	109.97%	120.04%	130.60%	141.66%
Financial Ratios										
Equity	13%	14%	15%	16%	18%	21%	24%	28%	32%	38%
Interest Coverage	1.19	1.25	1.29	1.39	1.42	1.46	1.61	1.75	2.00	2.27
Capital Coverage	2.13	2.37	2.55	2.95	3.22	3.43	3.82	4.23	4.79	5.33

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	16 237	17 381	18 305	19 095	22 681	23 407	26 910	30 963	31 516	31 998
Accumulated Depreciation	(5 434)	(5 814)	(6 168)	(6 564)	(7 003)	(7 508)	(8 019)	(8 609)	(9 236)	(9 875)
Net Plant in Service	10 803	11 568	12 137	12 531	15 677	15 900	18 891	22 355	22 280	22 124
Construction in Progress	2 425	3 296	4 743	6 454	5 200	6 525	4 779	1 967	3 154	4 978
Current and Other Assets	1 649	1 669	1 534	1 742	2 172	2 054	2 373	2 440	2 057	2 106
Goodwill and Intangible Assets	188	172	154	139	127	118	107	96	87	81
Regulated Assets	220	213	203	190	180	169	159	149	142	134
	15 285	16 918	18 770	21 056	23 357	24 766	26 309	27 007	27 720	29 423
LIABILITIES AND EQUITY										
Long-Term Debt	10 464	11 904	14 123	16 197	17 226	19 926	21 098	21 831	22 607	24 303
Current and Other Liabilities	1 653	1 760	1 713	1 829	3 004	1 696	2 052	2 022	1 892	1 713
Contributions in Aid of Construction	362	372	382	391	401	413	425	437	449	462
BPIII Reserve Account	18	40	62	86	99	66	33	-	-	-
Retained Earnings	2 584	2 638	2 605	2 651	2 684	2 684	2 741	2 783	2 869	3 060
Accumulated Other Comprehensive Income	204	204	(115)	(98)	(57)	(19)	(41)	(66)	(97)	(114)
	15 285	16 918	18 770	21 056	23 357	24 766	26 309	27 007	27 720	29 423

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	32 572	33 228	33 848	40 307	44 992	46 716	47 170	49 034	49 786	50 231
Accumulated Depreciation	(10 520)	(11 173)	(11 836)	(12 546)	(13 347)	(14 206)	(15 074)	(15 960)	(16 853)	(17 749)
Net Plant in Service	22 052	22 055	22 012	27 760	31 645	32 510	32 095	33 074	32 933	32 482
Construction in Progress	6 748	8 235	9 645	5 009	1 707	1 065	1 525	472	382	553
Current and Other Assets	2 357	2 567	2 408	2 672	2 954	3 681	4 415	5 013	6 748	8 814
Goodwill and Intangible Assets	77	72	68	63	58	54	49	45	40	36
Regulated Assets	129	123	119	112	107	103	100	99	98	98
	31 362	33 052	34 251	35 617	36 472	37 414	38 184	38 702	40 201	41 982
LIABILITIES AND EQUITY										
Long-Term Debt	26 297	27 051	28 254	28 857	28 999	28 981	28 253	28 243	28 247	28 060
Current and Other Liabilities	1 351	1 870	1 362	1 448	1 422	1 587	2 067	1 375	1 361	1 521
Contributions in Aid of Construction	475	488	501	514	527	540	553	567	581	596
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3 354	3 760	4 253	4 921	5 650	6 435	7 442	8 651	10 152	11 955
Accumulated Other Comprehensive Income	(114)	(117)	(120)	(123)	(126)	(129)	(132)	(135)	(141)	(150)
	31 362	33 052	34 251	35 617	36 472	37 414	38 184	38 702	40 201	41 982

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 818	1 859	1 925	2 045	2 193	2 306	2 456	2 852	3 082	3 236
Cash Paid to Suppliers and Employees	(809)	(817)	(902)	(932)	(971)	(988)	(1 004)	(1 073)	(1 099)	(1 147)
Interest Paid	(491)	(506)	(534)	(581)	(687)	(809)	(860)	(1 138)	(1 224)	(1 181)
Interest Received	26	13	16	23	34	37	35	32	29	16
	544	549	506	555	569	546	627	672	787	924
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 316	1 740	2 570	2 390	2 390	3 000	1 800	1 390	1 190	1 970
Sinking Fund Withdrawals	410	103	16	-	12	412	185	268	670	155
Retirement of Long-Term Debt	(610)	(217)	(312)	(336)	(330)	(1 442)	(305)	(633)	(673)	(431)
Other	(116)	(11)	(12)	(12)	(11)	(22)	(11)	(57)	15	(6)
	1 000	1 616	2 261	2 043	2 061	1 948	1 669	969	1 202	1 688
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 578)	(2 039)	(2 439)	(2 511)	(2 413)	(2 074)	(2 061)	(1 352)	(1 735)	(2 300)
Sinking Fund Payment	(194)	(114)	(184)	(159)	(224)	(217)	(223)	(245)	(338)	(240)
Other	(14)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(1 786)	(2 175)	(2 644)	(2 691)	(2 658)	(2 325)	(2 314)	(1 627)	(2 103)	(2 569)
Net Increase (Decrease) in Cash	(243)	(10)	123	(93)	(29)	168	(17)	14	(114)	42
Cash at Beginning of Year	25	(218)	(227)	(104)	(197)	(226)	(58)	(75)	(61)	(175)
Cash at End of Year	(218)	(227)	(104)	(197)	(226)	(58)	(75)	(61)	(175)	(133)

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 382	3 521	3 612	3 965	4 407	4 710	4 915	5 134	5 382	5 628
Cash Paid to Suppliers and Employees	(1 177)	(1 211)	(1 227)	(1 256)	(1 273)	(1 311)	(1 332)	(1 341)	(1 370)	(1 390)
Interest Paid	(1 171)	(1 169)	(1 146)	(1 264)	(1 554)	(1 720)	(1 680)	(1 682)	(1 569)	(1 503)
Interest Received	17	26	31	41	58	75	83	95	75	93
	1 050	1 168	1 270	1 486	1 638	1 755	1 987	2 206	2 518	2 827
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 990	1 180	1 190	580	190	180	(40)	(10)	(20)	(50)
Sinking Fund Withdrawals	24	-	420	-	-	60	250	700	13	30
Retirement of Long-Term Debt	(290)	-	(450)	-	-	(60)	(220)	(700)	(13)	-
Other	1	1	0	1	1	1	2	3	(16)	(16)
	1 726	1 181	1 161	581	191	181	(8)	(7)	(36)	(36)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 338)	(2 135)	(2 021)	(1 812)	(1 372)	(1 070)	(901)	(798)	(650)	(603)
Sinking Fund Payment	(258)	(284)	(308)	(311)	(330)	(344)	(356)	(358)	(337)	(349)
Other	(30)	(30)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)
	(2 626)	(2 450)	(2 355)	(2 148)	(1 728)	(1 440)	(1 284)	(1 183)	(1 014)	(980)
Net Increase (Decrease) in Cash	149	(101)	75	(81)	101	496	695	1 016	1 468	1 811
Cash at Beginning of Year	(133)	16	(84)	(9)	(90)	10	506	1 201	2 218	3 686
Cash at End of Year	16	(84)	(9)	(90)	10	506	1 201	2 218	3 686	5 497

MH13 with 4.8% through 2020, with smoothed rate increases to achieve 25% Equity in 2033

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2014	-	$116	$2 584	76:24	1.20	1.03
2015	3.95%	55	2 638	78:22	1.09	0.86
2016	4.80%	25	2 605	82:18	1.03	0.80
2017	4.80%	46	2 651	84:16	1.05	0.88
2018	4.80%	33	2 684	85:15	1.03	1.22
2019	4.80%	0	2 684	86:14	1.00	1.15
2020	4.80%	58	2 741	87:13	1.05	1.31
2021	3.59%	17	2 759	87:13	1.01	1.35
2022	3.59%	33	2 792	88:12	1.02	1.52
2023	3.59%	103	2 894	88:12	1.07	1.72
2024	3.59%	167	3 061	88:12	1.11	1.87
2025	3.59%	233	3 294	88:12	1.14	2.03
2026	3.59%	268	3 562	87:13	1.16	2.10
2027	3.59%	382	3 944	86:14	1.22	2.40
2028	3.59%	374	4 318	86:14	1.21	2.53
2029	3.59%	355	4 673	85:15	1.20	2.60
2030	3.59%	498	5 171	83:17	1.28	2.85
2031	3.59%	613	5 784	81:19	1.35	3.09
2032	3.59%	814	6 598	78:22	1.49	3.48
2033	3.59%	1 013	7 612	75:25	1.63	3.84

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
4.8% through 2020, Smooth Increases Target 25% Equity in 2033
(In Millions of Dollars)

For the year ended March 31	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
REVENUES										
General Consumers										
at approved rates	1 396	1 408	1 423	1 438	1 452	1 471	1 490	1 508	1 528	1 548
additional*	0	56	127	204	285	373	468	545	626	713
BPIII Reserve Account	(18)	(21)	(22)	(24)	(13)	0	0	0	0	0
Extraprovincial	408	383	362	390	441	448	484	760	862	880
Other	13	13	13	14	14	14	14	15	15	15
	1 799	1 838	1 903	2 021	2 180	2 306	2 456	2 828	3 031	3 156
EXPENSES										
Operating and Administrative	485	494	542	548	567	574	586	612	620	633
Finance Expense	437	499	513	566	654	777	827	1 087	1 171	1 166
Depreciation and Amortization	415	440	437	448	485	499	520	600	667	675
Water Rentals and Assessments	125	123	111	111	112	111	113	124	127	127
Fuel and Power Purchased	144	142	174	189	203	214	217	250	265	273
Capital and Other Taxes	93	101	109	121	131	134	135	137	139	168
Corporate Allocation	9	9	9	9	9	9	9	9	9	9
	1 707	1 807	1 895	1 991	2 160	2 316	2 407	2 818	2 998	3 051
Non-controlling Interest	24	24	18	16	13	10	8	7	0	(2)
Net Income	116	55	25	46	33	0	58	17	33	103
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	4.80%	4.80%	4.80%	4.80%	4.80%	3.59%	3.59%	3.59%
Cumulative Percent Increase	0.00%	3.95%	8.94%	14.17%	19.64%	25.38%	31.40%	36.11%	40.99%	46.05%
Financial Ratios										
Equity	24%	22%	18%	16%	15%	14%	13%	13%	12%	12%
Interest Coverage	1.20	1.09	1.03	1.05	1.03	1.00	1.05	1.01	1.02	1.07
Capital Coverage	1.03	0.86	0.80	0.88	1.22	1.15	1.31	1.35	1.52	1.72

ELECTRIC OPERATIONS (MH13)
PROJECTED OPERATING STATEMENT
4.8% through 2020, Smooth Increases Target 25% Equity in 2033
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
REVENUES										
General Consumers										
at approved rates	1 568	1 588	1 609	1 629	1 649	1 672	1 694	1 715	1 737	1 758
additional*	804	901	1 003	1 110	1 223	1 344	1 472	1 606	1 746	1 894
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360
Other	16	16	16	16	17	17	17	18	18	19
	3 269	3 372	3 423	3 732	4 127	4 377	4 525	4 681	4 860	5 031
EXPENSES										
Operating and Administrative	646	660	673	705	720	735	748	762	778	794
Finance Expense	1 173	1 167	1 154	1 268	1 563	1 732	1 700	1 710	1 647	1 591
Depreciation and Amortization	679	684	694	741	829	886	895	911	918	921
Water Rentals and Assessments	127	127	127	135	148	151	151	152	153	153
Fuel and Power Purchased	284	300	298	283	271	291	301	299	311	321
Capital and Other Taxes	178	185	194	200	204	206	208	208	212	211
Corporate Allocation	9	9	9	9	9	9	9	7	6	6
	3 095	3 131	3 148	3 340	3 742	4 010	4 011	4 049	4 025	3 996
Non-controlling Interest	(6)	(8)	(8)	(10)	(11)	(13)	(16)	(18)	(20)	(23)
Net Income	167	233	268	382	374	355	498	613	814	1 013
* Additional General Consumers Revenue										
Percent Increase	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%
Cumulative Percent Increase	51.29%	56.71%	62.33%	68.15%	74.18%	80.43%	86.90%	93.60%	100.54%	107.73%
Financial Ratios										
Equity	12%	12%	13%	14%	14%	15%	17%	19%	22%	25%
Interest Coverage	1.11	1.14	1.16	1.22	1.21	1.20	1.28	1.35	1.49	1.63
Capital Coverage	1.87	2.03	2.10	2.40	2.53	2.60	2.85	3.09	3.48	3.84

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
4.8% through 2020, Smooth Increases Target 25% Equity in 2033
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS										
Plant in Service	16 237	17 381	18 305	19 095	22 681	23 407	26 910	30 963	31 516	31 998
Accumulated Depreciation	(5 434)	(5 814)	(6 168)	(6 564)	(7 003)	(7 508)	(8 019)	(8 609)	(9 236)	(9 875)
Net Plant in Service	10 803	11 568	12 137	12 531	15 677	15 900	18 891	22 355	22 280	22 124
Construction in Progress	2 425	3 296	4 743	6 454	5 200	6 525	4 779	1 967	3 154	4 978
Current and Other Assets	1 649	1 669	1 534	1 742	2 172	2 054	2 373	2 440	2 057	2 107
Goodwill and Intangible Assets	188	172	154	139	127	118	107	96	87	81
Regulated Assets	220	213	203	190	180	169	159	149	142	134
	15 285	16 918	18 770	21 056	23 357	24 766	26 309	27 007	27 720	29 424
LIABILITIES AND EQUITY										
Long-Term Debt	10 464	11 904	14 123	16 197	17 226	19 926	21 098	21 831	22 807	24 503
Current and Other Liabilities	1 653	1 760	1 713	1 829	3 004	1 696	2 052	2 046	1 769	1 679
Contributions in Aid of Construction	362	372	382	391	401	413	425	437	449	462
BPIII Reserve Account	18	40	62	86	99	66	33	-	-	-
Retained Earnings	2 584	2 638	2 605	2 651	2 684	2 684	2 741	2 759	2 792	2 894
Accumulated Other Comprehensive Income	204	204	(115)	(98)	(57)	(19)	(41)	(66)	(97)	(114)
	15 285	16 918	18 770	21 056	23 357	24 766	26 309	27 007	27 720	29 424
Equity Ratio	24%	22%	18%	16%	15%	14%	13%	13%	12%	12%

ELECTRIC OPERATIONS (MH13)
PROJECTED BALANCE SHEET
4.8% through 2020, Smooth Increases Target 25% Equity in 2033
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
ASSETS										
Plant in Service	32 572	33 228	33 848	40 307	44 992	46 716	47 170	49 034	49 786	50 231
Accumulated Depreciation	(10 520)	(11 173)	(11 836)	(12 546)	(13 347)	(14 206)	(15 074)	(15 960)	(16 853)	(17 749)
Net Plant in Service	22 052	22 055	22 012	27 760	31 645	32 510	32 095	33 074	32 933	32 482
Construction in Progress	6 748	8 235	9 645	5 009	1 707	1 065	1 525	472	382	553
Current and Other Assets	2 342	2 571	2 413	2 684	2 966	3 344	3 772	3 775	4 823	6 099
Goodwill and Intangible Assets	77	72	68	63	58	54	49	45	40	36
Regulated Assets	129	123	119	112	107	103	100	99	98	98
	31 348	33 057	34 256	35 628	36 484	37 076	37 542	37 464	38 276	39 267
LIABILITIES AND EQUITY										
Long-Term Debt	26 497	27 451	28 854	29 857	30 199	30 381	29 853	29 843	29 847	29 660
Current and Other Liabilities	1 429	1 941	1 458	1 437	1 567	1 611	2 096	1 404	1 391	1 550
Contributions in Aid of Construction	475	488	501	514	527	540	553	567	581	596
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3 061	3 294	3 562	3 944	4 318	4 673	5 171	5 784	6 598	7 612
Accumulated Other Comprehensive Income	(114)	(117)	(120)	(123)	(126)	(129)	(132)	(135)	(141)	(150)
	31 348	33 057	34 256	35 628	36 484	37 076	37 542	37 464	38 276	39 267
Equity Ratio	12%	12%	13%	14%	14%	15%	17%	19%	22%	25%

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
4.8% through 2020, Smooth Increases Target 25% Equity in 2033
(In Millions of Dollars)

For the year ended March 31	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 818	1 859	1 925	2 045	2 193	2 306	2 456	2 828	3 031	3 156
Cash Paid to Suppliers and Employees	(809)	(817)	(902)	(932)	(971)	(988)	(1 004)	(1 073)	(1 099)	(1 147)
Interest Paid	(491)	(506)	(534)	(581)	(687)	(809)	(860)	(1 139)	(1 225)	(1 188)
Interest Received	26	13	16	23	34	37	35	32	29	16
	544	549	506	555	569	546	627	648	736	837
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 316	1 740	2 570	2 390	2 390	3 000	1 800	1 390	1 390	1 970
Sinking Fund Withdrawals	410	103	16	-	12	412	185	268	670	155
Retirement of Long-Term Debt	(610)	(217)	(312)	(336)	(330)	(1 442)	(305)	(633)	(673)	(431)
Other	(116)	(11)	(12)	(12)	(11)	(22)	(11)	(57)	15	(6)
	1 000	1 616	2 261	2 043	2 061	1 948	1 669	969	1 402	1 688
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 578)	(2 039)	(2 439)	(2 511)	(2 413)	(2 074)	(2 061)	(1 352)	(1 735)	(2 300)
Sinking Fund Payment	(194)	(114)	(184)	(159)	(224)	(217)	(223)	(245)	(338)	(240)
Other	(14)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(1 786)	(2 175)	(2 644)	(2 691)	(2 658)	(2 325)	(2 314)	(1 627)	(2 103)	(2 570)
Net Increase (Decrease) in Cash	(243)	(10)	123	(93)	(29)	168	(17)	(10)	35	(46)
Cash at Beginning of Year	25	(218)	(227)	(104)	(197)	(226)	(58)	(75)	(85)	(51)
Cash at End of Year	(218)	(227)	(104)	(197)	(226)	(58)	(75)	(85)	(51)	(96)

ELECTRIC OPERATIONS (MH13)
PROJECTED CASH FLOW STATEMENT
4.8% through 2020, Smooth Increases Target 25% Equity in 2033
(In Millions of Dollars)

For the year ended March 31	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 269	3 372	3 423	3 732	4 127	4 377	4 525	4 681	4 860	5 031
Cash Paid to Suppliers and Employees	(1 177)	(1 211)	(1 227)	(1 256)	(1 273)	(1 311)	(1 331)	(1 341)	(1 369)	(1 390)
Interest Paid	(1 185)	(1 188)	(1 180)	(1 312)	(1 625)	(1 813)	(1 796)	(1 826)	(1 739)	(1 702)
Interest Received	17	26	31	42	59	76	85	98	79	98
	923	999	1 048	1 206	1 287	1 329	1 482	1 611	1 830	2 038
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 990	1 380	1 390	980	390	380	160	(10)	(20)	(50)
Sinking Fund Withdrawals	25	-	425	-	-	60	250	700	13	30
Retirement of Long-Term Debt	(290)	-	(450)	-	-	(60)	(220)	(700)	(13)	-
Other	1	1	0	1	1	1	2	3	(16)	(16)
	1 726	1 381	1 365	981	391	381	192	(7)	(36)	(36)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 338)	(2 135)	(2 021)	(1 812)	(1 372)	(1 070)	(901)	(798)	(650)	(603)
Sinking Fund Payment	(260)	(287)	(313)	(318)	(340)	(358)	(372)	(376)	(356)	(369)
Other	(30)	(30)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)
	(2 628)	(2 453)	(2 360)	(2 155)	(1 739)	(1 454)	(1 299)	(1 201)	(1 032)	(1 000)
Net Increase (Decrease) in Cash	21	(73)	53	31	(60)	256	375	403	762	1 002
Cash at Beginning of Year	(96)	(75)	(148)	(95)	(64)	(124)	132	507	911	1 672
Cash at End of Year	(75)	(148)	(95)	(64)	(124)	132	507	911	1 672	2 674

PUB/MH I-30

Preamble: **The Corporation states that "by implementing these further cost containment initiatives, Manitoba Hydro has maintained projected annual rate increases for each year of MH13-1 at the same level as those projected in MH12, namely 3.95%".**

MH13-1 reflects net losses in 2018 through 2022 totaling $245 million

d) Please provide details on the specific cost containment measures referred to and the savings realized for each one for a five year period starting in 2012/13.

ANSWER:

The Corporation has previously undertaken a number of cost savings measures including the following:

- Leveraging technology to improve efficiency External hiring freeze
- Restrictions on out-of-province travel
- Overtime restrictions (except to respond to system emergencies, to maintain the safety and reliability of the energy system and to complete work projects for efficiency reasons)
- Reductions in community sponsorships and donations

As noted on pages 3-4 of the Application, MH13 includes cost containment provisions that limit OM&A cost increases to 1% starting in 2015/16 and continuing through 2020/21, which reduce OM&A expenditures by approximately $600 million over the forecast period. The Corporation is currently planning further cost containment measures as part of the detailed annual budgeting process to achieve these cost reductions. Each Business Unit is responsible for identifying and implementing initiatives to manage the ongoing cost pressures. These initiatives include, but are not limited to: the management of attrition and retirements, work elimination and organizational consolidation, and changes in work processes such as further integrating the electric and gas regulatory processes.