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Tab #	Description	Reference
Load Forecast and DSM		
48.	*Load Forecast Graphs – Gross Net of DSM* *Total Customers Table*	***PUB/MH I-56;*** ***PUB MFR 65 (Updated), Table 4 – p. 5***
49.	*Price & GDP Elasticities* *Daymark Assessment of Price Elasticity*	***PUB MFR 65 (Updated), p. 57;*** ***Daymark: Load Forecast Review, p. 33***
50.	*Load Forecast Graph Residential – Net of DSM* *Daymark – Population and Customer Forecast Error* *Home Space and Water Heating Costs & Comparison*	***PUB/MH I-56;*** ***Daymark: Load Forecast Review, p. 31;*** ***MH Home Space Heating Costs (Nov 2017);*** ***MH Home Water Heating Costs (Nov 2017);*** ***PUB/MH I-129 (a-c)***
51.	*Load Forecast Graph GSMM – Net of DSM*	***PUB/MH I-56***
52.	*Top Consumers Load Forecast Graphs* *Impact on Financials of Change in Loads*	***PUB/MH I-56;*** ***PUB MFR 65 (Updated), p. 21;*** ***Tab 7, p. 2;*** ***GSL Energy Rates 2018-2026, MH16 Updated & Interim (with PUB Advisor Calculations);*** ***PUB/MH II-50 (a-b);*** ***COALITION/MH I-25 (a-b)***
53.	*Load Forecast Accuracy*	***Daymark: Load Forecast Review, p. 41-44;*** ***PUB/MH I-57;*** ***PUB MFR 65 (Updated), p. 48-49***
54.	*DSM Capex* *DSM Impact on Retained Earnings* *BCG on DSM*	***DSM Plan 2016/17 (GRA Appendix 7.2), p. vi, ix;*** ***DSM Plan 2016/17 (GRA Appendix 7.2), Appendix A.3 – 2016 DSM Plan Annual Utility Costs;*** ***PUB MFR 72 – Attachment, p. 218;*** ***PUB MFR 77;*** ***PUB MFR 72 – Attachment, p. 215, 280*** ***DSM Plan 2016/17 (GRA Appendix 7.2), iv – Electric DSM Levelized Costs;*** ***PUB/MH I-131 (b-c);*** ***2017/18 & 2018/19 GRA,***

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		Appendix 5.4, p. 2; COALITION/MH I-48 (a-f); 2017/18 Power Smart Plan, p. 2
55.	*Fuel Switching*	***2012/13 GRA, Appendix 26, p. 24; PUB/MH I-128 (a) – Attachments, p. 213; PUB/MH II-56; PUB/MH II-60***

Tab #	**Description**	**Reference**
Export Revenue		
56.	*RPAA Supply & Demand Tables* *Classification of Wind Purchase Costs in COSS*	***PUB/MH II-45 (a-e) Attachment 1, p. 19-26; 2016/17 Supplemental Filing – Attachment 17 MFR 2 (2015 RPAA Supply & Demand Tables); COSS MH Final Submission (August 12, 2016), p. 3***
57.	*Water Flow Records, Methodology & Forecasts*	***Tab 7, p. 26; 2017/18 & 2018/19 GRA, Appendix 7.4 (Updated), p. 2; Supplement to Tab 3, p. 10; COALITION/MH I-62 (a-e); PUB/MH I-19; PUB/MH II-37 (a-b); MH Q2 2017 Report, p. 1-2***
58.	*Drought Sensitivity Analysis*	***PUB/MH II-39; PUB/MH I-48 (b); PUB/MH II-40***
59.	*Changes in Export Revenues & Forecasts*	***Tab 3, p. 14; PUB/MH I-153 (b); COALITION/MH I-99 (a-b); PUB MFR 80; Supplemental Filing to MH's 2015/16 & 2016/17 GRA (November 18, 2015), p. 13; PUB/MH I-8 (e) (2014/15 & 2015/16 GRA); 2015/16 & 2016/17 GRA, Appendix 3.3 (Jan 23, 2015), p. 7; Supplement to Tab 3, p. 7, 10, 11; 2017/18 & 2018/19 GRA, Appendix 3.1, p. 16***

60.	*Surplus Energy and Capacity*	***COSS Exhibit MH-20 p.28 (with PUB Advisor additions); PUB/MH I-50 (a-c); PUB/MH II-46; PUB/MH II-32 (b)***
61.	*Export Revenue Enhancement*	***2017/18 & 2018/19 GRA, PUB MFR 72 – Attachment, p. 225-233; PUB/MH II-36 (a-e); 2015 MH GRA Transcript, p. 1071-1074***
62.	*Delay of Keeyask*	***Manitoba CBC News Story (Nov 13, 2017) – Project Delay Possible; 2017/18 & 2018/19 GRA – PUB MFR 72 – Attachment, p. 553***
63.	*Export Contract List* *IESO Negotiated Settlements*	***2017/18 & 2018/19 GRA – Appendix 3.1, p. 16; IESO Negotiated Settlements (Nov 21, 2017)***

Tab #	**Description**	**Reference**
Operating, Maintenance & Administrative Expense		
64.	*OM&A Forecast* *Capitalized OM&A*	***Tab 6, p. 20-25; PUB/MH II-8; PUB/MH I-16; PUB/MH II-9; PUB/MH I-12***
65.	*Cost Containment Measures*	***PUB MFR 33; 2016/17 Supplemental Filing Attachment 33 – MFR 2; Tab 5, p. 45-51; PUB/MH I-13 (a-c)***
66.	*Voluntary Departure Program & Impact on Service Levels*	***PUB/MH I-17 (a); PUB MH I-17 (b-c); PUB/MH II-6 (a-b); PUB/MH II-10; PUB/MH II-4 (a-d)***
67.	*EFT – Staffing Levels*	***PUB MFR 34; PUB/MH I-78 (a-b); MIPUG MFR 8; PUB/MH I-9 (a-b); MH Electric GRA Application 2015, MH Exhibit #103 (June 12, 2015)***

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68.	*OM&A Expense Analysis 2016/17 – Actual vs. Forecast*	***PUB/MH I-10; PUB/MH I-14 (a-b); PUB/MH II-7 (a-b); PUB MFR 41; Tab 6, p. 36-37; COALITION/MH I-94 (b-f); PUB MFR 32 and 42; PUB/MH I-15 (a-b);***
69.	*Compensation/Average Salary by Business Unit*	***PUB MFR 36***

Tab #	**Description**	**Reference**
Payments to Government		
70.	*Payments to Province & Municipalities*	***PUB MFR 44***
71.	*Calculations – Net Debt Guarantee Fee & Water Rental Payments*	***PUB MFR 45; PUB MFR 46***
72.	*Payments to Government Related to Keeyask & Bipole III*	***PUB/MH I-21***
73.	*Capital & Other Tax Capital Tax Calculation*	***Tab 6, p. 34; COALITION/MH I-91 (a-b)***

Tab #	**Description**	**Reference**
Depreciation		
74.	*Depreciation Detail & Charges – ASL & ELG*	***PUB/MH I-18 (a-b); COALITION/MH I-85 (c-e)***
75.	*Book Accumulated Depreciation Surplus Depreciation Rate Schedules – ASL vs. ELG*	***PUB/MH II-15 (a-b); MIPUG/MH I-22 (a) & (b) (2014/15 & 2015/16 GRA); 2015/16 & 2016/17 GRA, Appendix 5.6, p. 7-14***
76.	*ASL vs. ELG Depreciation Expense*	***PUB/MH II-2 (a-c), p. 9-10***
77.	*Regulatory Deferral Account Balances*	***MIPUG/MH I-6 (c)***

Tab #	**Description**	**Reference**
Regulatory Deferral Accounts		
78.	*Conawapa Costs and Status*	***PUB/MH II-12 (a-c)***
79.	*Conawapa Costs*	***COALITION/MH I-105***

80.	*Conawapa – IAS 36 Impairment*	***PUB/MH I-22 (a-b)***
81.	*Conawapa Impact on IFF16U*	***MIPUG/MH I-22***
82.	*IFF16U Assuming Write Off of Conawapa*	***PUB/MH II-12 (d)***
83.	*Regulatory Deferral Balances – Reported at March 31, 2017 & IFF16-Update*	***MHEB 65th Annual Report, p. 72-74;*** ***COALITION/MH I-104 (a-c)***
84.	*Other Expense Detail – Net Movement*	***COALITION/MH I-94 (b-f)***
85.	*Net Movement of Regulatory Deferral Accounts*	***MIPUG/MH I-6 (b);*** ***MIPUG/MH I-6 (c)***
86.	*Continuity of Financial Forecast Presentation with past GRA's for Rate Setting Purposes*	***PUB/MH I-1 (a-f)***
87.	*Schedule of Regulatory Deferral Account Balances – IFF16 Update with Interim*	***PUB/MH II-1 (a-b)***
88.	*Approval for Disposition of the Bipole III Reserve Funds*	***PUB/MH I-152 (a);*** ***PUB/MH I-152 (b)***
89.	*Alternative Treatments of ELG/ASL Regulatory Deferral Account*	***COALITION/MH I-138 (a-b)***
90.	*Regulatory Treatment of Restructuring Costs*	***MIPUG/MH I-6 (e-k)***

Tab #	**Description**	**Reference**
Business Operations Capital		
91.	*Total Capital Spending* *MH Reputational Risk* *MH's corporate mission* *MH's capital budgeting and prioritization*	***Tab 5, p. 17;*** ***PUB/MH I-73 (a-b);*** ***PUB/MH II-85 (a-b);*** ***PUB/MH I-119 (a-e)***
92.	*Asset Management Implementation Phases*	***PUB/MH I-71 (a-c);*** ***PUB/MH I-86 (a-b)***
93.	*Corporate Value Framework and Use of Copperleaf*	***PUB/MH II-65 (a-b)***
94.	*Evaluation of MH's Asset Management - UMS Report*	***2017/18 & 2018/19 GRA, Appendix 5.1, p. 6-9***
95.	*Deferral of projects* *Change in Business Operations Capital CEF15 to CEF16* *Capital targets extrapolated*	***PUB/MH I-123 (a-b);*** ***PUB/MH II-62;*** ***PUB/MH II-74 (a-c)***
96.	*Optimization and allocation of capital among business units* *Optimization based on age or condition assessment*	***PUB/MH II-66 (a-d);*** ***PUB/MH II-67;*** ***PUB/MH II-78;*** ***PUB/MH II-79 (a-b);***

		PUB/MH II-79 (c)
97.	*Capital investment scenarios* *Business Operations Capital by Category* *Customer Survey on rates and capital investment*	***PUB/MH I-85 (a-b);*** ***Tab 5, p. 26;*** ***PUB/MH I-124***
98.	*Remaining life after pre-emptive replacement* *Determining useful life* *Asset replacement categorization*	***PUB/MH I-121;*** ***PUB/MH II-80 (a-b);*** ***PUB/MH II-82 (a-b)***
99.	*Impacts to SAIDI and SAIFI*	***PUB/MH II-75 (a-c);*** ***PUB/MH II-81 (a-g)***
100.	*Probability and consequence* *Capital budget ranking tool*	***PUB/MH II-72 (d-k);*** ***PUB/MH I-80 (a-b);*** ***PUB/MH II-72 (a-k)-Attachment 1;*** ***PUB/MH II-73 (a-b)***
101.	*Capacity hot spots*	***PUB/MH I-77 & Attachment***
102.	*Project cost increases*	***PUB/MH II-84 (a-c) & Attachment 1***
103.	*Volitional vs non-volitional capital*	***PUB/MH I-117 (b-d)***
104.	*Asset Condition Assessment responses to directives*	***PUB/MH I-89 (a-c)***
105.	*Capital spending projection* *Impact of $100M decrease in capital*	***2017/18 & 2018/19 GRA, Appendix 5.4, p. 2;*** ***PUB/MH II-33 (b)***

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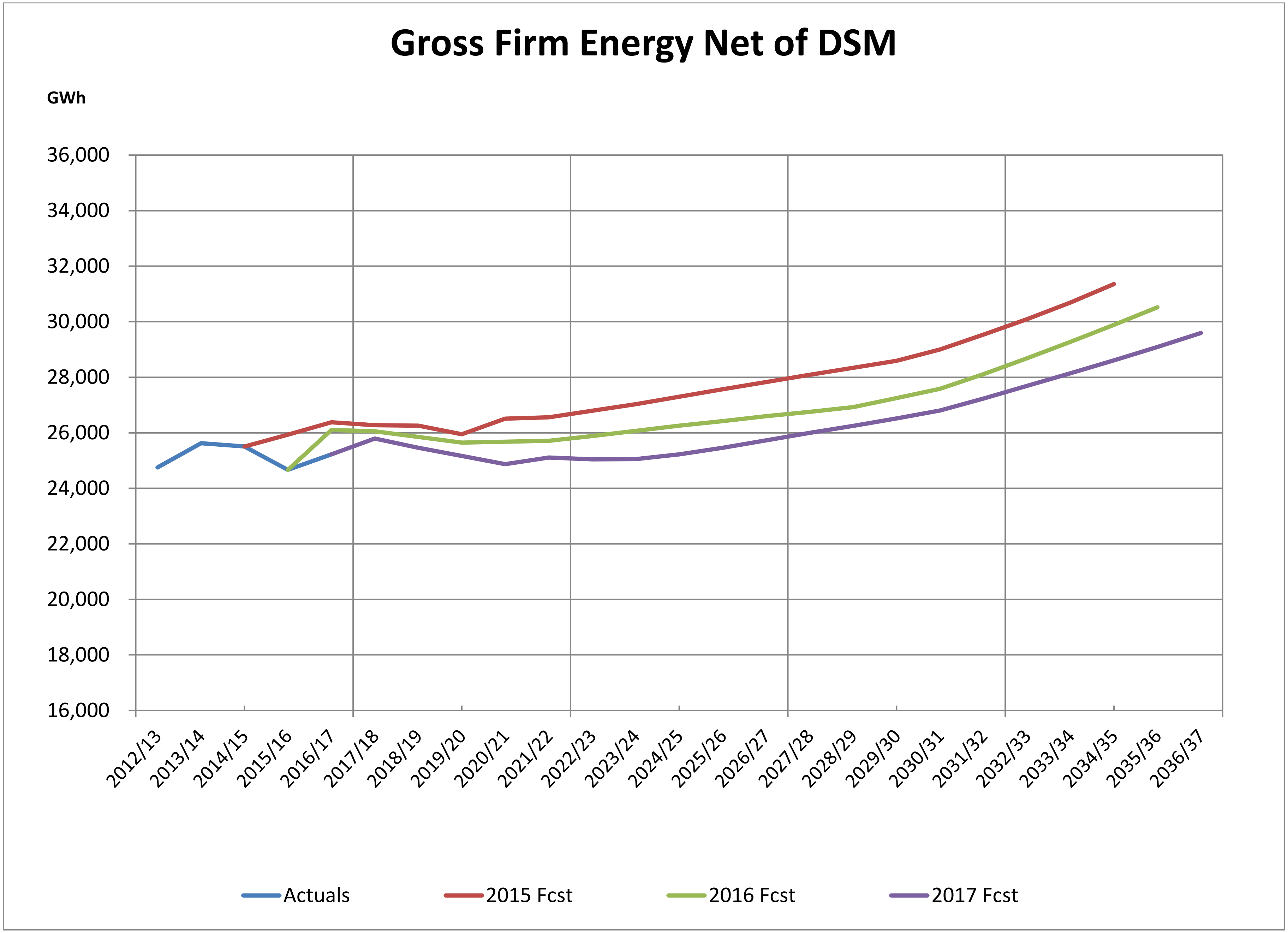
Gross Firm Energy Net of DSM
GWh
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
18,000
16,000
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30
2030/31
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2032/33
2033/34
2034/35
2035/36
2036/37
Actuals
2015 Fcst
2016 Fcst
2017 Fcst

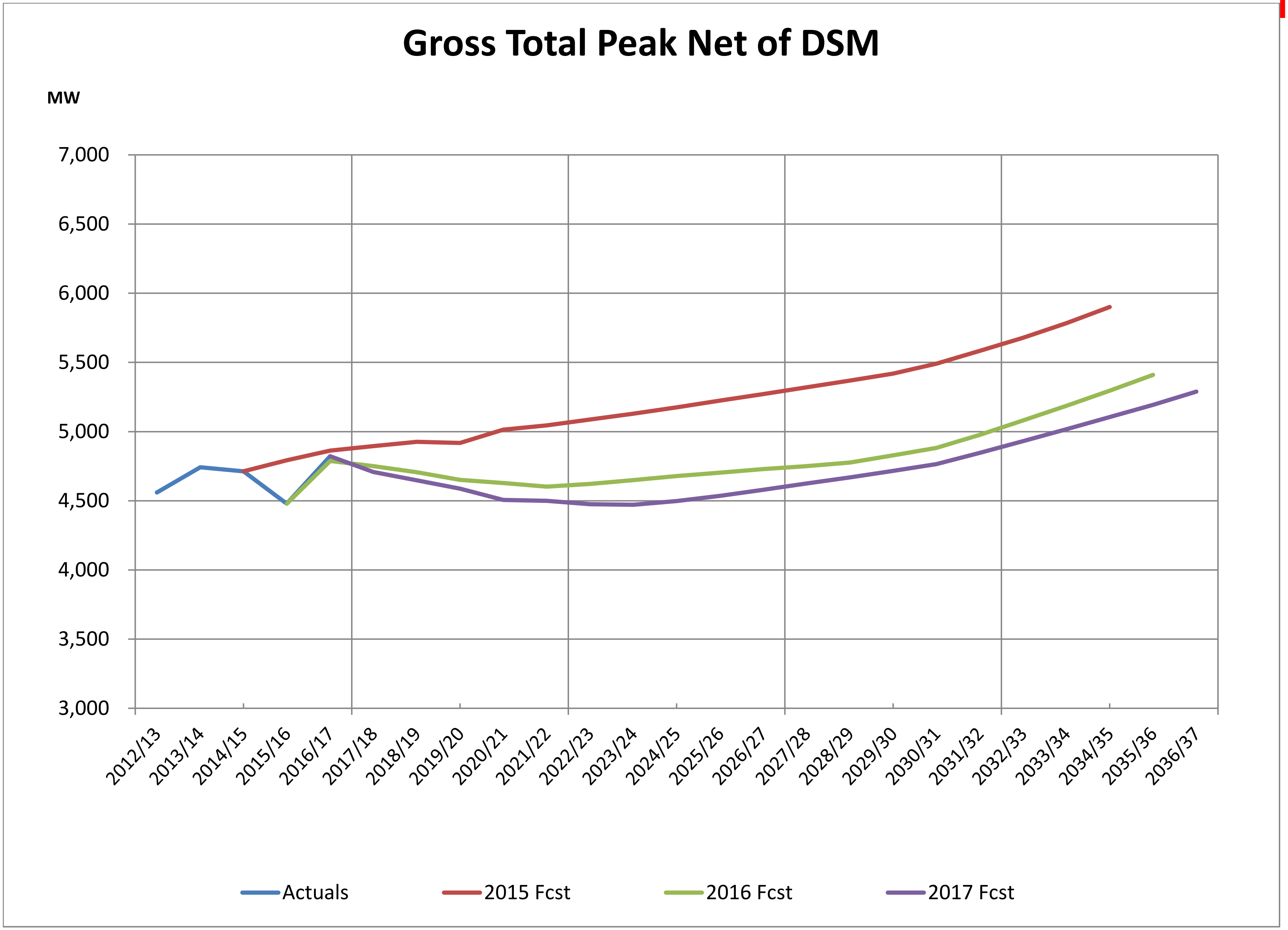
Gross Total Peak Net of DSM
MW
7,000
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30
2030/31
2031/32
2032/33
2033/34
2034/35
2035/36
2036/37
Actuals
2015 Fcst
2016 Fcst
2017 Fcst

Table 4 - General Consumers Sales Customers

GENERAL CONSUMERS SALES (Average Customers)
History and Forecast
2006/07 - 2036/37

Fiscal	Residential			General Service					Lighting	Total
Year	Basic	Diesel	Seas	Mass Mkt	Top Cons	Diesel	Seas	SEP		Custs
2006/07	427,886	525	20,312	63,596	26	169	783	28	1129	514,455
2007/08	432,144	531	20,437	63,855	26	175	798	27	1142	519,135
2008/09	437,263	540	20,648	64,140	26	178	818	24	1175	524,811
2009/10	441,710	539	20,839	64,758	26	177	830	24	1191	530,095
2010/11	445,882	550	20,950	65,193	26	176	842	24	1184	534,828
2011/12	450,748	568	20,844	65,546	32	174	847	26	1155	539,939
2012/13	456,130	577	20,731	65,974	31	175	850	28	1164	545,660
2013/14	462,274	583	20,757	66,569	31	179	861	28	1157	552,438
2014/15	468,499	583	20,626	67,042	30	183	872	28	1196	559,060
2015/16	474,153	583	20,176	67,395	32	184	882	30	1208	564,643
2016/17	480,365	586	19,707	67,676	26	181	923	30	1218	570,712
10 Year	5,248	6	-61	408	0	1	14	0	9	5,626
Avg Gr.	1.2%	1.1%	-0.3%	0.6%	0.0%	0.7%	1.7%	0.7%	0.8%	1.0%
2017/18	486,318	588	19,454	68,166	26	184	945	30	1,228	576,938
2018/19	492,793	593	19,284	68,695	26	184	960	30	1,233	583,796
2019/20	499,348	596	19,114	69,232	26	185	975	30	1,238	590,744
2020/21	505,856	600	18,944	69,765	26	185	990	30	1,243	597,638
2021/22	512,130	603	18,774	70,289	26	186	1005	30	1,248	604,291
2022/23	518,186	607	18,604	70,800	26	187	1020	30	1,253	610,713
2023/24	524,161	611	18,434	71,279	26	187	1035	30	1,258	617,020
2024/25	530,091	614	18,264	71,743	26	188	1050	30	1,263	623,269
2025/26	535,964	618	18,094	72,206	26	189	1065	30	1,268	629,460
2026/27	541,760	622	17,924	72,670	26	190	1080	30	1,273	635,574
10 Year	6,139	4	-178	499	0	1	16	0	5	6,486
Avg Gr.	1.2%	0.6%	-0.9%	0.7%	0.0%	0.5%	1.6%	0.0%	0.4%	1.1%
2027/28	547,464	625	17,754	73,133	26	190	1095	30	1,278	641,595
2028/29	553,102	629	17,584	73,595	26	191	1110	30	1,283	647,549
2029/30	558,690	632	17,414	74,059	26	192	1125	30	1,288	653,456
2030/31	564,211	636	17,244	74,522	26	193	1140	30	1,293	659,295
2031/32	569,654	639	17,074	74,986	26	193	1155	30	1,298	665,055
2032/33	575,015	643	16,904	75,449	26	194	1170	30	1,303	670,734
2033/34	580,305	647	16,734	75,912	26	195	1185	30	1,308	676,341
2034/35	585,544	650	16,564	76,377	26	196	1200	30	1,313	681,900
2035/36	590,730	654	16,394	76,842	26	196	1215	30	1,318	687,404
2036/37	595,837	657	16,224	77,308	26	197	1230	30	1,323	692,831
20 Year	5,774	4	-174	482	0	1	15	0	5	6,106
Avg Gr.	1.1%	0.6%	-1.0%	0.7%	0.0%	0.4%	1.4%	0.0%	0.4%	1.0%

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Price / Income / GDP Elasticity

The economic effects of price, income and GDP have been incorporated into the 2017 forecast. The elasticity of each has been estimated from econometric modeling. See the Methodology section for more details. A summary of the elasticities found is:

	Price Elasticity	Real Income Elasticity	Real GDP Elasticity
Residential Basic	-0.28	0.30	
GS Mass Mkt Small/Medium	-0.13		0.55
GS Mass Mkt Large	-0.46		0.29
GS Top Consumers	-0.37		0.62
Gross Firm Energy	-0.27	0.10	0.36

Demand Side Management (DSM) in the Forecast

This forecast reflects future DSM savings associated with existing Provincial building codes and improved equipment efficiency standards and regulations (Codes and Standards). This is the only effect of DSM initiatives that is specifically accounted for in the forecast.

Savings due to DSM programs to date are embedded in the historical data that is the basis for this forecast. The current level of past achieved DSM savings is assumed to remain in place throughout the future. Future DSM savings arising from future Power Smart offerings and market engagement above the current level and incremental to the above mentioned Codes and Standards are not reflected in this forecast. They are accounted for separately in Manitoba Hydro's Power Smart Plan and Power Resource Plan.

As a result, historical growth rates in this document are not directly comparable to future growth rates because the history includes the effect of past program-based DSM initiatives, but the forecast does not.

For customers involved in Load Displacement and Alternative Energy initiatives, the forecast excludes the effect of the initiatives, and projects the load without the savings due to the initiatives.

Table 1: MH Estimated Price, Income, and GDP Elasticities [48]

	PRICE ELASTICITY	REAL INCOME ELASTICITY	REAL GDP ELASTICITY
Residential Basic	-0.28	0.30	
GS Mass Market Small/Medium	-0.13		0.55
GS Mass Market Large	-0.46		0.29
GS Top Consumers	-0.37		0.62
Gross Firm Energy	**-0.27**	**0.10**	**0.36**

Daymark found that some of the elasticities reported by MH may be incorrectly estimated for different reasons. The econometric model used for the energy forecast includes a variable that estimates the price elasticity of residential customers and that coefficient exhibits a multicollinearity issue. MH reported the price elasticity of -0.28 using the model with the multicollinearity issue. The regression model used for estimating average usage per customer has multicollinearity issues mainly due to the use of highly correlated independent variables - the log transformation income, saturation, and trend variables are highly correlated with each other. Daymark calculated the variance inflation factor (VIF) of the independent variables used in MH's residential regression model, which assesses how much the variance of an estimated regression coefficient increases if the predictors are correlated. A VIF value of 5 or greater indicates a reason to be concerned about multicollinearity[49]. As presented in Table 3, The VIF values of the independent variables of income, saturation, and trend variables are greater than 25 indicating that multicollinearity exists in the model.

Daymark estimated residential price elasticity to be -0.34 when the variables causing the multicollinearity were removed from the equation. Although multicollinearity doesn't affect the overall fit of the model, or result in bad forecasts of the dependent variable, it does produce unreliable coefficient estimates. As a result of the multicollinearity in MH's residential average usage model, the coefficients associated with electricity price and income, which are interpreted as price elasticity and income elasticity, may be incorrectly estimated[50].

Similarly, the price elasticity estimated for the top consumers sector, through the conservative PLIL method, is lower than it would be if it were estimated using the PLIL

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[48] 2017 Load Forecast Report, Page 57.

[49] http://blog.minitab.com/blog/adventures-in-statistics-2/what-are-the-effects-of-multicollinearity-and-when-can-i-ignore-them

[50] Ibid.

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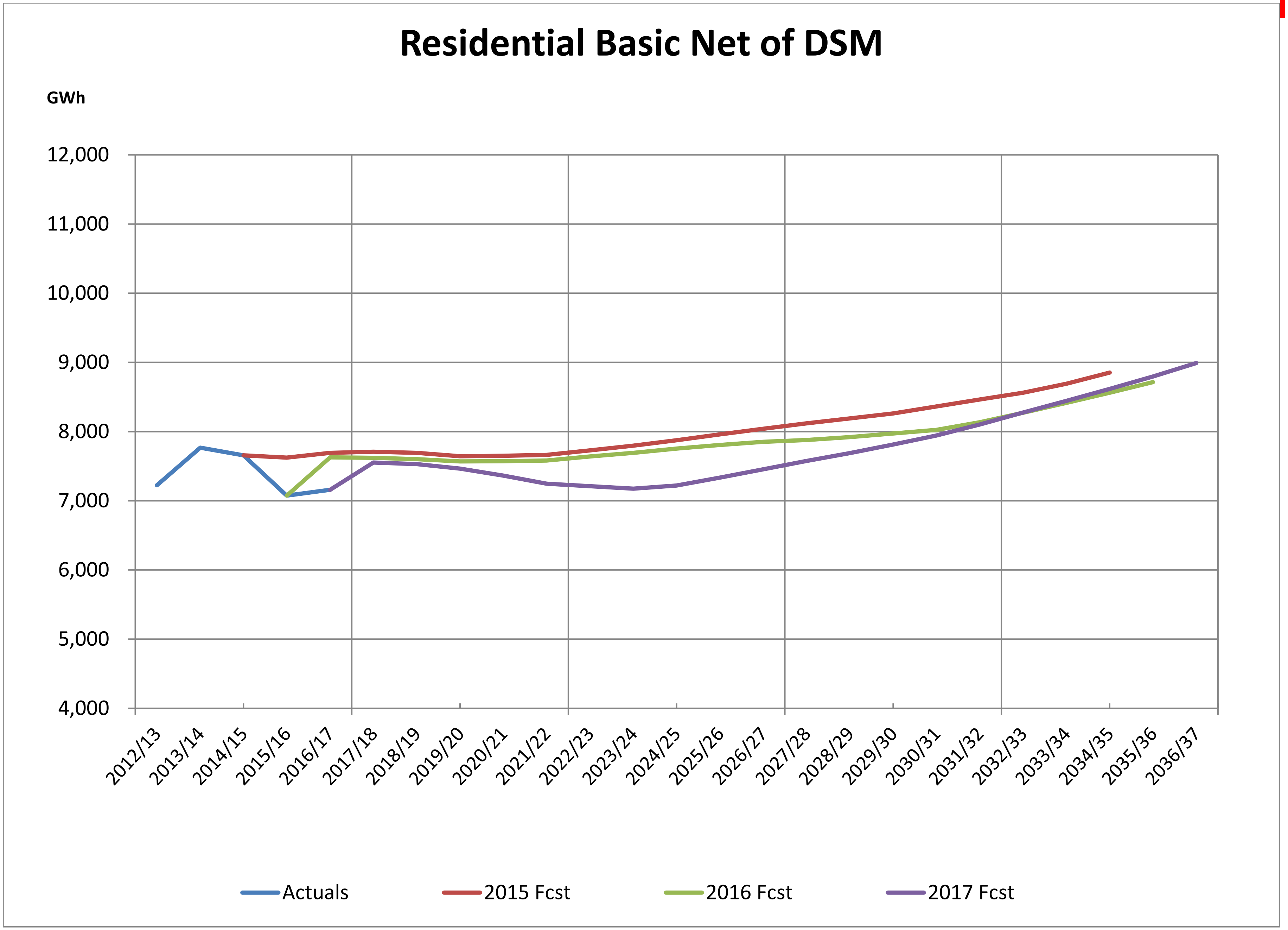

Residential Basic Net of DSM
GWh
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30
2030/31
2031/32
2032/33
2033/34
2034/35
2035/36
2036/37
Actuals
2015 Fcst
2016 Fcst
2017 Fcst

advance. The figure shows that the average percentage error varies, on average, from 0.033% in 1-year ahead comparisons to 2.01% in 10-year ahead forecasts.[45] The positive error percentages denote that the actual population is higher than the forecasted population. Similarly, the average error percentage on forecasts for residential customer counts varies from 0.35% in 1-year ahead forecasts to 4.5% in the 10-year ahead forecasts.[46] Since the load forecast for the residential sector is the product of the customer count forecast and the average usage forecast, the use of a lower-than-actual customer count forecast will result in a lower residential load forecast. Moreover, since residential customer count is one of the predictor variables for forecasting the number of GSMM customers, the use of under-forecasted residential customer numbers results in lower-than-actual GSMM customer counts, which in turn produces a lower GSMM load forecast.

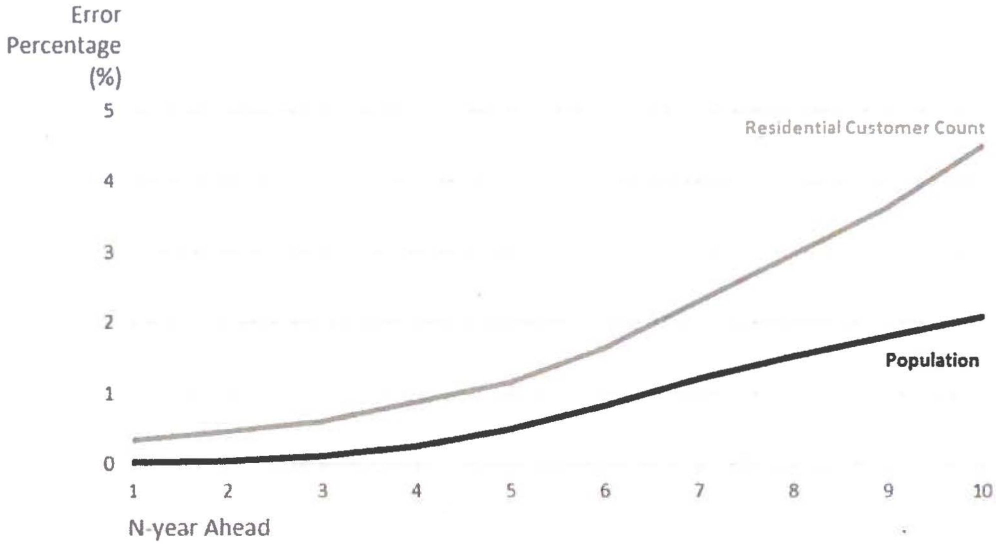


Figure 10: Average N-year Ahead Error Forecast, Population and Residential Customer Count

~~[CONFIDENTIAL END]~~

[redacted]

[46] The error percentage for residential customers only uses data after 2004 as MH reported a structural change in its Residential customer forecast in 2004.

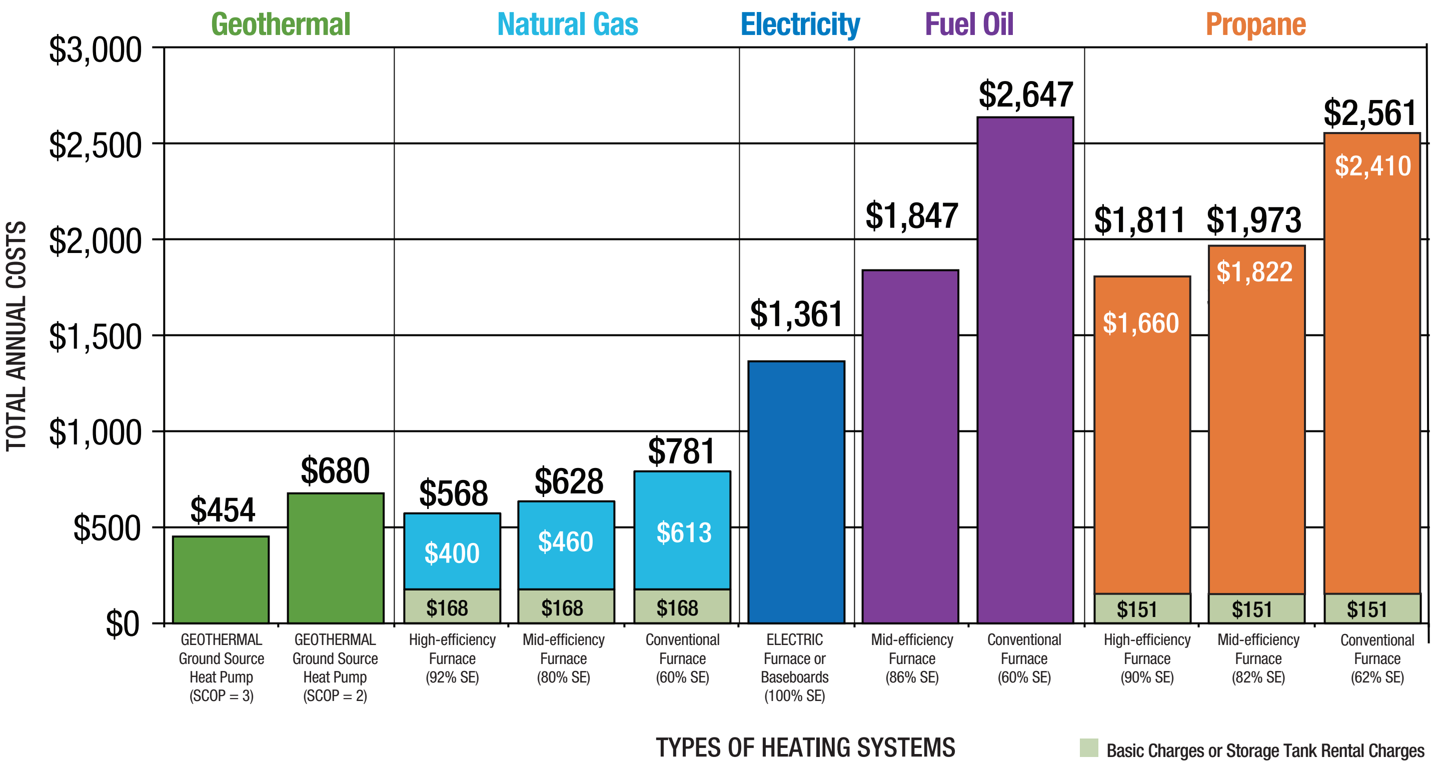
Wondering about your energy options for space heating?

The chart below shows an example of space heating costs that are based on an average single family residence, at rates in effect November 1, 2017.

1. Consult the charts to identify the costs of your current space heating system.
2. Review the annual energy costs of other systems to see how your costs compare.
3. Consult the accompanying notes on pages 2, 3 and 4 for guidance if you are thinking of switching space heating systems or building a new home.
4. Visit **hydro.mb.ca/heating** and use the online calculator to get a customized estimate for your specific home's annual and total lifetime space heating costs based on different heating systems and energy sources.

Annual Space Heating Costs

(Average single family residence)



Energy rates

as of November 1, 2017.

Natural gas:	**$0.2293**/cubic metre
Electricity:	**$0.08196**/kilowatt-hour
Fuel oil:	**$1.023**/litre
Propane:	**$0.638**/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**

Space heating annual costs shown in the chart above are based on "point-in-time" prices as noted.

The annual space heating costs presented in the chart exclude the cost of converting to a different heating system, which may be significant.

See page 3 if you are thinking of changing your heating system.

Depending on your supplier, propane and fuel oil prices can fluctuate on a daily basis.

Manitoba Hydro

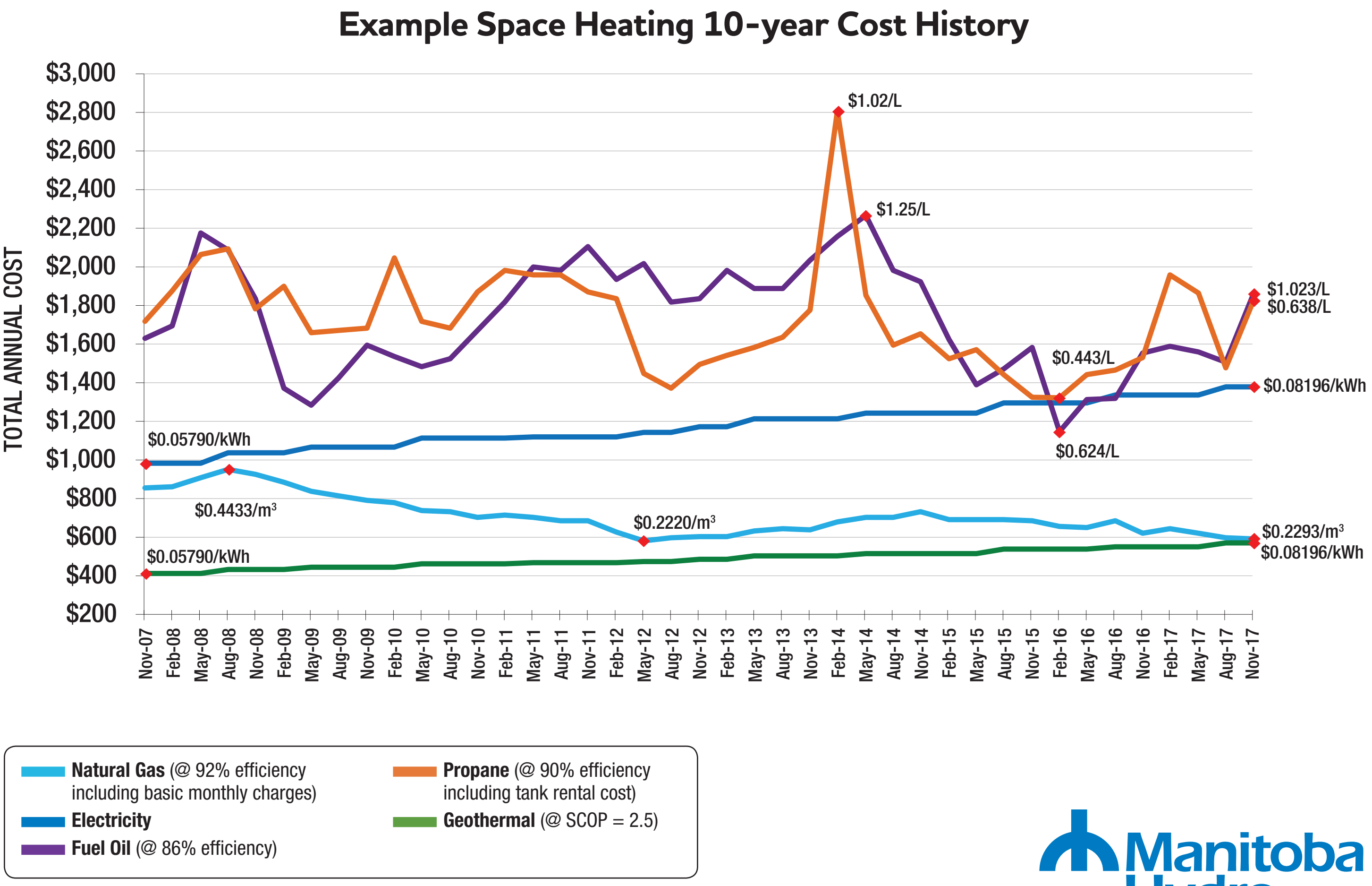
Annual cost estimates

The space heating costs shown in the charts are based on the amount of energy required to heat the average single-detached home that is served by Manitoba Hydro. The average single-detached home on Manitoba Hydro's system requires approximately 60 Gigajoules (output) of energy for space heating. Your space heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness, lifestyle, and energy rates paid. If you think your space heating usage is higher or lower than the average shown here, please factor up or down the operating costs of the various heating systems shown in the chart. The costs shown are relative, illustrative and for general comparison purposes only.

The charts on the first page present annual costs as if all energy rates remained fixed for the coming year at the rates in effect on November 1, 2017.

Your actual annual energy costs will vary. Natural gas rates change four times per year, electricity rates typically change on an annual basis and depending on your supplier, propane and oil rates can change daily. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0831 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2293 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

The chart below shows a 10 year history of annual operating costs of various energy sources and space heating systems. The chart also shows the minimum and maximum energy prices for a given point in time by energy source over the 10 year period. The energy prices shown are provided as reference points to show the relationship between the energy price at a given time and the annual operating costs of a specific heating system.



Key points if you are thinking of changing heating systems

Is it economically feasible?

Note that the costs of switching to another system to heat your home may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a space heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue gas venting

When gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

Chimney ventilation

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase unwanted humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

Converting to a high efficiency gas furnace or to electric heat will reduce the uncontrolled ventilation through the chimney. Along with upgrading to a high efficiency gas furnace, if you remove your existing conventional gas water heater at the same time and install a power-vent gas or electric water heater you will completely eliminate the uncontrolled chimney ventilation.

When upgrading your space heating system to a high efficiency gas furnace you don't have to change your water heater. In many cases the existing chimney will be sufficient to continue to operate your conventional gas water heater, in some cases you may need to install a chimney liner. If you are unable to upgrade the chimney then a power-vent gas water heater may be an option for you. Speak with a licensed and reputable heating contractor about your water heating options for your specific home.

Increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety – Because your family comes first!".

Calculate your payback

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new heating system to pay for itself.

Explanation of technical information in the charts

- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. This charge may not apply to all customers and may vary by propane supplier.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

ENERGY RATES — in effect November 1, 2017

Commodity charge		**Heating value**
Natural gas	$0.2293/cubic metre	35,310 Btu/cubic metre
Electricity	$0.08196/kilowatt-hour	3,413 Btu/kilowatt-hour
Fuel oil	$1.023/litre	36,500 Btu/litre
Propane	$0.638/litre	24,200 Btu/litre

The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning, and ongoing maintenance practices.

- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.0831 per cubic metre. Primary Gas currently comprises 92 per cent of the gas supplied (supplemental gas is 8 per cent.)
- Taxes are not included in the examples.

Available in accessible formats upon request.

Manitoba Hydro

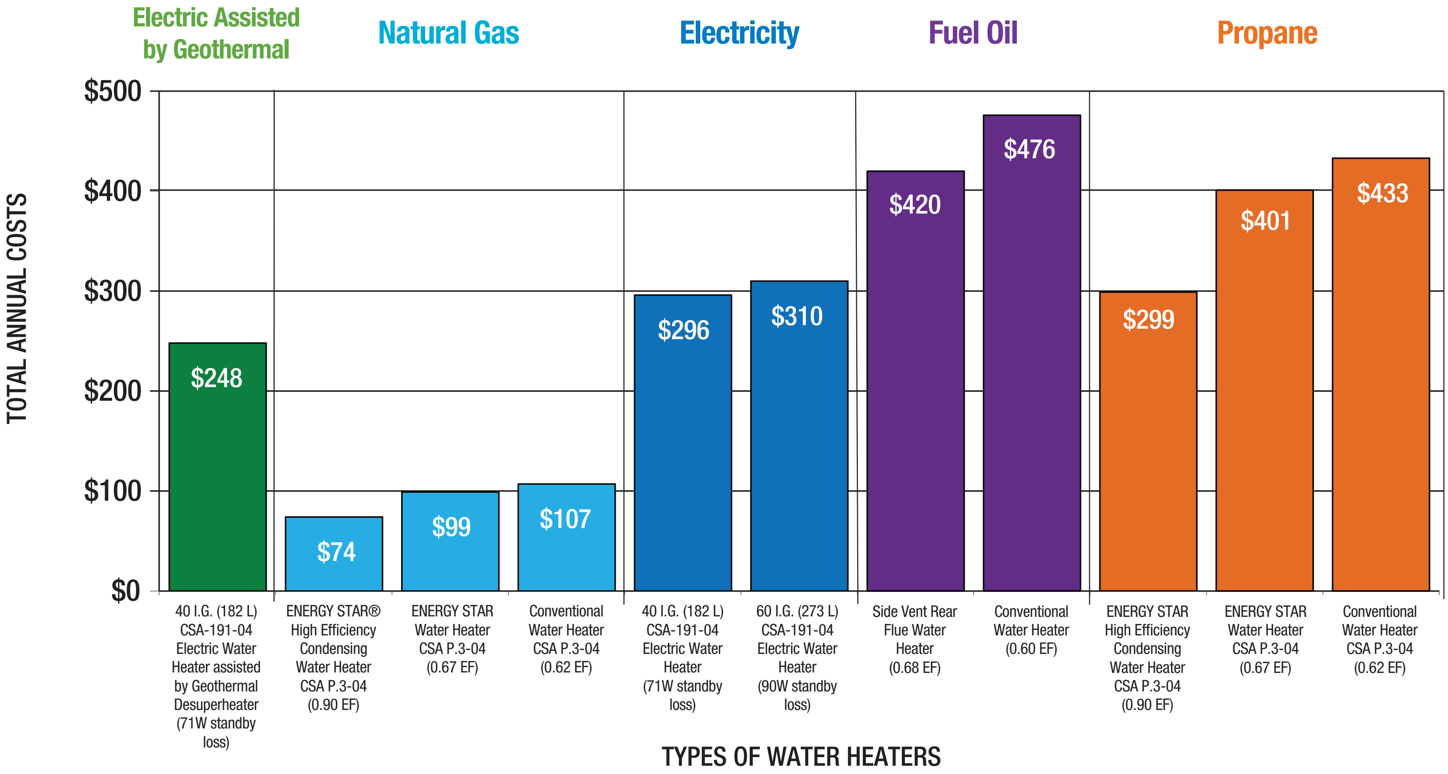
Wondering about your energy options for water heating?

The chart below shows an example of water heating costs that are based on an average single family residence, at rates in effect November 1, 2017.

1. Consult the charts to identify the costs of your current water heating system.
2. Review the annual energy costs of other systems to see how your costs compare.
3. Consult the accompanying notes on pages 2 and 3 for guidance if you are thinking of switching water heating systems or building a new home.
4. Visit **hydro.mb.ca/water** and use the online calculator to get a customized estimate for your specific home's annual and total lifetime water heating costs based on different water heating systems and energy sources.

Annual Water Heating Costs

(Based on average annual hot water usage of 2.4 people per household)



Energy rates

as of November 1, 2017.

Natural gas:	**$0.2293**/cubic metre
Electricity:	**$0.08196**/kilowatt-hour
Fuel oil:	**$1.023**/litre
Propane:	**$0.638**/litre

Water heating annual costs shown in the chart above are based on "point-in-time" prices as noted.

The annual water heating costs presented in the chart exclude the cost of converting to a different heating system, which may be significant.

See page 3 if you are thinking of changing your water heating system.

Depending on your supplier, propane and fuel oil prices can fluctuate on a daily basis.

Manitoba Hydro

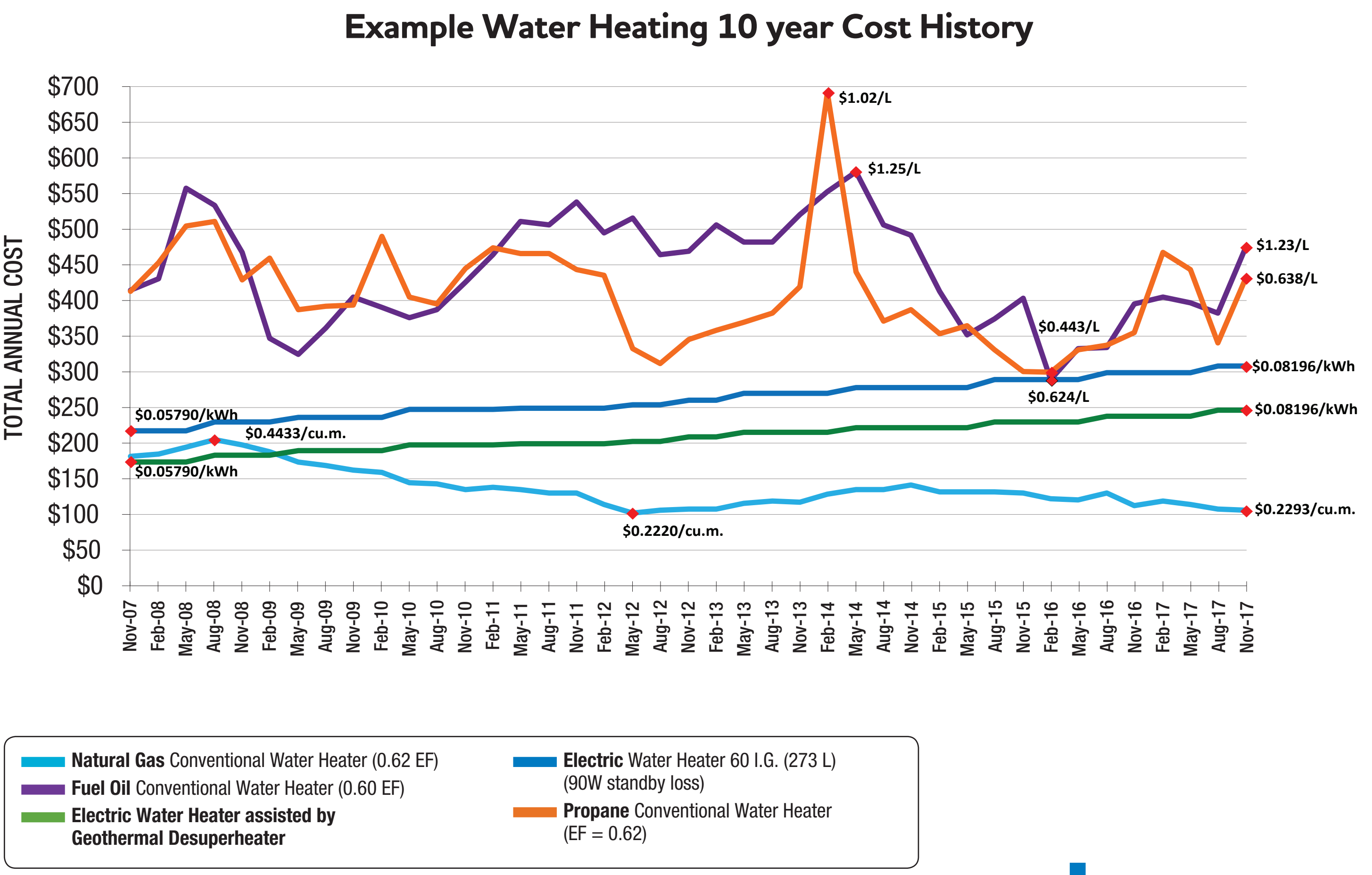
Annual cost estimates

The water heating costs shown in the chart are based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day. Your water heating costs may differ due to varying shower, bathing, clothing and dish washing usage patterns related to your lifestyle. If you think your hot water usage is higher or lower than this average, please factor up or down the operating costs of the various water heaters shown in the chart. The costs shown are relative, illustrative and for general comparison purposes only.

The chart on the first page presents annual costs as if all energy rates remained fixed for the coming year at the rates in effect on November 1, 2017.

Your actual annual energy costs will vary. Natural gas rates change four times per year, electricity rates typically change on an annual basis and depending on your supplier, propane and oil rates can change daily. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0831 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2293 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

The chart below shows a 10 year annual operating cost history trend of various energy sources and water heating systems. The chart also shows the minimum and maximum energy prices for a given point in time by energy source over the 10 year period. The energy prices shown are provided as reference points to show the relationship between the energy price at a given point in time and the annual operating costs of a specific heating system.


Example Water Heating 10 year Cost History

Key points if you are thinking of changing heating systems

Is it economically feasible?

Note that the costs of switching to another water heating system to heat your water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry an electrical water heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the water heating equipment required for your home. If you don't have space in your existing electrical panel for the new circuit breaker you will require an electrician to install an electrical sub panel.

Flue gas venting

When gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard.

If you replace your old conventional or mid-efficiency gas furnace with a high efficiency model you may need to modify the existing chimney to ensure continued proper venting of flue gases from your existing conventional gas water heater. Consult with a licensed and reputable contractor to determine if upgrades to your chimney are required. If chimney upgrades are required and they are deemed to be quite costly, consider installing a power-vented gas water heater or an electric water heater. To ensure you are getting best value when looking at a new water heater, consider the total lifetime cost, which is the cost to buy, install and operate the water heater over its useful life.

Calculate your payback

Determining how many years it will take for a new water heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual water heating cost of the new water heating system you are considering from the annual water heating cost of your current system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated annual savings.

The result is the number of years it will take for the new heating system to pay for itself.

Explanation of technical information in the charts

- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50°C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 watts for a 60 gallon.

ENERGY RATES — in effect November 1, 2017

	Commodity charge	Heating value
Natural gas	$0.2293/cubic metre	35,310 Btu/cubic metre
Electricity	$0.08196/kilowatt-hour	3,413 Btu/kilowatt-hour
Fuel oil	$1.023/litre	36,500 Btu/litre
Propane	$0.638/litre	24,200 Btu/litre

- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.0831 per cubic metre. Primary Gas currently comprises 92 per cent of the gas supplied (supplemental gas is 8 per cent.)
- Taxes are not included in the examples.

Available in accessible formats upon request.

Manitoba Hydro

REFERENCE:

Appendix 7.2 15 Year DSM Plan Page 14; 2012/13 GRA Appendix 26; Manitoba Hydro October 6, 2016 presentation to DSM stakeholder group

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update Manitoba Hydro's 2016 fuel switching analysis referenced at and shown in the presentation from the October 6, 2016 DSM Stakeholder meeting.

b) Please outline Manitoba Hydro's current policy and strategy relative to Fuel Choice Initiatives for the test years.

c) Similar to NFAT PUB Exhibit 58-2 pp. 92 and 93, please provide the annual residential space and water heating cost comparison between electric and gas using:

  i. High efficiency gas furnace consumption, standard efficiency gas and electric water heater consumption

  ii. Actual electric and gas billed rates (from 2002 to latest available)

  iii. Forecast electric rate increases equal to those proposed in IFF16

  iv. Two separate forecast gas rate curves:

    - CGM16 gas assumed rate increases with commodity portion of forecast gas rate assumed to follow a relevant and recent price forecast, such as AECO-NIT future prices.
    - Same as above but also accounting for the impact of the federal carbon pricing backstop system recently proposed by the Government of Canada (i.e.: rates for fuels are subject a levy equivalent to $10 per tonne of CO2e in 2018 and increase by $10 per tonne annually to $50 per tonne in 2022).

RATIONALE FOR QUESTION:

To better understand Manitoba Hydro's test year Fuel Choice strategy, which was recommended to continue by the Board in its NFAT report. To visualize customer impacts and to understand customers' options with respect to fuel switching and a potential residential electric heat rate design.

RESPONSE:

a) Manitoba Hydro's 2016 fuel switching analysis referenced at and shown in the presentation from the October 6, 2016 DSM Stakeholder meeting is the most up to date analysis at this time.

b) Manitoba Hydro is a provider of both electricity and natural gas and therefore, a customer's heating fuel choice should be made by the customer. However, recognizing that heating costs are a significant portion of a customer's annual energy bill, Manitoba Hydro, through the fuel choice initiative, provides educational information and innovative financing to assist customers in making an informed decision. The primary objective of the fuel choice initiative is to ensure customers understand the costs (both annual operating costs and total lifetime costs) of various energy sources and heating equipment so that they can make the choice that best meets their specific needs.

The fuel choice initiative takes a multi-faceted approach recognizing there are several stakeholders involved in or influencing the customer's fuel choice decision. The initiative targets homeowners, heating contractors, homebuilders, land developers and Realtors.

Customers and stakeholders are provided heating education information through:

- Manitoba Hydro's website, which includes tools such as videos, graphs and a heating cost calculator that allows customers to easily compare the costs of various energy sources and heating systems
- social media advertisements
- energy bill inserts
- newspaper advertisements
- magazine advertisements in lifestyle and renovation magazines
- billboards in new home sub-divisions in gas available areas of rural Manitoba
- brochures that are distributed to heating contractors, land developers, Realtors and at Manitoba Hydro's Customer Service Centres

Information sessions are also held annually with heating contractors, homebuilders, land developers and Realtors to increase understanding of heating costs in Manitoba, including what cost implications there are when selecting a specific energy source.

To aid in offsetting the capital cost of a new heating system, Manitoba Hydro offers two convenient on-bill financing programs; the Power Smart Residential Loan and Power Smart PAYS Financing. In many circumstances the customer's average monthly energy bill savings from choosing the natural gas system over an electric system offset the monthly finance fee. Marketing materials speak to the availability and benefits of these offerings.

In addition, where a natural gas service extension request is received from a large commercial customer, Manitoba Hydro works to leverage the larger commercial customer project to extend service to smaller customers along the way.

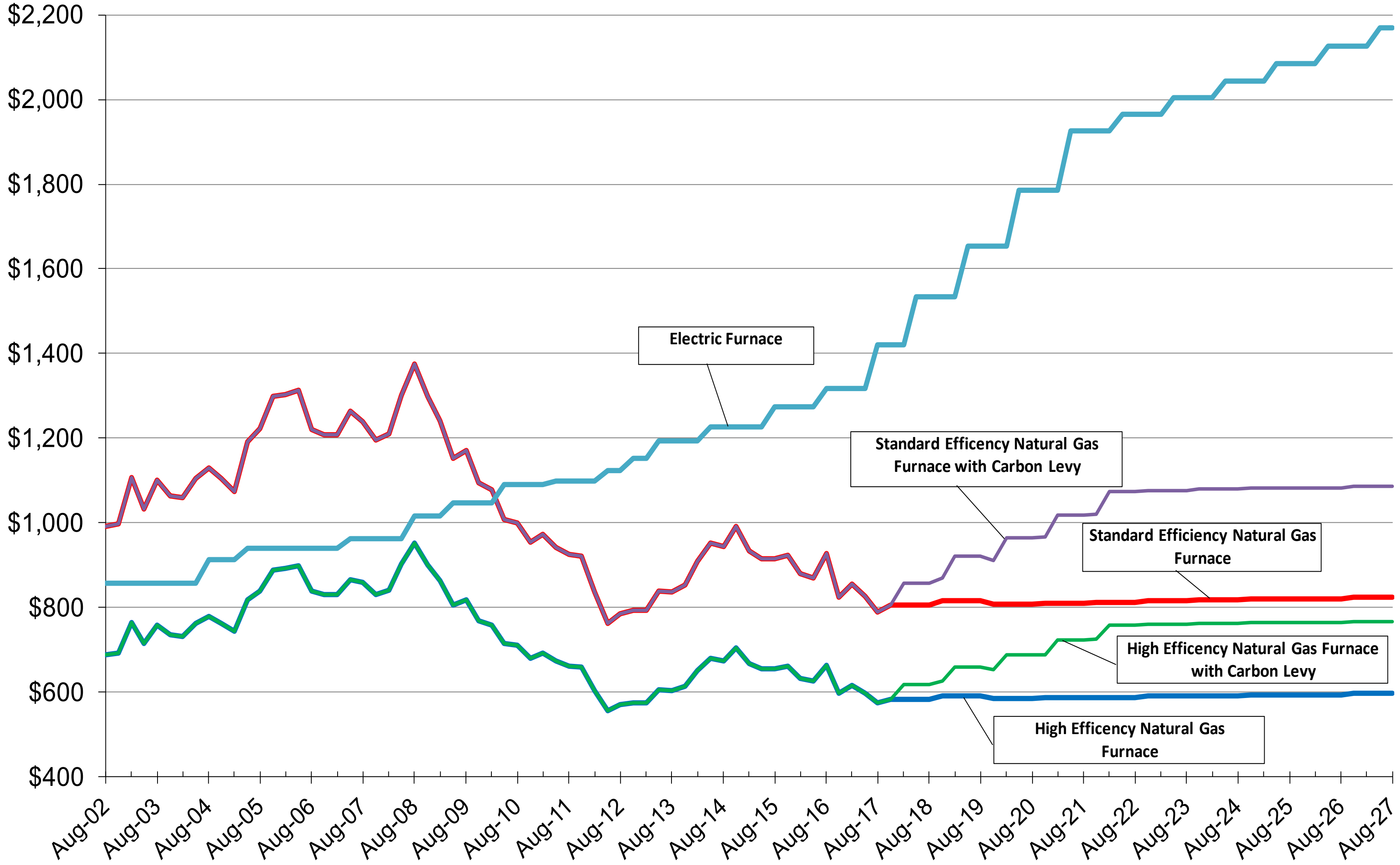
c) Manitoba Hydro has reproduced the PUB's graph below which provides annual residential space and water heating cost comparisons between natural gas and electricity.

Assumptions:

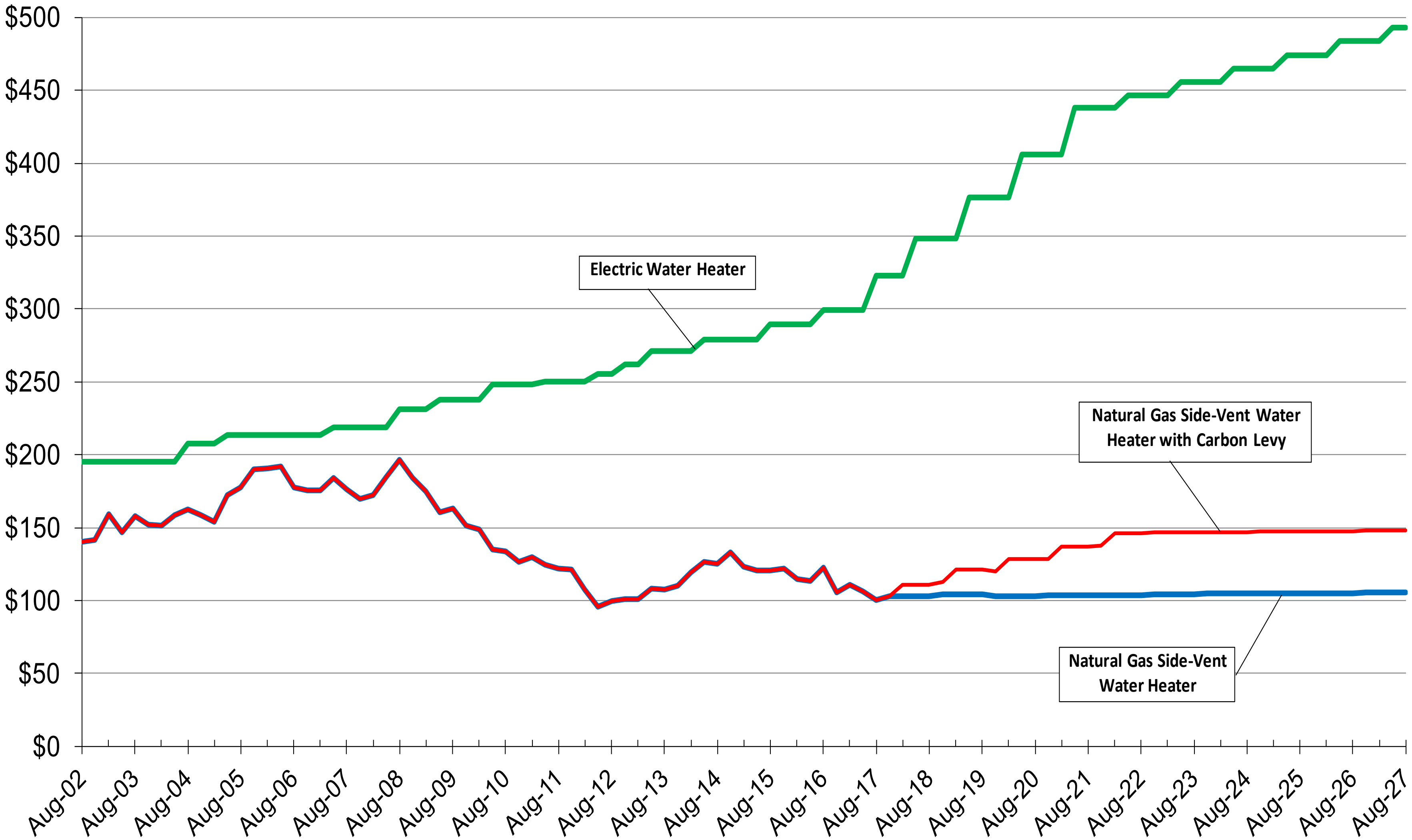
- The natural gas high efficiency furnace has an efficiency rating of 92% and an annual energy consumption of 1 742 cubic metres, the standard efficiency furnace has an efficiency rating of 60% and an annual energy consumption of 2 675 cubic metres. The annual energy consumption of the electric furnace is 16 605 kWh.
- The electric water heater is 60 gallons with a stand-by loss of 90 watts and an annual energy consumption of 3 777 kWh.
- The natural gas side-vent water heater is 50 gallons with an energy factor rating of 0.67 and an annual energy consumption of 431 cubic metres.
- Actual electric billed rates were used from August 1, 2002 until July 31, 2017.
- Forecasted electric rates were used from August 1, 2017 going forward and reflect the forecast rates included in MH16.
- Actual natural gas billed rates were used from August 1, 2002 up to October 31, 2017.

- Forecasted natural gas rates were used from November 1, 2017 forward. The non-commodity portion of the forecasted gas rates is based on CGM16. The commodity portion of natural gas rates is based upon July 28, 2017 futures market prices.
- The cost comparisons that include carbon pricing are based on the Government of Canada's $10 per tonne of CO_2e in 2018 which increases by $10 per tonne annually to $50 per tonne in 2022.

Space Heating Cost Comparison



Water Heating Cost Comparison



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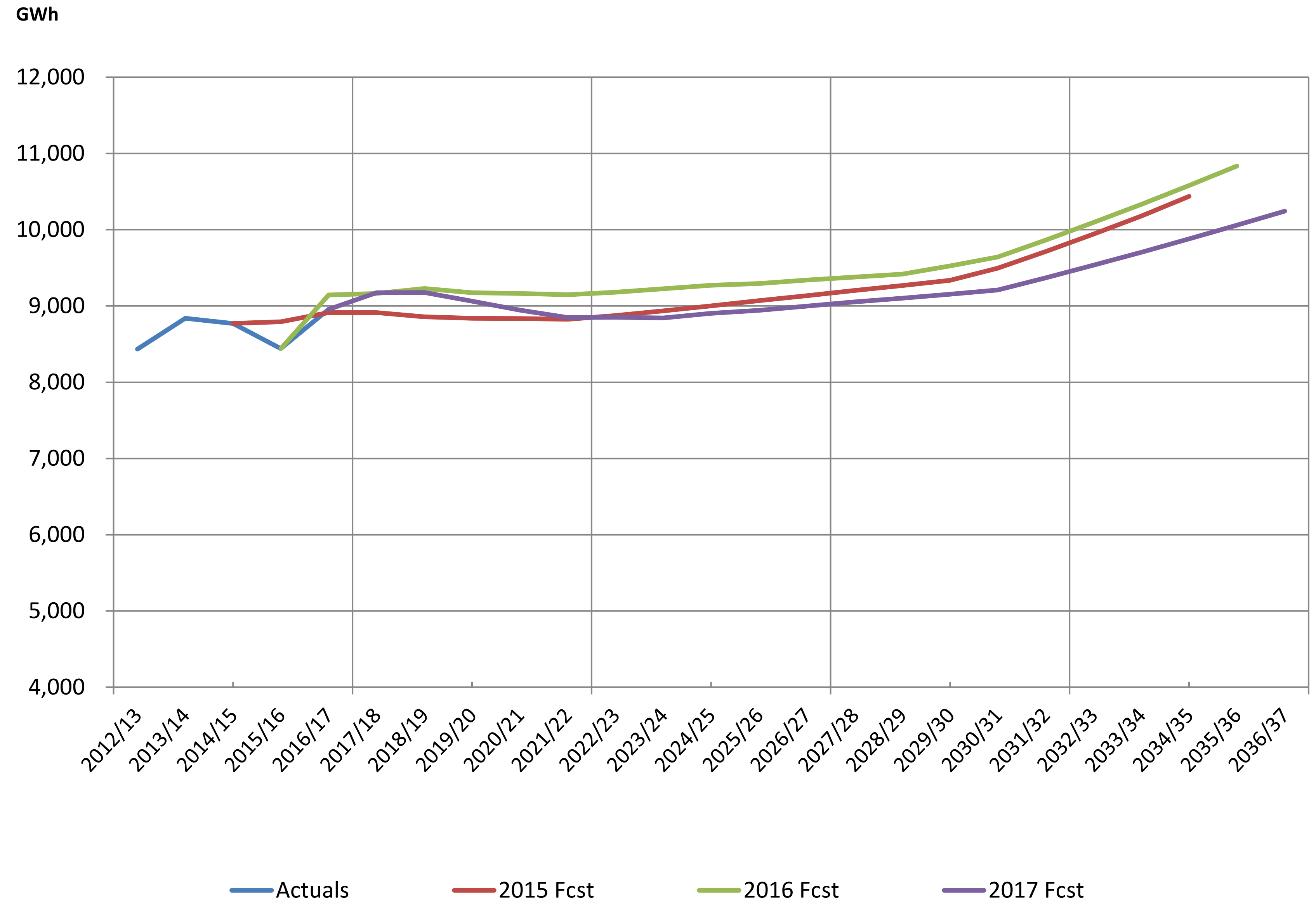
General Service Mass Market Net of DSM



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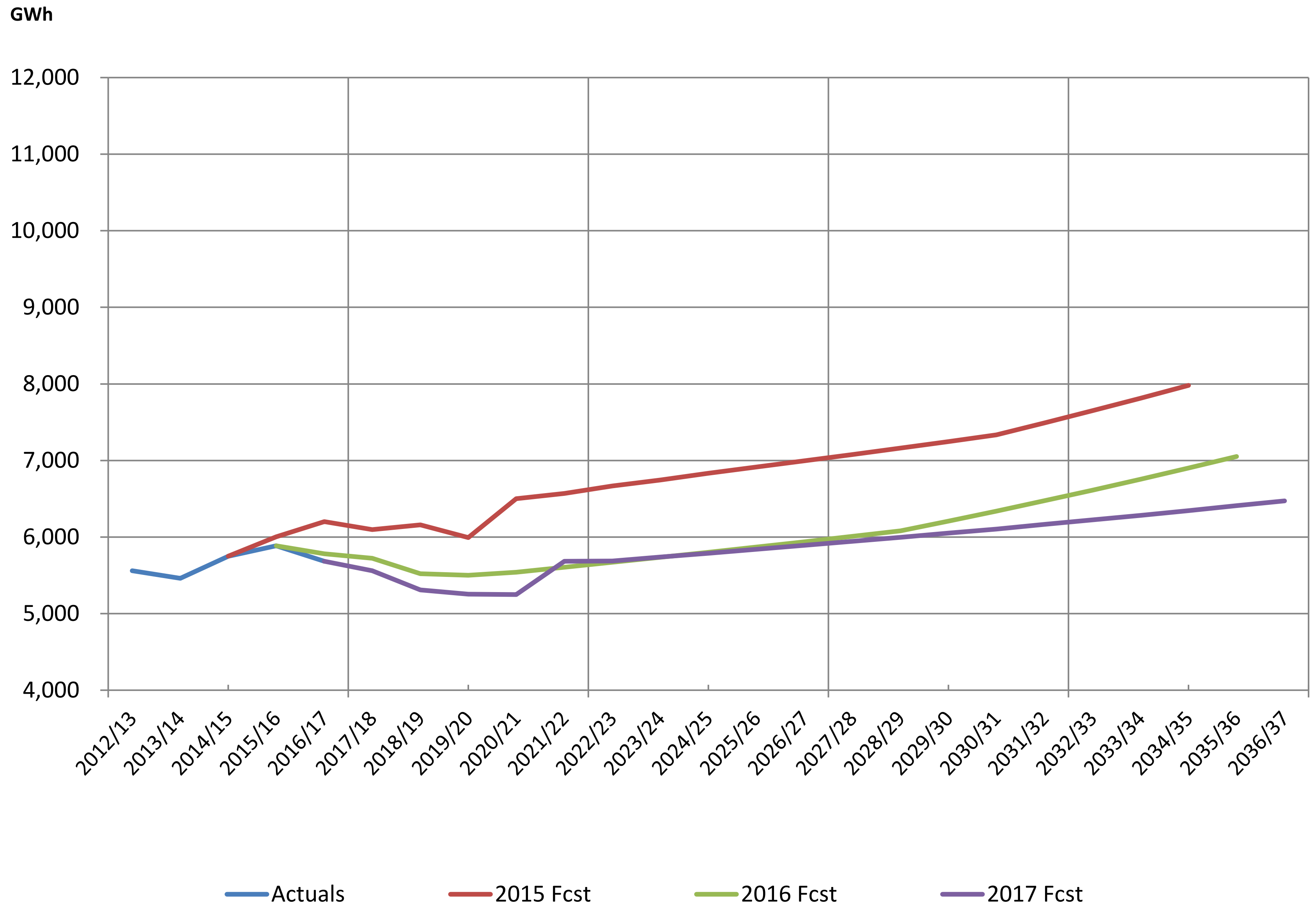
General Service Top Consumers Net of DSM

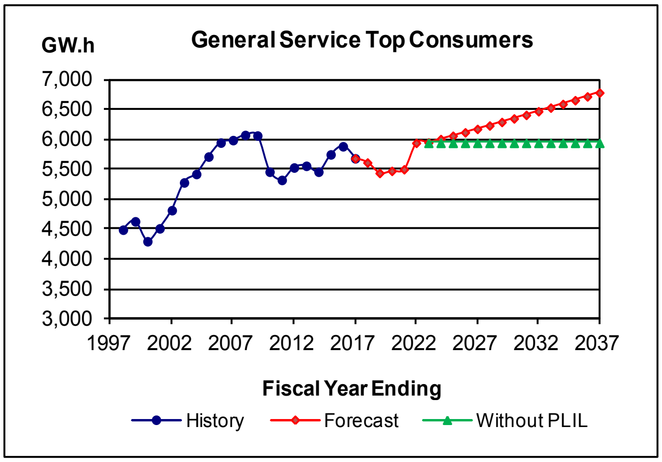


General Service Top Consumers

General Service Top Consumers represent the top energy consuming operations in Manitoba accounting for 25% of all General Consumers Sales. GS Top Consumers include 10 distinct companies that count as 26 customers in the Primary Metals, Chemicals, Petrol/Oil/Natural Gas and Pulp/Paper sectors.

GS Top Consumers increased 84 GWh (1.7%) per year over the past 20 years and increased 10 GWh per year (0.2%) over the past 10 years. The decrease was due to the economic downturn experienced from 2008 to 2011 and the loss of one Top Consumer. The historical growth rates also reflect the shift of the seven smallest Top Consumers to the GS Mass Market Sector, totaling 404 GWh in 2015/16. These were moved because their usage patterns more closely mimic those of GS Mass Market sector.

Figure 8 - General Service Top Consumers



The Top Consumers sector is now forecast to grow an average of 49 GWh (0.8%) per year for the next 10 years and an average of 55 GWh (0.9%) per year for the next 20 years. Short term reductions are expected in the Primary Metals sector. These are offset by increases expected in the Petro/Oil/Natural Gas sector.

Table 16 - General Service Top Consumers

GENERAL SERVICE TOP CONSUMERS (GWh) HISTORICAL/FORECAST WITH PLIL					
Fiscal Year	Sales	Fiscal Year	Individual	PLIL	Total
1997/98	4,493	2017/18	5,615	0	5,615
1998/99	4,632	2018/19	5,440	0	5,440
1999/00	4,299	2019/20	5,475	0	5,475
2000/01	4,515	2020/21	5,502	0	5,502
2001/02	4,818	2021/22	5,943	0	5,943
2002/03	5,282	2022/23	5,943	8	5,951
2003/04	5,423	2023/24	5,943	64	6,007
2004/05	5,714	2024/25	5,943	119	6,062
2005/06	5,948	2025/26	5,943	176	6,119
2006/07	5,989	2026/27	5,943	233	6,176
2007/08	6,075	2027/28	5,943	290	6,233
2008/09	6,065	2028/29	5,943	349	6,292
2009/10	5,461	2029/30	5,943	408	6,351
2010/11	5,324	2030/31	5,943	467	6,410
2011/12	5,531	2031/32	5,943	528	6,471
2012/13	5,560	2032/33	5,943	589	6,532
2013/14	5,461	2033/34	5,943	650	6,593
2014/15	5,750	2034/35	5,943	713	6,656
2015/16	5,886	2035/36	5,943	776	6,719
2016/17	5,685	2036/37	5,943	840	6,783

generating resources currently available within Manitoba and imports from neighboring U.S. utilities, as discussed in Sections 7.4 to 7.6. Manitoba Hydro also engages in the sale of electricity to neighbouring markets, which serves to reduce the revenue required from Manitoba customers.

7.1 ELECTRIC LOAD FORECAST SUMMARY

The Electric Load Forecast provides a long term projection of future electricity demand in Manitoba with a forecast provided for both energy and capacity requirements. The load forecast is reviewed and updated on an annual basis, with the 2016 Electric Load Forecast having been prepared in June 2016.

Given the timing of this Application, it was appropriate to adjust the 2016 Electric Load Forecast in order to reflect the most current information (including nine months of actual load for 2016/17) and to reflect forecasting methodology improvements that were being developed for the next Electric Load Forecast. The load forecast adjustments were based on a preliminary updated population forecast and also considered enhancements planned for the econometric forecast model. In addition, Manitoba Hydro has adopted a more conservative approach in forecasting Potential Large Industrial Loads in the Top Consumer sector, and that direction was considered in making the adjustments to the 2016 Electric Load Forecast. Given energy not sold to Large Industrial Loads is sold on the opportunity market at comparable forecast pricing, there is minimal impact from this change on forecast financial results.

Manitoba Hydro determined that it was not practical to prepare an entirely new electricity load forecast in early 2017. Steps were taken to assess the impact of the changes discussed above, and then apply a high level adjustment to the 2016 Electric Load Forecast.

An assessment was made of the estimated impact of these changes in assumptions and methodology to the load in the 20th year of the 2016 forecast. The estimated impact in the 20th year of the forecast suggested an overall net reduction in annual load equivalent to that determined under the 24th percentile probability point of the 2016 Electric Load Forecast. The 24th percentile probability point is derived from the load

GSL Energy Rates (cents/kWh) - MH16U+I

Fiscal Year Ending	GSL 0-30kV	GSL 30kV-100kV	GSL >100kV	Rate Increase
2018	*3.709*	*3.448*	*3.342*	
2019	4.002	3.720	3.606	7.90%
2020	4.318	4.014	3.891	7.90%
2021	4.659	4.331	4.198	7.90%
2022	5.027	4.674	4.530	7.90%
2023	5.425	5.043	4.888	7.90%
2024	5.853	5.441	5.274	7.90%
2025	6.119	5.688	5.513	4.54%
2026	6.241	5.802	5.624	2%

Source: Appendix 9.3 p.11

PUB Advisor Calculations

REFERENCE:

Coalition/MH I-45a; 2015/16 GRA PUB/MH I-57

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please add two columns to the table in Coalition/MH I-45a: 2013 Forecast and 2013 Forecast with Update reflecting the additional pipeline load contemplated at the NFAT (as seen in the response to 2015/16 GRA PUB/MH I-57).

b) Please identify the specific pipeline loads that are forecast along with their annual energy and capacity requirements.

RATIONALE FOR QUESTION:

RESPONSE:

Public disclosure of the response to this IR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

a) The NFAT 2013 update filed as part of the NFAT proceedings was a scenario update to the 2013 Forecast designed to approximately represent emerging information related to new planned pipeline expansions in the Petroleum sector. This scenario update did not specifically increase customer usage within the pipeline sector forecast; but was approximated by advancing 1700 GWh of the forecast Potential Large Industrial Load ("PLIL") into the first four years of PLIL (Years 4 to 8 of the 20 year forecast period) and continuing with 100 GWh per year PLIL growth thereafter.

The following table presents the forecast for the Pipeline sector under the 2013 Forecast and the 2013 scenario with the adjustment of 1,700 GWh assigned to the pipeline sector. It should be noted that the values in the response to 2015/16 & 2016/17 Electric General Rate Application PUB/MH I-57 were presented at Generation and the 2013 forecast scenario would present a net increase to the Top Consumers overall of 1,300 GWh as compared to the 2013 Load Forecast.

PIPELINE FORECAST COMPARISON

	2013 Forecast	2013 Forecast Pipeline Scenario	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
2013/14	1180	1180	810.4	810.4	810.4	810.4
2014/15	1145	1145	1070	1038	1038	1038
2015/16	1295	1295	1310	1130	1154.2	1154.2
2016/17	1315	1740	1485	1353	1353	1327.9
2017/18	1345	2195	1730	1276	1276	1415
2018/19	1445	2720	1800	1258	1258	1425
2019/20	1345	3045	2005	1252	1252	1460
2020/21	1375	3075	2005	1814	1814	1577
2021/22	1385	3085	2005	1806	1806	2007
2022/23	1395	3095	2005	1827	1827	2007
2023/24	1395	3095	2005	1827	1827	2007
2024/25	1395	3095	2005	1833	1833	2007
2025/26	1395	3095	2005	1835	1835	2007
2026/27	1395	3095	2005	1835	1835	2007
2027/28	1395	3095	2005	1835	1835	2007
2028/29	1395	3095	2005	1835	1835	2007
2029/30	1395	3095	2005	1835	1835	2007
2030/31	1395	3095	2005	1835	1835	2007
2031/32	1395	3095	2005	1835	1835	2007
2032/33	1395	3095	2005	1835	1835	2007
2033/34			2005	1835	1835	2007
2034/35				1835	1835	2007
2035/36					1835	2007
2036/37						2007

b) Only annual energy load is forecasted for each pipeline company. Capacity requirements are not forecasted on an annual basis. Below are the customer specific loads as forecast in the 2017 Electric Load Forecast.

	[redacted]
2017/18	[redacted]
2018/19	[redacted]
2019/20	[redacted]
2020/21	[redacted]
2021/22	[redacted]
2022/23	[redacted]
2023/24	[redacted]
2024/25	[redacted]
2025/26	[redacted]
2026/27	[redacted]
2027/28	[redacted]
2028/29	[redacted]
2029/30	[redacted]
2030/31	[redacted]
2031/32	[redacted]
2032/33	[redacted]
2033/34	[redacted]
2034/35	[redacted]
2035/36	[redacted]
2036/37	[redacted]

Contract Limit (MV.A.)	[redacted]
2016/17 Peak	[redacted]

REFERENCE:

Tab 7, Appendix 7.1, Page 22

PREAMBLE TO IR (IF ANY):

Factors to predict electricity demand for Top Customers include prices and GDP.

QUESTION:

a) Has Manitoba Hydro investigated how Top Customers will respond to increases in rates on the order of 6% above inflation, including the possibility that they might relocate outside the province as Manitoba Hydro rates become less favourable? Please support this answer with any data or research relied upon.

b) Has Manitoba Hydro investigated how other GS Customers will respond to increases in rates on the order of 6% above inflation, including the possibility that they might relocate outside the province as Manitoba Hydro rates become less favourable? Please support this answer with any data or research relied upon.

RATIONALE FOR QUESTION:

RESPONSE:

Responses to a) and b)

Electricity prices are but one factor that Top Consumer customers take into consideration in planning their business operations in Manitoba. All econometric analyses undertaken in the development of the 2017 Forecast are based upon the proposed electricity rate projections of 7.9% for five years presented under IFF16. However, as noted in the reference above, for the first five years of the forecast, Top Consumers are forecast individually based upon information solicited from each customer with respect to their operating plans and projections for the future.

It is expected that the short-term plans of Top Consumers incorporated within the 2017 Forecast (as found in PUB MFR 65 Updated) will not specifically reflect customers' plans under the electricity rate projections proposed under IFF16 as that information was not public at the time of this data collection

Since filing the 2017/18 & 2018/19 Electric General Rate Application, with proposed rate increases of 7.9% for 5 years, Manitoba Hydro has met with the Manitoba Industrial Power Users Group and individually with representatives of a number of the Top Consumers sector companies to explain Manitoba Hydro's need for these rate increases and to discuss the potential impact on operations in Manitoba. In addition, detailed internal discussions were held with Manitoba Hydro Account Representatives representing these customers. These discussions were assessed from a qualitative perspective recognizing that increasing electricity prices are not the only determinate on whether or not a business continues to operate in Manitoba and that Manitoba Hydro cannot specifically predict how individual customers will respond or to what degree under the proposed rate increases.

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Figure 12 compares historical weather adjusted gross firm energy to different forecast vintages of gross firm energy. Comparing the 2011, 2014, and 2015 forecast values of the gross firm energy with the weather adjusted actual gross firm energy, this figure demonstrates that the forecasted load was greater than the actual load for all years. In particular, the 2011 forecast has the highest estimated deviations, followed by the 2015 and the 2014 forecasts. Only one historical data point exists for the 2016 forecast.

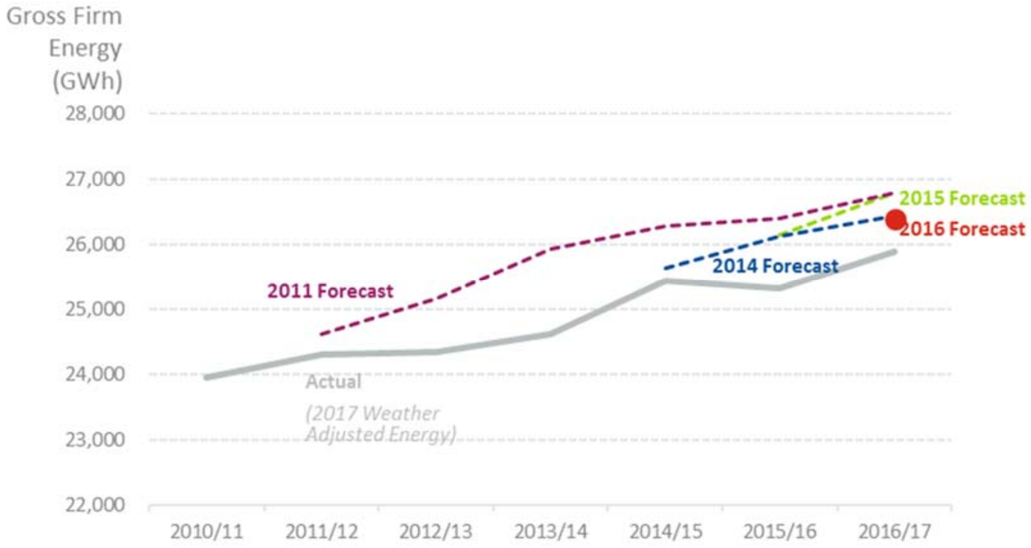


Figure 12: Comparison of Historical Weather Adjusted Gross Firm Energy (GWh) with Multiple Forecast Vintages of Gross Firm Energy

Figure 13 displays the estimated residential sales load values from the various forecasts conducted by MH. The 2011 forecast has consistently higher values than the actual historical adjusted values. The 2015 forecast also estimated higher values than those in 2017 in the later years shown in the figure. The figure shows that the Residential forecast created in 2014 estimated lower load than actual for the first two years of the forecast.

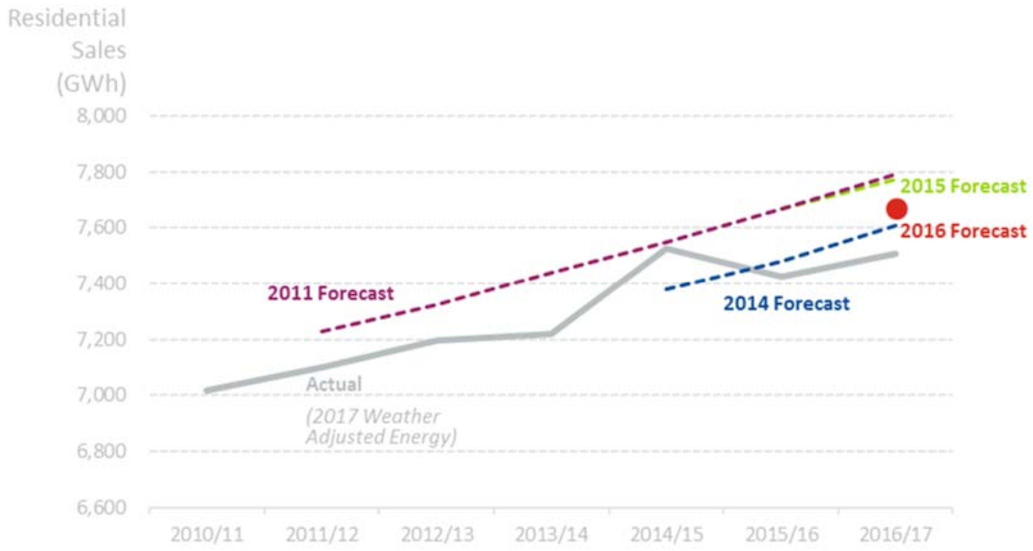


Figure 13: Comparison of Historical Weather Adjusted Residential Sales (GWh) with Multiple Forecast Vintages of Residential Sales

Figure 14 shows the estimated GSMM load values from the different forecast years. Overall, each forecast estimated load values that were higher than actual adjusted energy values. The only exception was the 2016/17 value from the 2015 forecast, which was slightly lower than the actual forecast.

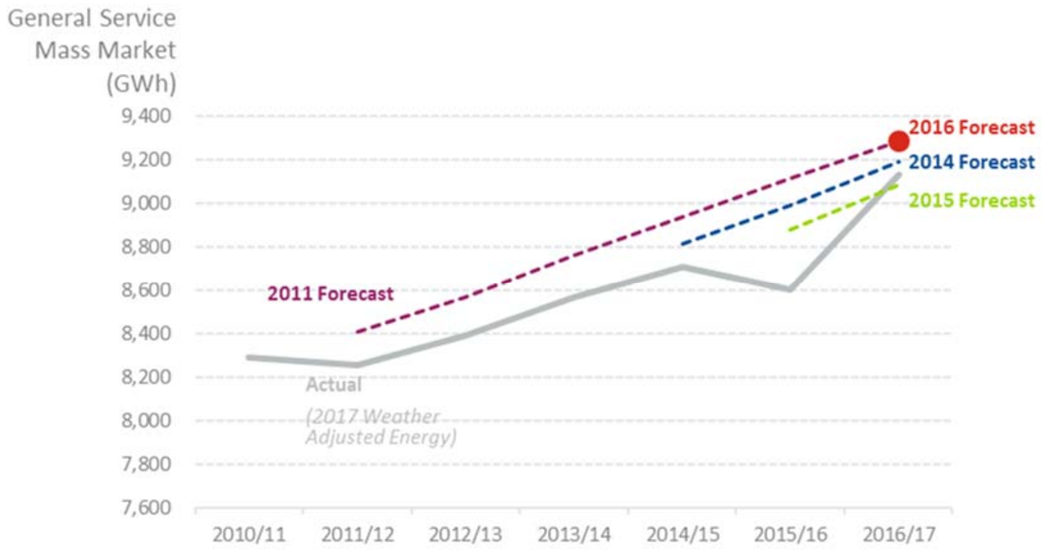


Figure 14: Comparison of Historical Weather Adjusted General Service Mass Market Sales (GWh) with Multiple Forecast Vintages of GSMM Sales

Figure 15 displays the estimated GS top consumer load from different MH forecasts. While all the previous forecasts have load values that were higher than actual historical consumption, there is significant variability in different years' forecasts from 2015/2016. While the 2015 forecast value is lower than both the 2011 and 2014 forecast value in 2015/16, it exceeds both the 2011 and 2014 values by 2016/17. The 2014 forecast value rises to more or less equal the 2011 forecast value in 2015/16 but falls below the 2014 forecast again by 2016/17.

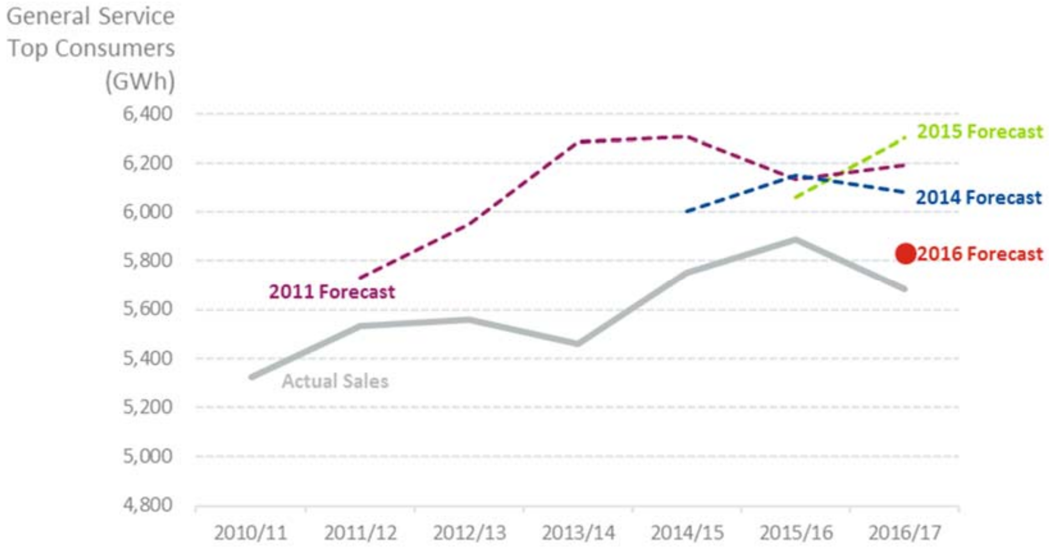


Figure 15: Comparison of Actual General Service Top Consumers Sales (GWh) with Multiple Forecast Vintages of Top Consumers Sales

REFERENCE:

PUB MFR 65 – 2017 Load Forecast Table 35

PREAMBLE TO IR (IF ANY):

QUESTION:

Please tabulate the forecast accuracies for forecasts made 1 year, 2 years, and 3 years prior in a similar format as Table 35 but provide separately for Residential, General Service Mass Market, and Top Consumer loads. Please also provide graphs showing the forecast accuracy similar to Figure 22. The response may be limited to the previous 10 years of forecasts.

RATIONALE FOR QUESTION:

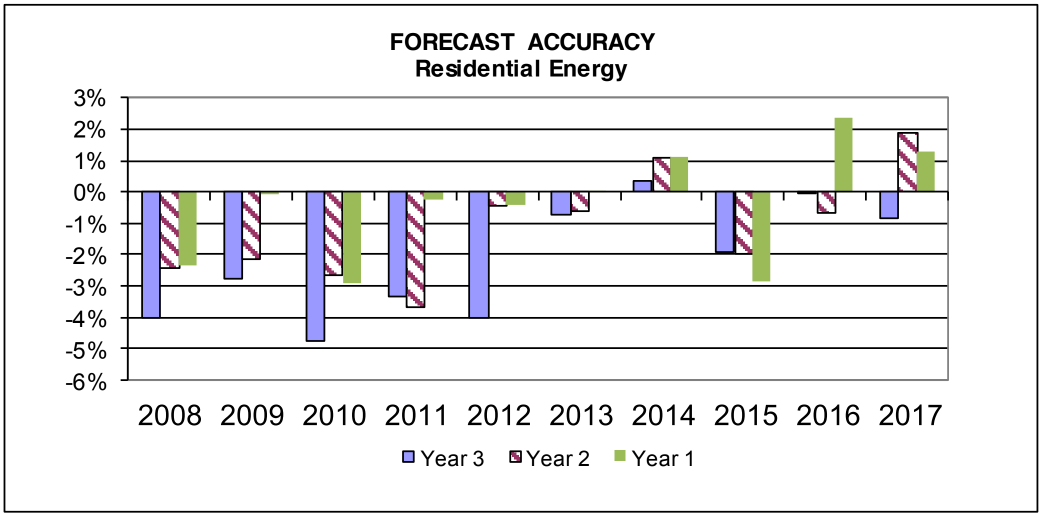
To quantify the load forecast accuracy by customer segment

RESPONSE:

Please see the tables below:

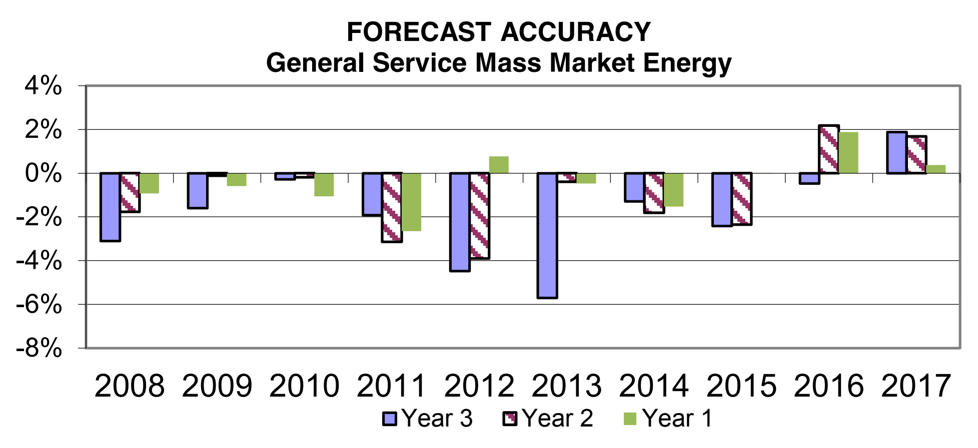
Forecast Accuracy
Residential Energy (GW.h)

Fiscal Year	Actual Residential Energy	Forecast Prepared 1 Year Previous	W.A Residential Energy	1 Year Percent Accuracy	Forecast Prepared 2 Years Previous	W.A Residential Energy	2 Year Percent Accuracy	Forecast Prepared 3 Years Previous	W.A Residential Energy	3 Year Percent Accuracy
2007/08	6,736	6,426	6,582	-2.4%	6,499	6,658	-2.4%	6,394	6,661	-4.0%
2008/09	6,847	6,640	6,642	.0%	6,475	6,614	-2.1%	6,532	6,717	-2.8%
2009/10	6,786	6,708	6,907	-2.9%	6,683	6,865	-2.6%	6,511	6,835	-4.7%
2010/11	6,952	7,021	7,036	-.2%	6,757	7,015	-3.7%	6,738	6,972	-3.4%
2011/12	6,818	7,089	7,119	-.4%	7,089	7,120	-.4%	6,812	7,098	-4.0%
2012/13	7,223	7,206	7,204	.0%	7,166	7,210	-.6%	7,160	7,212	-.7%
2013/14	7,767	7,319	7,240	1.1%	7,303	7,224	1.1%	7,255	7,231	.3%
2014/15	7,658	7,346	7,560	-2.8%	7,404	7,550	-1.9%	7,392	7,535	-1.9%
2015/16	7,074	7,633	7,455	2.4%	7,412	7,460	-.6%	7,448	7,450	.0%
2016/17	7,158	7,616	7,519	1.3%	7,682	7,537	1.9%	7,481	7,543	-.8%



Forecast Accuracy
General Service Mass Market Energy (GW.h)

Fiscal Year	Actual General Service Mass Market Energy	Forecast Prepared 1 Year Previous	W.A General Service Mass Market Energy	1 Year Percent Accuracy	Forecast Prepared 2 Years Previous	W.A General Service Mass Market Energy	2 Year Percent Accuracy	Forecast Prepared 3 Years Previous	W.A General Service Mass Market Energy	3 Year Percent Accuracy
2007/08	8,006	7,834	7,908	-.9%	7,810	7,952	-1.8%	7,707	7,954	-3.1%
2008/09	8,049	7,900	7,947	-.6%	7,912	7,922	-.1%	7,852	7,980	-1.6%
2009/10	7,985	7,988	8,073	-1.1%	8,002	8,017	-.2%	7,970	7,993	-.3%
2010/11	8,258	8,085	8,306	-2.7%	8,032	8,293	-3.1%	8,074	8,232	-1.9%
2011/12	8,162	8,337	8,273	.8%	8,154	8,485	-3.9%	8,093	8,473	-4.5%
2012/13	8,434	8,361	8,401	-.5%	8,369	8,402	-.4%	8,162	8,655	-5.7%
2013/14	8,839	8,455	8,586	-1.5%	8,421	8,577	-1.8%	8,468	8,579	-1.3%
2014/15	8,771	8,728	8,727	.0%	8,520	8,726	-2.4%	8,506	8,717	-2.4%
2015/16	8,442	8,778	8,617	1.9%	8,807	8,620	2.2%	8,577	8,618	-.5%
2016/17	8,956	9,173	9,139	.4%	8,869	8,723	1.7%	8,892	8,728	1.9%



Forecast Accuracy
Top Consumers Energy (GW.h)

Fiscal Year	Actual Top Consumers Energy	Forecast Prepared 1 Year Previous	W.A Top Consumers Energy	1 Year Percent Accuracy	Forecast Prepared 2 Years Previous	W.A Top Consumers Energy	2 Year Percent Accuracy	Forecast Prepared 3 Years Previous	W.A Top Consumers Energy	3 Year Percent Accuracy
2007/08	6,075	6,209	6,091	1.9%	6,236	6,087	2.4%	6,480	6,087	6.4%
2008/09	6,065	6,380	6,102	4.6%	6,672	6,112	9.2%	6,426	6,109	5.2%
2009/10	5,461	5,970	5,458	9.4%	6,799	5,497	23.7%	7,268	5,506	32.0%
2010/11	5,324	5,604	5,321	5.3%	6,203	5,321	16.6%	7,218	5,367	34.5%
2011/12	5,531	5,747	5,528	3.9%	5,919	5,315	11.4%	6,506	5,315	22.4%
2012/13	5,560	5,809	5,557	4.5%	5,955	5,557	7.2%	6,031	5,303	13.7%
2013/14	5,461	5,908	5,461	8.2%	6,185	5,461	13.3%	6,271	5,461	14.8%
2014/15	5,750	5,982	5,750	4.0%	5,997	5,750	4.3%	6,158	5,750	7.1%
2015/16	5,886	6,026	5,886	2.4%	6,094	5,886	3.5%	6,039	5,886	2.6%
2016/17	5,685	5,739	5,685	1.0%	6,171	6,109	1.0%	5,932	6,109	-2.9%

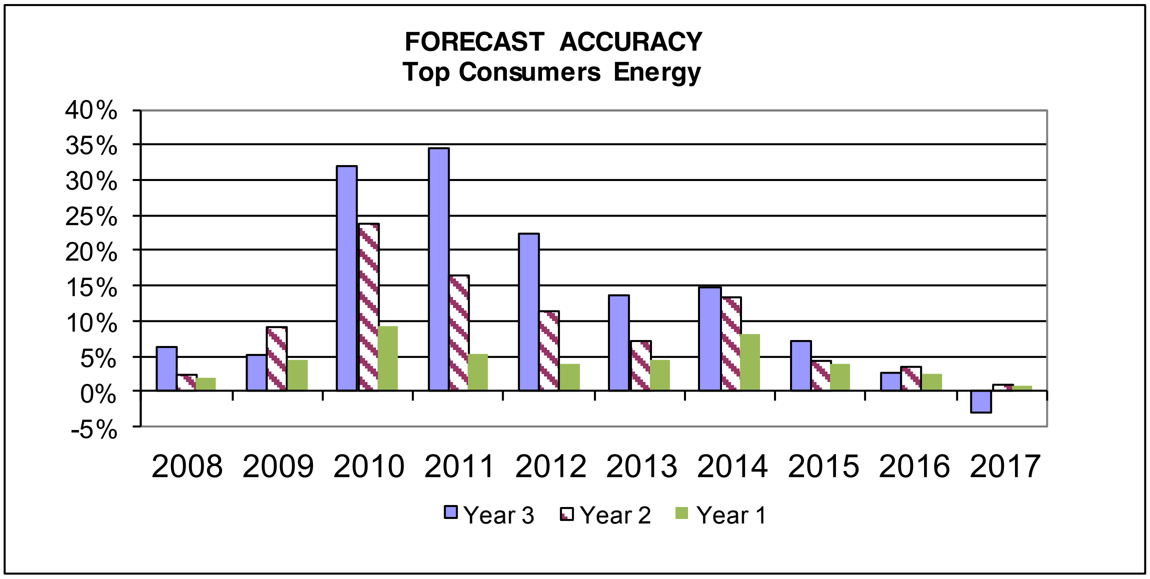


Figure 22 - Energy Accuracy

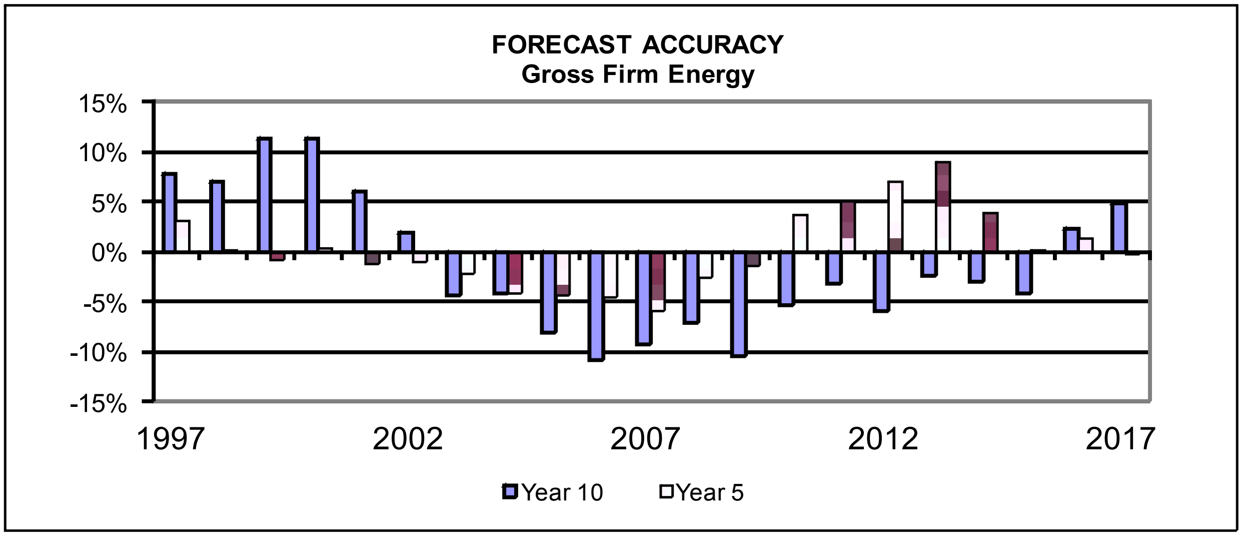


Table 35 - Energy Accuracy

Fiscal Year	Actual Gross Firm Energy	Forecast Prepared 5 Years Previous	W.A. Gross Firm Energy	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	W.A. Gross Firm Energy	10 Year Percent Accuracy
1996/97	19,321	19,395	18,810	3.1%	20,174	18,716	7.8%
1997/98	19,014	19,455	19,429	0.1%	20,661	19,320	6.9%
1998/99	19,273	19,675	19,818	-0.7%	21,919	19,708	11.2%
1999/00	18,971	19,767	19,703	0.3%	21,833	19,629	11.2%
2000/01	20,262	20,018	20,241	-1.1%	21,300	20,103	6.0%
2001/02	20,656	20,783	20,980	-0.9%	21,364	20,979	1.8%
2002/03	22,110	21,395	21,861	-2.1%	20,916	21,868	-4.4%
2003/04	22,069	21,134	22,062	-4.2%	21,191	22,107	-4.1%
2004/05	22,589	21,693	22,664	-4.3%	20,870	22,714	-8.1%
2005/06	22,757	22,216	23,277	-4.6%	20,812	23,346	-10.9%
2006/07	23,464	22,107	23,489	-5.9%	21,395	23,595	-9.3%
2007/08	24,122	23,353	23,962	-2.5%	22,328	24,034	-7.1%
2008/09	24,417	23,926	24,259	-1.4%	21,756	24,320	-10.5%
2009/10	23,412	24,734	23,850	3.7%	22,611	23,892	-5.4%
2010/11	23,892	25,239	24,020	5.1%	23,299	24,071	-3.2%
2011/12	23,605	25,909	24,202	7.1%	22,924	24,376	-6.0%
2012/13	24,750	26,464	24,270	9.0%	23,844	24,433	-2.4%
2013/14	25,625	25,510	24,538	4.0%	23,936	24,696	-3.1%
2014/15	25,505	25,491	25,469	0.1%	24,455	25,508	-4.1%
2015/16	24,665	25,707	25,366	1.3%	25,999	25,405	2.3%
2016/17	25,227	25,902	25,936	-0.1%	26,984	25,747	4.8%

Figure 23 - Peak Accuracy

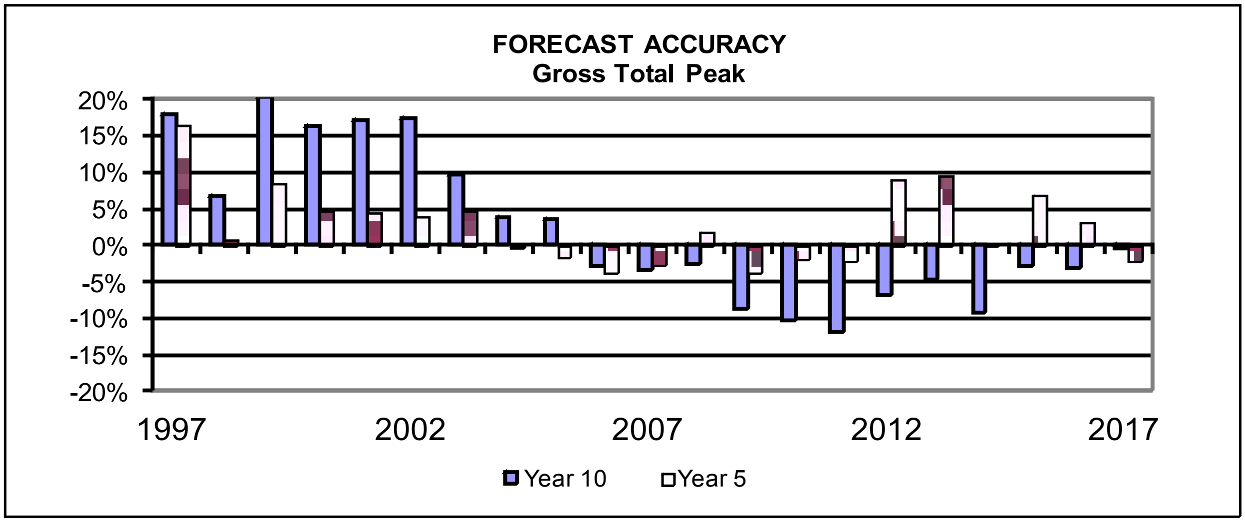


Table 36 - Peak Accuracy

Fiscal Year	Actual Gross Total Peak	Forecast Prepared 5 Years Previous	Normalized Gross Total Peak	5 Year Percent Accuracy	Forecast Prepared 10 Years Previous	Normalized Gross Total Peak	10 Year Percent Accuracy
1996/97	3,444	3,906	3,356	16.4%	3,962	3,356	18.0%
1997/98	3,525	3,768	3,739	0.8%	3,990	3,739	6.7%
1998/99	3,596	3,703	3,413	8.5%	4,108	3,413	20.3%
1999/00	3,555	3,738	3,569	4.7%	4,152	3,569	16.3%
2000/01	3,672	3,758	3,596	4.5%	4,210	3,596	17.1%
2001/02	3,797	3,759	3,619	3.9%	4,251	3,619	17.5%
2002/03	3,948	3,801	3,634	4.6%	3,989	3,634	9.8%
2003/04	3,994	3,833	3,843	-0.3%	3,990	3,843	3.8%
2004/05	4,201	3,817	3,889	-1.8%	4,023	3,889	3.5%
2005/06	4,085	3,860	4,015	-3.9%	3,899	4,015	-2.9%
2006/07	4,208	3,894	4,006	-2.8%	3,868	4,006	-3.5%
2007/08	4,304	4,097	4,029	1.7%	3,927	4,029	-2.5%
2008/09	4,509	4,161	4,327	-3.8%	3,948	4,327	-8.8%
2009/10	4,393	4,371	4,454	-1.9%	3,993	4,454	-10.4%
2010/11	4,286	4,398	4,496	-2.2%	3,959	4,496	-12.0%
2011/12	4,367	4,606	4,228	8.9%	3,942	4,228	-6.8%
2012/13	4,559	4,705	4,296	9.5%	4,098	4,296	-4.6%
2013/14	4,743	4,523	4,522	0.0%	4,106	4,522	-9.2%
2014/15	4,713	4,658	4,363	6.8%	4,233	4,363	-3.0%
2015/16	4,479	4,735	4,588	3.2%	4,451	4,588	-3.0%
2016/17	4,822	4,616	4,726	-2.3%	4,708	4,726	-0.4%

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Demand Side Management Plan

2016/17

SUPPLEMENTAL REPORT:

15 yr (2016 to 2031)

September 2016

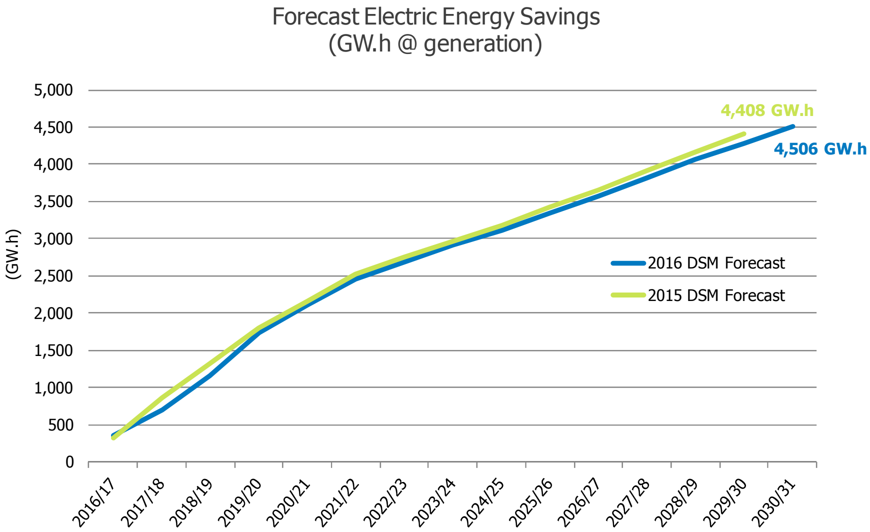
Available in accessible formats upon request

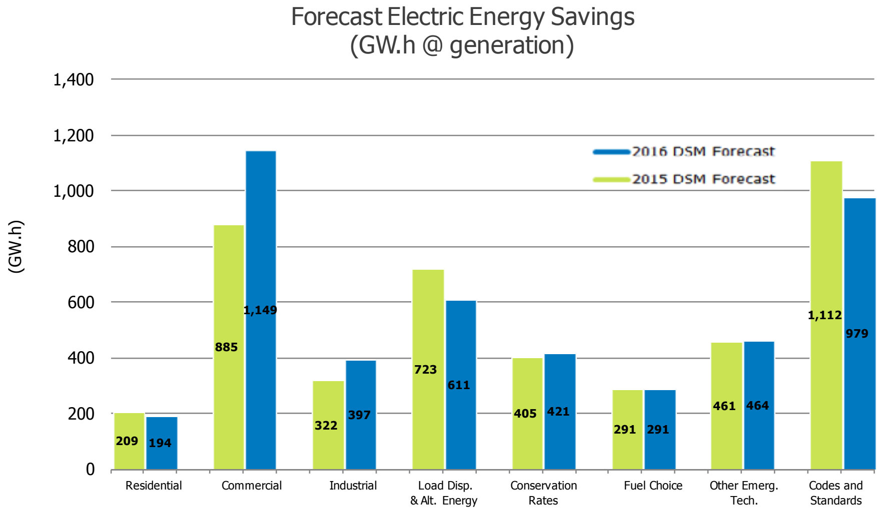
Manitoba Hydro POWER SMART*

Changes from the 2015 Power Smart Plan (Supplemental Report 15 yr)

Electric DSM

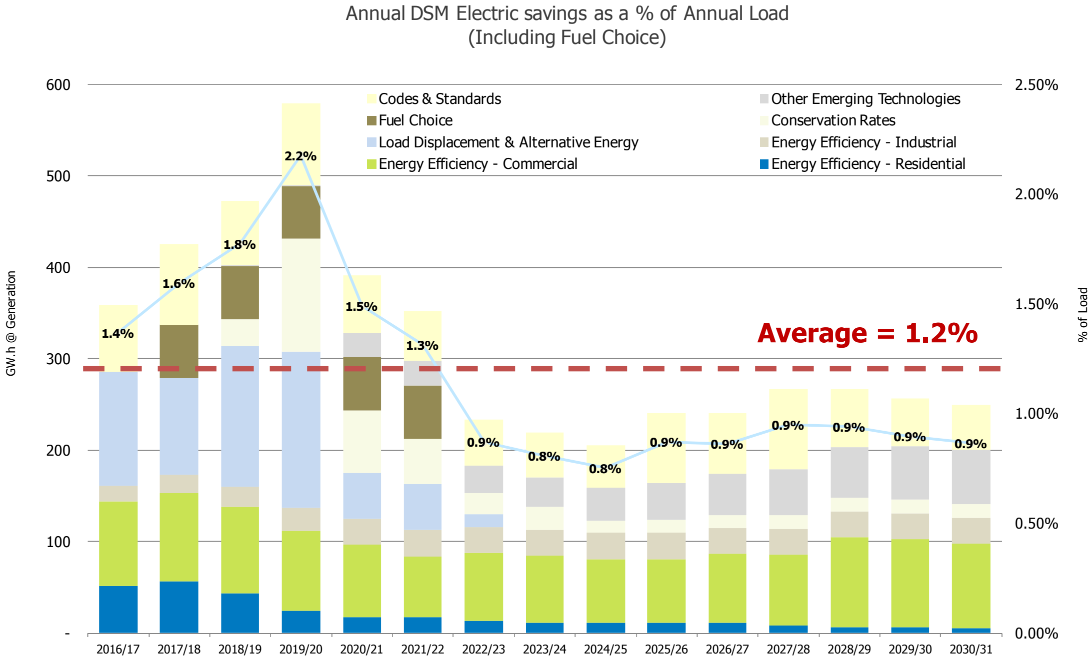
Overall, energy savings are expected to increase by 2.2% from the 2015 DSM forecast. The planned electric energy savings in this plan are approximately 98 GW.h higher than previously forecast in the 2015 Power Smart Plan due to revisions to forecast program savings based on current market information and the inclusion of an additional year at the end of the forecasting period. (Refer to section 1.6 Comparison to 2015 DSM Forecast for detail).



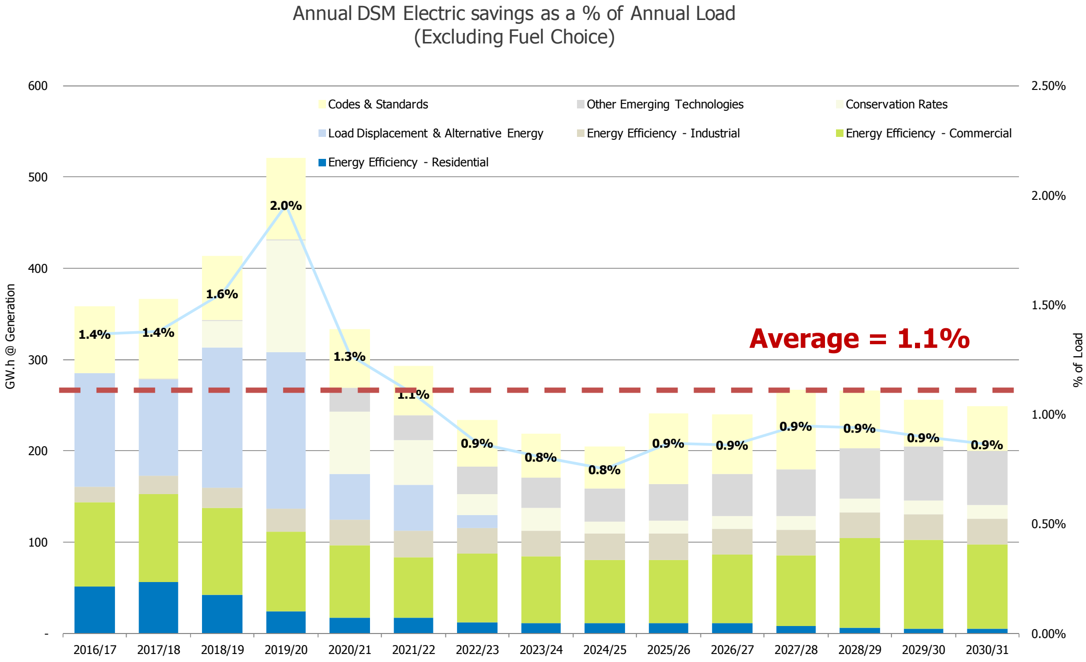


Annual Electric DSM Savings as a % of Annual Load

The following charts depict Manitoba Hydro’s annual electric DSM efforts in relation to annual electric load growth.



Annual DSM Electric savings as a % of Annual Load
(Including Fuel Choice)



Annual DSM Electric savings as a % of Annual Load
(Excluding Fuel Choice)

2016 Demand Side Management Plan
Annual Utility Costs (000's $)

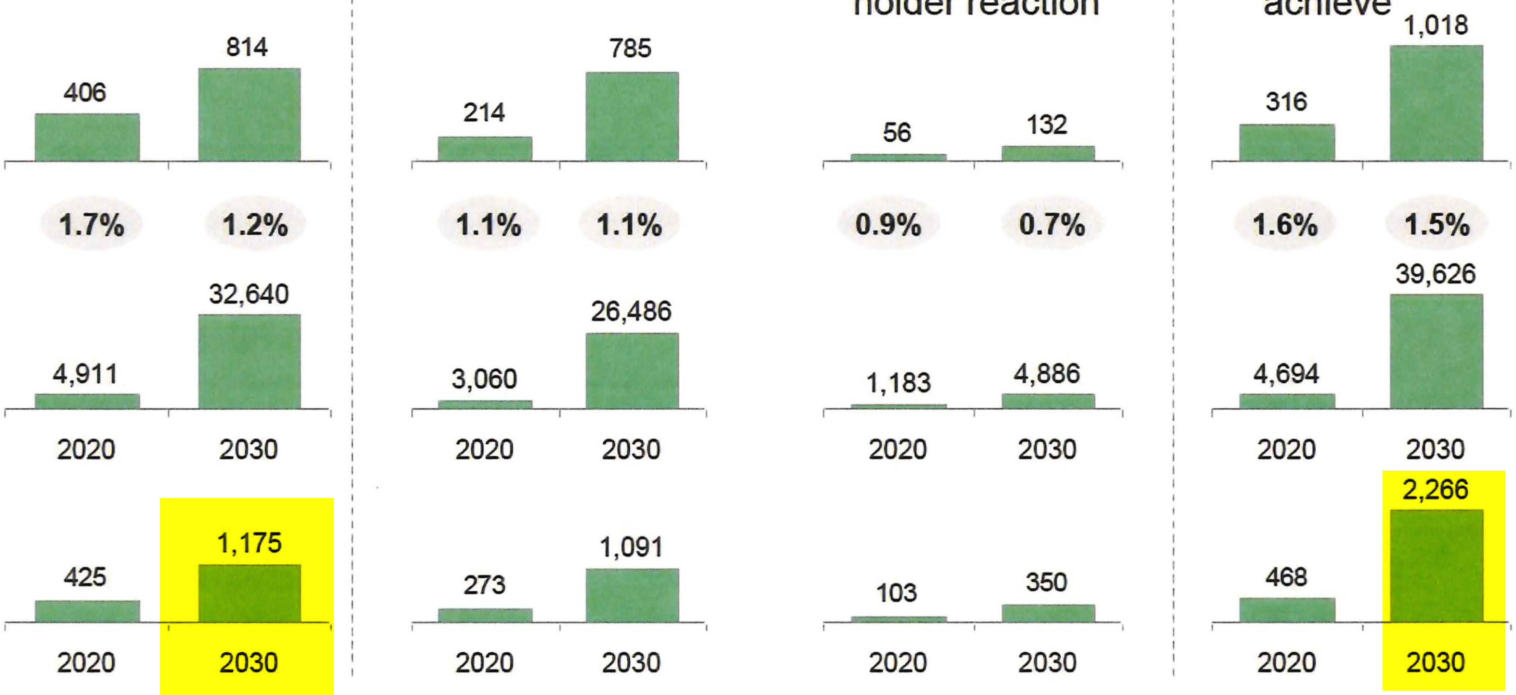
	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
New Homes Program	$292	$459	$757	$901	$580	-	-	-	-	-	-	-	-	-	-	$2,989	
Home Insulation Program	$1,679	$1,493	$1,429	$1,355	$1,251	$1,168	$1,130	$1,012	$977	$956	$818	$174	-	-	-	$13,443	
Affordable Energy Program	$2,096	$2,033	$2,019	$2,020	$1,534	$1,527	$1,524	$1,525	$1,530	$1,515	$1,424	$1,435	$1,448	$1,462	$1,478	$24,570	
Water and Energy Saver Program	$1,199	$1,353	$1,242	-	-	-	-	-	-	-	-	-	-	-	-	$3,794	
Refrigerator Retirement Program	$1,911	$1,602	$1,469	$1,178	$1,228	$988	$47	-	-	-	-	-	-	-	-	$8,423	
Drain Water Heat Recovery Initiative	$91	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$91	
Residential LED Lighting Program	$3,008	$2,561	$1,870	-	-	-	-	-	-	-	-	-	-	-	-	$7,438	
Community Geothermal Program	$1,105	$1,357	$1,563	$1,668	$1,679	$1,764	$2,280	$1,891	$1,719	$1,809	$2,257	$1,694	$1,084	$676	-	$22,546	
Appliances	$363	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$363	
HRV Controls	$419	$434	$372	-	-	-	-	-	-	-	-	-	-	-	-	$1,225	
Power Bars	$9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$9	
Smart Thermostats	$53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$53	
Plug-in Timers	$26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$26	
Community Energy Plan	$62	$118	$120	$123	$125	$81	$82	$84	$86	$88	$90	$92	$93	$95	$97	$1,437	
Subtotal	$12,312	$11,411	$10,842	$7,245	$6,397	$5,528	$5,064	$4,513	$4,312	$4,367	$4,589	$3,395	$2,625	$2,234	$1,576	$86,409	8%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Power Smart PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Residential Earth Power Loan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
COMMERCIAL																	
Incentive Based																	
Commercial Lighting Program	$8,257	$8,145	$8,209	$8,499	$8,227	$8,085	$8,291	$8,224	$7,851	$7,787	$7,842	$8,124	$8,568	$8,853	$8,304	$123,265	
LED Roadway Lighting Conversion Program	$10,993	$9,858	$10,957	$10,801	$1,778	-	-	-	-	-	-	-	-	-	-	$44,388	
Commercial Building Envelope - Windows Program	$501	$483	$512	$564	$603	$643	$657	$671	$685	$759	$811	$833	$850	$868	$887	$10,326	
Commercial Building Envelope - Insulation Program	$799	$722	$664	$709	$724	$738	$754	$775	$791	$808	$825	$848	$865	$884	$902	$11,808	
Commercial Geothermal Program	$461	$569	$622	$785	$983	$1,028	$1,099	$1,169	$1,212	$1,274	$1,384	$1,423	$1,518	$1,563	$1,617	$16,705	
Commercial HVAC Program - Chillers (Water-Cooled)	$192	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$192	
Commercial HVAC Program - CO2 Sensors	$181	$187	$200	$204	$213	$218	$225	$232	$2	$2	$2	$2	$2	$2	$2	$1,675	
Commercial HVAC Program - HRVs	$475	$768	$888	$957	$1,023	$1,093	$1,168	$1,340	$1,433	$1,533	$1,735	$1,840	$1,951	$2,201	$2,312	$20,716	
Commercial HVAC Program - Air Cooled Chillers	-	$463	$605	$655	$708	$763	$820	$879	$940	$960	$980	$1,001	$1,022	$1,043	$1,066	$11,903	
Commercial Custom Measures Program	$404	$459	$469	$479	$489	$499	$535	$573	$612	$625	$666	$795	$841	$858	$876	$9,180	
Commercial Building Optimization Program	$158	$174	$206	$217	$228	$233	$244	$250	$262	$268	$281	$287	$301	$329	$336	$3,772	
New Buildings Program	$1,049	$1,770	$1,267	$1,570	$1,884	$2,261	$549	$561	-	-	-	-	-	-	-	$10,911	
Commercial Refrigeration Program	$450	$720	$763	$742	$722	$851	$863	$924	$1,000	$909	$1,081	$1,097	$1,214	$1,163	$1,030	$13,530	
Commercial Kitchen Appliance Program	$78	$29	-	-	-	-	-	-	-	-	-	-	-	-	-	$107	
Network Energy Management Program	$27	$44	$55	-	-	-	-	-	-	-	-	-	-	-	-	$127	
Internal Retrofit Program	$935	$980	$977	$848	$1,270	$967	$988	$434	$443	$452	$419	$428	$437	$446	$456	$10,480	
Power Smart Shops	$674	$619	$632	$635	$649	$240	-	-	-	-	-	-	-	-	-	$3,449	
Power Smart Energy Manager	$78	$167	$289	$320	$249	$202	$206	$210	$214	$219	$101	$44				$2,204	
Race to Reduce	$128	$131	$134	$137	-	-	-	-	-	-	-	-	-	-	-	$530	
Parking Lot Controller	$358	$169	-	-	-	-	-	-	-	-	-	-	-	-	-	$527	
Subtotal	$26,200	$26,457	$27,449	$28,122	$19,748	$17,820	$16,399	$16,240	$15,445	$15,595	$16,126	$16,720	$17,553	$18,171	$17,748	$295,795	27%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
INDUSTRIAL																	
Performance Optimization Program	$3,310	$5,129	$6,592	$7,359	$8,154	$8,327	$8,502	$8,682	$8,865	$9,053	$9,244	$9,439	$9,639	$9,842	$10,050	$122,187	
Subtotal	$3,310	$5,129	$6,592	$7,359	$8,154	$8,327	$8,502	$8,682	$8,865	$9,053	$9,244	$9,439	$9,639	$9,842	$10,050	$122,187	11%
ENERGY EFFICIENCY SUBTOTAL	$41,822	$42,996	$44,883	$42,725	$34,300	$31,675	$29,965	$29,435	$28,622	$29,015	$29,960	$29,555	$29,817	$30,247	$29,374	$504,391	45%
LOAD MANAGEMENT																	
Curtailable Rate Program	$6,112	$6,241	$6,373	$6,508	$6,645	$6,786	$6,929	$7,075	$7,225	$7,378	$7,533	$7,693	$7,855	$8,021	$8,190	$106,566	
LOAD MANAGEMENT SUBTOTAL	$6,112	$6,241	$6,373	$6,508	$6,645	$6,786	$6,929	$7,075	$7,225	$7,378	$7,533	$7,693	$7,855	$8,021	$8,190	$106,566	10%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$848	$1,664	$2,702	$3,942	$10,120	$10,733	$7,475	$8	$9	$9	$9	$9	$9	$10	-	$37,547	
Customer Sited Load Displacement	$3,911	$12,235	$27,850	$22,404	$5,284	$6,207	$458	$420	$426	$433	$442	$452	$461	$451	$412	$81,846	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$4,758	$13,898	$30,552	$26,346	$15,404	$16,941	$7,932	$428	$435	$442	$451	$461	$471	$461	$412	$119,393	11%
CONSERVATION RATES																	
Conservation Rates - Residential	-	$2,042	$2,085	$2,129	$1,631	$1,110	$1,134	$579	$591	$603	$308	$315	$321	$328	-	$13,177	
Conservation Rates - Commercial	-	$1,532	$2,085	$2,662	$2,718	$1,110	$1,134	$1,158	$1,182	$1,207	$616	$629	$643	$656	-	$17,331	
CONSERVATION RATES SUBTOTAL	-	$3,574	$4,171	$4,791	$4,349	$2,220	$2,267	$1,736	$1,773	$1,810	$924	$944	$964	$984	-	$30,509	3%
FUEL CHOICE																	
Fuel Choice	-	$10,315	$10,524	$10,746	$10,973	$11,205	-	-	-	-	-	-	-	-	-	$53,765	
FUEL CHOICE SUBTOTAL	-	$10,315	$10,524	$10,746	$10,973	$11,205	-	-	-	-	-	-	-	-	-	$53,765	5%
OTHER EMERGING TECHNOLOGIES																	
Residential Air Source Heat Pumps Program	-	-	-	-	$40	$116	$158	$185	$206	$223	$252	$289	$314	$347	$354	$2,485	
Residential Future Opportunities	-	-	-	-	$4,131	$4,219	$4,308	$4,399	$4,492	$4,587	$4,683	$4,782	$4,883	$4,987	$5,092	$50,563	
Residential Solar Photovoltaics Program (PV)	-	-	-	$49	$162	$246	$414	$777	$1,441	$2,507	$3,774	$4,984	$6,284	$7,377	$7,854	$35,870	
Residential Solar Thermal Program - Water Heating	$5	$51	$50	$53	$57	$58	$24	-	-	-	-	-	-	-	-	$299	
Residential Solar Thermal Program - Pool Heating	$2	$19	$19	$20	$22	$22	$24	$26	$28	$30	$33	$35	$40	$43	$48	$410	
Commercial Future Opportunities	-	-	-	-	$4,458	$4,552	$4,648	$4,746	$4,846	$4,949	$5,053	$5,160	$5,269	$5,380	$5,494	$54,554	
Commercial Solar Photovoltaics Program (PV)	-	-	-	$160	$557	$1,011	$1,895	$3,360	$5,058	$7,297	$9,594	$12,167	$14,240	$15,966	$16,304	$87,609	
Commercial Variable Speed and Frequency Drives	$8	$142	$187	$191	$191	$193	$192	$196	$198	$200	$197	$201	$205	$209	$214	$2,723	
Industrial Future Opportunities	-	-	-	-	$4,892	$4,996	$5,101	$5,209	$5,319	$5,431	$5,546	$5,663	$5,783	$5,905	$6,030	$59,877	
OTHER EMERGING TECHNOLOGIES SUBTOTAL	$15	$212	$257	$473	$14,510	$15,413	$16,765	$18,897	$21,589	$25,222	$29,133	$33,282	$37,018	$40,215	$41,390	$294,388	27%
Subtotal of Programs	$52,708	$77,237	$96,760	$91,590	$86,182	$84,240	$63,858	$57,573	$59,644	$63,867	$68,001	$71,934	$76,124	$79,928	$79,365	$1,109,011	100%
Program Support	$4,129	$4,033	$3,956	$4,039	$4,124	$4,212	$4,301	$4,391	$4,484	$4,579	$4,676	$4,774	$4,875	$4,978	$5,083	$66,635	
Total Utility Costs (2016 to 2030)	$56,837	$81,270	$100,716	$95,629	$90,307	$88,451	$68,159	$61,964	$64,129	$68,446	$72,677	$76,708	$80,999	$84,906	$84,449	$1,175,646	
Total Committed to Date																$509,592	
TOTAL UTILITY COSTS (1989 to 2030)	**$56,837**	**$81,270**	**$100,716**	**$95,629**	**$90,307**	**$88,451**	**$68,159**	**$61,964**	**$64,129**	**$68,446**	**$72,677**	**$76,708**	**$80,999**	**$84,906**	**$84,449**	**$1,685,237**	

Note: May not add up due to rounding.

DSM

Three alternative electric DSM scenarios assessed beside MH's base Power Smart Plan

	Status quo DSM: Power Smart Plan	Balanced DSM	Significant ramp-down DSM	PUB imposed 1.5% target
Description	• Base Power Smart Plan • All possible initiatives	• Unchanged new resource date • Shifting CAPEX • Risk of stake-holder concerns	• Radical reduction of DSM expense • Date for new gen advanced to early 2030s • Risk of stake-holder reaction	• Meet 1.5% electric load PUB target • Likely if moved outside MH • $1B+ costs to achieve
Capacity (MW) (2020/2030)	406 814	214 785	56 132	316 1,018
	1.7% 1.2%	1.1% 1.1%	0.9% 0.7%	1.6% 1.5%
Cumulative energy (GWh) (until 2020/2030)	4,911 32,640	3,060 26,486	1,183 4,886	4,694 39,626
Cumulative total utility costs (5 year / 15 year)	425 1,175	273 1,091	103 350	468 2,266



xx% DSM as avg. % of load

PUB MFR 77

Financial Information

Graphs and supporting IFF details of retained earnings over the 20 year forecast period for the following scenarios:
i. 50% of proposed DSM investments and 50% of expected savings
ii. 100% of proposed DSM investments but only 50% of expected savings
iii. 0% of proposed DSM investments and 0% of expected savings
iv. Most current IFF forecast
[PUB/MH I-59, 2015/16 GRA]

Starting in 2018/19, the following assumptions were used for the above scenarios:

i. 50% of proposed DSM investments and 50% of expected savings

- DSM utility costs between 2018/19 and 2035/36 are $0.7 billion lower;
- Projected rate increases are the same as those projected in MH16;
- Projected Manitoba domestic revenue is $1.9 billion higher (including additional revenue) 2035/36 compared to MH16 due to the reduction in DSM savings;
- The reduction in DSM savings results in less energy available for export and reduces projected net export revenue (net of water rentals and fuel and power purchased) by $1.1 billion over the period to 2035/36 compared to MH16; and
- No new thermal energy resources are required to meet firm load within the MH16 20 Year Outlook period to 2035/36.

ii. 100% of proposed DSM investments but only 50% of expected savings

- DSM utility costs are the same as those projected in MH16;
- Projected rate increases are the same as MH16;
- Projected Manitoba domestic revenue is $1.9 billion higher (including additional revenue) to 2035/36 compared to MH16 due to the reduction in DSM savings; and
- The reduction in DSM savings results in less energy available for export and reduces projected net export revenue (net of water rentals and fuel and power purchased) by $1.1 billion over the period to 2035/36 compared to MH16; and
- No new thermal energy resources are required to meet firm load within the MH16 20 Year Outlook period to 2035/36.

iii. 0% of proposed DSM investments and 0% of expected savings

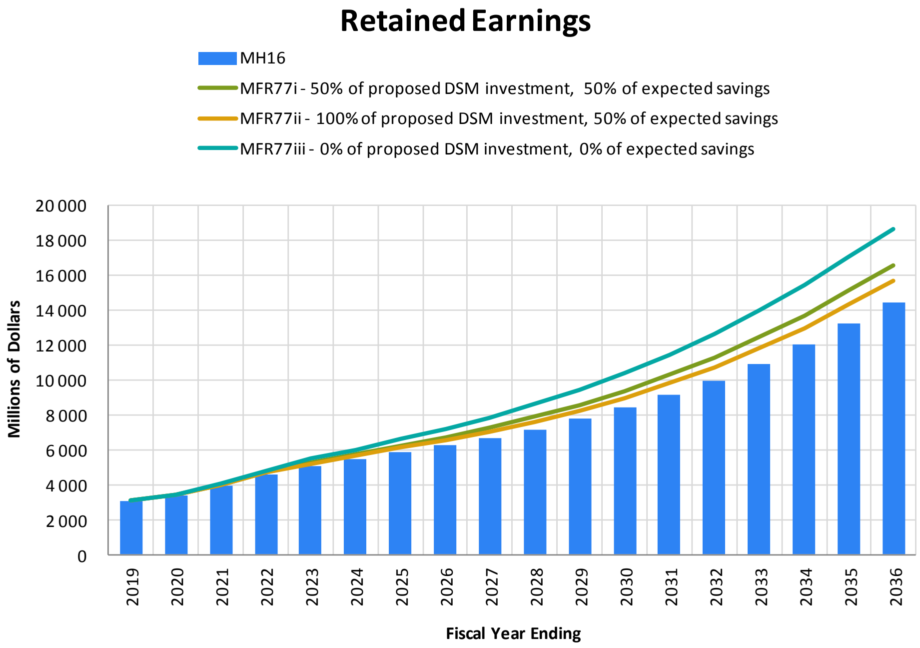
- DSM utility costs are assumed to be $0 starting in 2018/19, a reduction of $1.5 billion compared to MH16;
- Projected rate increases are the same as MH16;
- Projected Manitoba domestic revenue is $3.9 billion higher (including additional revenue) to 2035/36 compared to MH16 due to the reduction in DSM savings; and
- The reduction in DSM savings results in less energy available for export and reduces projected net export revenue (net of water rentals and fuel and power purchased) by $2.1 billion over the period to 2035/36 compared to MH16.
- Due to the reduction in DSM savings, new thermal energy resources are required by 2032/33 at an estimated cost of $0.4 billion.

The figures below summarize the incremental impact on retained earnings compared to MH16 for the above three scenarios. All 3 alternative scenarios assume that the DSM savings reductions are reduced by 50% or 100% across-the-board. In MH16, uncommitted firm energy (i.e., forecast export sales with no term sheet or agreement) is valued essentially at an opportunity price; therefore, the reduction in forecast firm energy sales results in a benefit to Manitoba Hydro as a domestic sale due to weak opportunity prices.

Figure 1. Incremental Increase/Decrease in Retained Earnings

		Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)		
	MH16	MFR77i	MFR77ii	MFR77iii
Fiscal Yr Ending	100% of proposed DSM investment 100% of expected savings	50% of proposed DSM investment 50% of expected savings	100% of proposed DSM investment 50% of expected savings	0% of proposed DSM investment 0% of expected savings
2019	3 083	4	4	7
2020	3 427	25	18	39
2021	3 921	64	42	123
2022	4 594	124	82	241
2023	5 094	196	125	385
2024	5 466	275	171	548
2025	5 898	363	222	731
2026	6 265	460	277	930
2027	6 705	572	340	1 157
2028	7 193	699	411	1 415
2029	7 759	836	486	1 694
2030	8 411	983	570	1 989
2031	9 138	1 150	667	2 316
2032	9 979	1 326	770	2 671
2033	10 929	1 506	876	3 035
2034	12 002	1 689	976	3 416
2035	13 200	1 879	1 081	3 803
2036	14 470	2 057	1 174	4 203

Figure 2. Retained Earnings for All Scenarios



Decreased DSM could improve MH financials in short-term

Executive summary

Interim findings – Aug 9

MH's DSM plan aims to allow customers reduce customer costs and delay generation

- MH Power Smart Plan identifies 41 DSM initiatives at varying levels of customer and utility cost
- Primary objectives of DSM are enabling customers to control costs and delay new generation
- DSM initiatives expected to reduce domestic gross demand by up to 10% by 2030

DSM deferral could potentially contribute to reduce financial pressure in initial years through reduced CAPEX and incremental revenue increase through higher domestic revenues

- MH's electric DSM Plan expected to require \$1.2B CAPEX over 15 years
- Spot opportunity export prices are currently below domestic rates, firm prices above domestic
  - In short term reduced DSM has the potential to increase domestic revenues
  - In longer term firm contracts would likely be above domestic level given market premium

MH performed prioritization of DSM initiatives resulting in four scenarios with ~\$30-65M annual CAPEX reduction and ~\$11-22M annual revenue increase in the next 5 years vs. base plan

- DSM adjustment could help improving operating cash flow by up to 10% and reduce investing cash-flow by up to 5%

Three important issues identified during the assessment of DSM

- Domestic rate increase can trigger demand reduction similar to DSM given 25% customers' price sensitivity
- Setting up an off-balance sheet vehicle to fund DSM could potentially improve the perspective on financials
- Moving DSM to independent external entity financed by MH not seen as beneficial

Any downward adjustment of DSM expected to have further broad risk implications

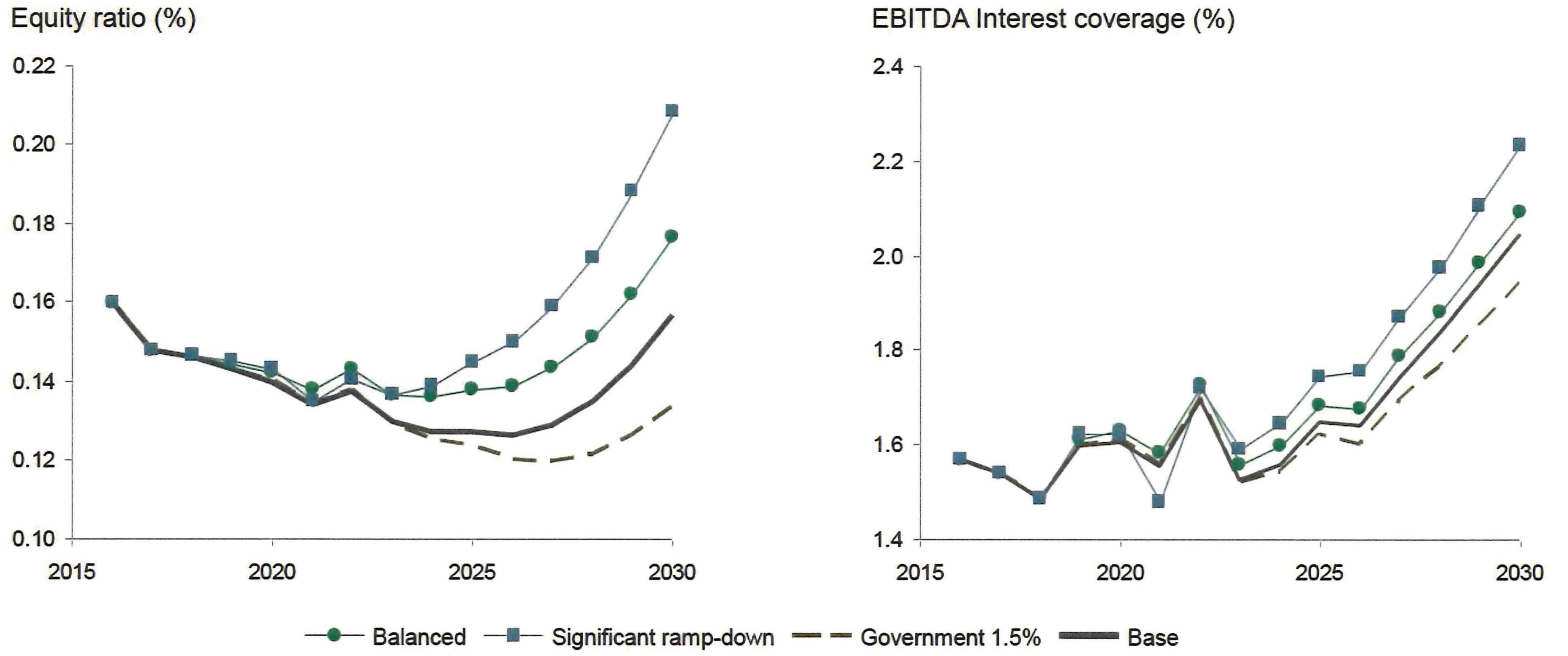
- PUB and external stakeholders anchored on the developed targets defined in the Power Smart Plan
- DSM adjustment need to be implemented with careful stakeholder- and communication actions

DSM adjustment could help improving key financial ratios

Preliminary

Equity ratio rebound can be accelerated

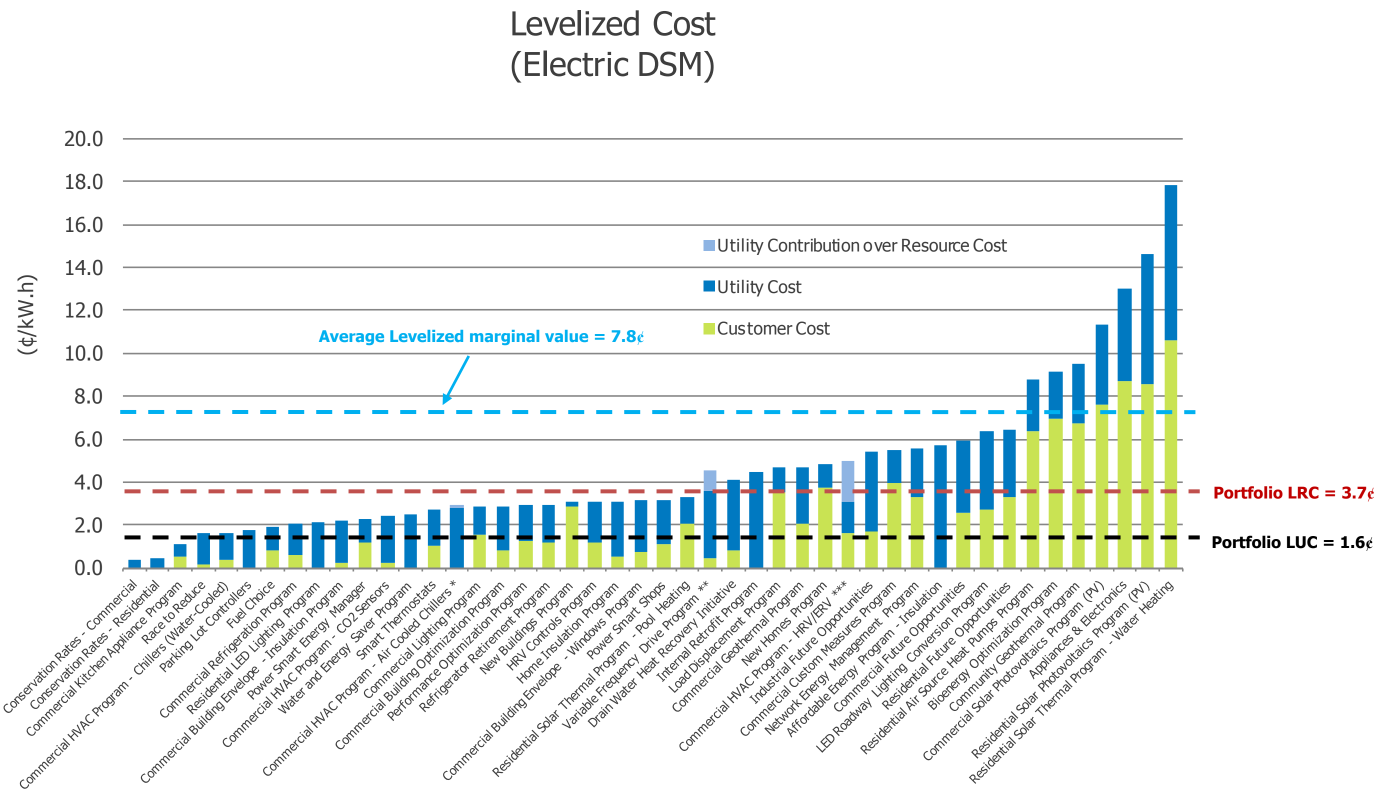
Interest coverage kept at healthier levels



Broad risk implications need to be considered for any downward adjustment of DSM

Electric DSM Levelized Costs

The following chart depicts the levelized costs of Manitoba Hydro's electric DSM portfolio.



* *NOTE: Manitoba Hydro pays incentives to free riders but does not include the savings or the associated incremental product costs related to free riders. Due to high levels of free ridership, the utility cost is higher than the total resource cost of the program. The light blue bar represents the utility investment beyond the resource cost.*

Utility contribution to resource cost:	*2.8 cents*
Customer contribution to resource cost:	*0.0 cents*
Total resource cost:	***2.8 cents***
Utility contribution over resource cost:	*0.1 cents*
Total cost:	***2.9 cents***

** *NOTE: Manitoba Hydro pays incentives to free riders but does not include the savings or the associated incremental product costs related to free riders. Due to high levels of free ridership, the utility cost is higher than the total resource cost of the program. The light blue bar represents the utility investment beyond the resource cost.*

Utility contribution to resource cost:	*3.1 cents*
Customer contribution to resource cost:	*0.4 cents*
Total resource cost:	***3.6 cents***
Utility contribution over resource cost:	*1.0 cents*
Total cost:	***4.6 cents***

*** *NOTE: Manitoba Hydro pays incentives to free riders but does not include the savings or the associated incremental product costs related to free riders. Due to high levels of free ridership, the utility cost is higher than the total resource cost of the program. The light blue bar represents the utility investment beyond the resource cost.*

Utility contribution to resource cost:	*1.5 cents*
Customer contribution to resource cost:	*1.6 cents*
Total resource cost:	***3.1 cents***
Utility contribution over resource cost:	*1.9 cents*
Total cost:	***5.0 cents***

REFERENCE:

Tab 9 Page 2 of 18

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide the derivation of the marginal values.

c) Please explain whether the changes in the export revenue forecast, including the decline in export price forecasts and the elimination of premiums associated with the sale of long term dependable energy and capacity, are reflected in the current marginal value.

RATIONALE FOR QUESTION:

RESPONSE:

b) Marginal value is defined as the cost or value to the system of deferring an increment of load growth to Manitoba Hydro's integrated system. Since the power supplied to residential load requires generation supply, bulk transmission capability and distribution capability, a marginal value has been determined for each of these three components. The transmission and distribution components are based on one-year deferral of planned transmission and distribution capital additions to meet the ongoing capacity requirements. Please see Manitoba Hydro's response to GAC/MH I-39 for the transmission and distribution marginal cost reports.

The generation marginal value represents value of the energy savings on the export market when valued as a long-term firm sale, and incorporates all the associated system costs in order to facilitate the sale. The production costs are determined by undertaking a simulation of system operation for 35-years into the future using an in-house computer model for a wide range of flow cases.

The first simulation run is a base case which corresponds to the IFF case. In order to determine marginal value, a second simulation is undertaken in which the load is reduced from the base case by a constant increment in each month for a total of 500 GWh over the year as an example. The net difference in production costs between the two simulations for each year of the study period is divided by the energy associated with the incremental load change to derive the marginal generation value in dollars per megawatt hour. Transmission and distribution losses are also calculated and added to the generation component to account for the full quantity of generation that is required to serve the end use load. Values are calculated for the summer and winter seasons, and on an annual basis.

The following table contains marginal values used in the 2016 DSM plan (Appendix 7.2). The generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information. Public disclosure of portions of this response would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

2015/16 Basic Marginal Costs Applicable to Distribution Level Programs
Marginal Costs Given at Distribution
(Constant Year 2016 Canadian Dollars)

Notes:
Marginal costs based on a uniform supply with a 100% capacity factor
Marginal costs referred to distribution level (loss factor of 14% to translate back to generation)
US/Cdn Exchange Rates and Escalation Factors (P911 October 12, 2015)
Updated transmission & distribution marginal costs (2015)

5a

Fiscal Year	SUMMER		WINTER					ALL-IN		
	Generation Energy	Generation Capacity	Generation Energy	Generation Capacity	Transmission Capacity	Distribution Capacity	Total Capacity	SUMMER	WINTER	ANNUAL
	$/MW.h	$/kW.Yr	$/MW.h	$/kW.Yr	$/kW.Yr	$/kW.Yr	$/kW.Yr	$/MW.h	$/MW.h	$/MW.h
2016/17	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2017/18	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2018/19	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2019/20	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2020/21	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2021/22	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2022/23	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2023/24	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2024/25	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2035/36	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2036/37	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2037/38	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2038/39	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2039/40	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2040/41	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2041/42	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2042/43	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2043/44	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2044/45	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2045/46	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Cost at 4.15% Discount Rate	[redacted]	[redacted]	[redacted]	[redacted]	49.28	76.48	[redacted]	[redacted]	[redacted]	77.73

30 -year levelized value	(Cents/kW h)	7.8

c) The marginal value used in the 2016 DSM plan is based on the 2015 export price forecast, which includes a premium associated with the sale of long term dependable energy and the value of capacity. As noted in the response to Coalition/MH I-132i, Manitoba Hydro is currently in the process of updating the generation component of the marginal values based on the export price forecast used in the MH16 Update.

($ Millions)	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	2017-2036 20 Year Total
Major New Generation & Transmission	2 355	2 476	2 126	1 274	1 066	746	358	75	4	4	5	**8 134**	**10 491**
Electric Business Operations Capital	574	526	517	516	511	499	521	544	616	640	659	**5 549**	**12 835**
Natural Gas Business Operations Capital	51	31	32	29	31	33	35	34	39	39	40	**343**	**812**
Capital Expenditures Total	**2 980**	**3 033**	**2 675**	**1 819**	**1 609**	**1 278**	**914**	**652**	**659**	**683**	**703**	**14 026**	**24 138**
Year End Outlook Adjustment	(45)	-	-	-	-	-	-	-	-	-	-	**-**	**(45)**
Revised Capital Expenditures Total	**2 935**	**3 033**	**2 675**	**1 819**	**1 609**	**1 278**	**914**	**652**	**659**	**683**	**703**	**14 026**	**24 093**
Demand Side Management	60	66	111	105	100	98	77	71	73	77	81	**858**	**1 762**
CEF16 & Demand Side Management Total	**2 995**	**3 099**	**2 786**	**1 924**	**1 708**	**1 376**	**991**	**723**	**732**	**760**	**784**	**14 884**	**25 855**

The CEF16 totals $14 884 million for the ten year period from 2017/18 through 2026/27. Expenditures for MNG&T total $8 134 million, with the balance of $5 892 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements and ongoing efficiency improvements. In addition, DSM expenditures total $858 million for the same period.

MNG&T expenditures total $10 491 million over the twenty year forecast 2016/17 through 2035/36. Business Operations capital totals $13 602 million over the same period. The twenty year forecast includes projected expenditures for 2016/17 as well as forecast requirements to 2035/36. Over the latter ten years of the forecast period increases for Business Operations capital have been incorporated in order to address expected aging infrastructure requirements

DSM expenditures total $1 762 million over the twenty year forecast. The increase within the twenty year forecast reflects continued investment in both Electric and Natural Gas DSM programs.

REFERENCE:

Appendix 7.2
2016/17 Supplemental Filings, Attachment 24
2015/16 & 2016/17 GRA, Appendix 8.1
Appendix 7.3, Pages 9 and 18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that compares the total (at the meter) incremental DSM savings forecast for the years 2014/15 and beyond as submitted in: i) the last GRA (2014-2017 Power Smart Plan and 2014-2029 Supplemental Report, ii) the 2016/17 Supplemental Filing (2015/16 Power Smart Plan and 2015-2030 Supplemental Report), and iii) the current GRA (2016/17 DSM Plan and Supplemental Report 2016-2031). Note: Please include actual values for those years where applicable.

b) Do the DSM forecasts include any allowance for loss of persistence of the effects of DSM programs or do they assume that the program saving will continue for the entire forecast period? If the later, what is the basis for this assumption? If the former, how is this incorporated into the DSM savings forecast?

c) Did the forecast of DSM savings change as between IFF16 and IFF16-Updated? If so, please provide the basis for the revised DSM savings forecast and include these values as item (iv) in the response to part (a).

d) Please provide a schedule that sets out the forecast DSM spending from 2014/15 (separately reporting the portion that is expensed vs. that deferred and amortized) consistent with three Plans referenced in part (a). Where applicable, please include actual spending values for 2014/15 through 2016/17.

e) Did the forecast of DSM spending change as between IFF16 and IFF16-Updated? If so, please provide the basis for the revised DSM spending forecast and include these values as item (iv) in the response to part (d).

f) Please explain how the values provided in Appendix 7.3 (specifically Figure 5 for 2014, 2015 and 2016 DSM Plans and page 18 for the 2016 DSM Plan) are derived from the detailed forecasts provide in the Supplemental Reports (e.g. Appendix 7.2, 2016-2031 Supplemental Report, Appendix A.2).

RATIONALE FOR QUESTION:

To understand the changes in DSM forecast savings and spending since the last GRA.

RESPONSE:

a) The following table summarizes the total incremental DSM savings forecast (excluding savings related to Codes & Standards) for the years 2014/15 and beyond:

	Incremental DSM Savings			
	Item (i)	***Item (ii)***	***Item (iii)***	***Item (iv)***
	2014-17 Power Smart Plan – 15 Year Supplemental Report	***2015/16 Power Smart Plan – 15 Year Supplemental Report***	***2016 DSM Plan - 15 Year Supplemental Report***	***2016 DSM Plan (Updated)***
	GW.h @ Meter	***GW.h @ Meter***	***GW.h @ Meter***	***GW.h @ Meter***
2014/15	254	191 *	191 *	191 *
2015/16	282	193	247 *	247 *
2016/17	362	226	255	330 **
2017/18	345	394	300	212
2018/19	413	327	358	358
2019/20	385	364	436	436
2020/21	327	247	290	290
2021/22	271	255	264	264
2022/23	199	148	162	162
2023/24	196	141	151	151
2024/25	163	132	141	141
2025/26	159	145	145	145
2026/27	155	150	154	154
2027/28	163	159	159	159
2028/29	163	164	179	179
2029/30	-	165	181	181
2030/31	-	-	177	177

Note: * Reflects actual evaluated incremental savings for 2014/15 and 2015/16
** Reflects preliminary unevaluated incremental savings for 2016/17

b) The DSM forecasts include allowances for loss of persistence of the effects of DSM programs. Assumptions are made at the DSM program level regarding the persistence of energy and demand savings to the end of the product life that impacts the DSM forecast.

c) The DSM savings changed between IFF16 and IFF16-Updated. Please see section 2.2 - Demand Side Management - on page 4 of Tab 3 Supplement – Forecast Update for the basis for the revised savings. Please refer to Item (iv) – 2016 DSM Plan (Updated) in the table provided in response to part a) for the values.

d) The following table summarizes the forecast DSM spending from 2014/15 and beyond:

Forecast DSM Spending (millions $)												
	Item (i)			*Item (ii)*			*Item (iii)*			*Item (iv)*		
	2014-17 Power Smart Plan – 15 Year Supplemental Report			*2015/16 Power Smart Plan – 15 Year Supplemental Report*			*2016 DSM Plan - 15 Year Supplemental Report*			*2016 DSM Plan (Updated)*		
	Amortized	*Expensed*	*Total*	*Amortized*	*Expensed*	*Total*	*Amortized*	*Expensed*	*Total*	*Amortized*	*Expensed*	*Total*
2014/15	$53.0	$1.2	$54.2	$37.4*	$1.0*	$38.4*	$37.4*	$1.0*	$38.4*	$37.4*	$1.0*	$38.4*
2015/16	$60.1	$1.2	$61.3	$62.3	$1.1	$63.4	$58.2*	$0.9*	$59.2*	$58.2*	$0.9*	$59.2*
2016/17	$76.9	$1.2	$78.1	$56.6	$1.1	$57.7	$56.2	$0.9	$57.1	$50.8**	$1.0**	$51.8**
2017/18	$83.9	$1.2	$85.1	$96.4	$1.1	$97.5	$80.6	$1.0	$81.6	$55.9	$0.9	$56.8
2018/19	$93.7	$1.2	$94.9	$92.3	$1.2	$93.4	$100.1	$1.0	$101.1	$100.1	$1.0	$101.1
2019/20	$78.2	$1.3	$79.5	$88.0	$1.2	$89.2	$95.1	$1.0	$96.1	$95.1	$1.0	$96.1
2020/21	$72.5	$1.3	$73.8	$90.2	$1.2	$91.4	$89.7	$1.0	$90.7	$89.7	$1.0	$90.7
2021/22	$60.8	$1.3	$62.2	$94.2	$1.2	$95.4	$87.8	$1.0	$88.9	$87.8	$1.0	$88.9
2022/23	$49.9	$1.4	$51.3	$70.7	$1.2	$71.9	$67.5	$1.1	$68.6	$67.5	$1.1	$68.6
2023/24	$49.6	$1.4	$51.0	$65.7	$1.3	$67.0	$61.3	$1.1	$62.4	$61.3	$1.1	$62.4
2024/25	$47.5	$1.4	$48.9	$69.2	$1.3	$70.5	$63.3	$1.1	$64.4	$63.3	$1.1	$64.4
2025/26	$48.3	$1.4	$49.7	$74.7	$1.3	$76.0	$67.4	$1.1	$68.6	$67.4	$1.1	$68.6
2026/27	$47.2	$1.5	$48.6	$79.9	$1.3	$81.2	$71.6	$1.2	$72.8	$71.6	$1.2	$72.8
2027/28	$47.1	$1.5	$48.6	$86.2	$1.4	$87.6	$75.6	$1.2	$76.8	$75.6	$1.2	$76.8
2028/29	$48.2	$1.5	$49.7	$92.8	$1.4	$94.2	$79.8	$1.2	$81.0	$79.8	$1.2	$81.0
2029/30	-	-	$0.0	$94.7	$1.4	$96.1	$83.7	$1.2	$84.9	$83.7	$1.2	$84.9
2030/31	-	-	-	-	-	-	$83.2	$1.3	$84.4	$83.2	$1.3	$84.4
Total	$917.0	$19.9	$937.0	$1,251.1	$19.7	$1,270.8	$1,258.5	$18.3	$1,276.8	$1,228.5	$18.3	$1,246.8

Note: * Reflects actual spending for 2014/15 and 2015/16

** Reflects preliminary unevaluated spending for 2016/17

e) The forecast of DSM spending changed between IFF16 and IFF16-Updated. The MH16 Update incorporates planned spending from the 2017/18 Power Smart Plan developed in consultation with the Province as outlined under *The Energy Savings Act*. The planned spending in the longer term (2018/19 to 2029/30), included in the 2016/17

DEMAND SIDE MANAGEMENT PLAN

The 2017/18 DSM Plan was developed through an intensive planning process and it offers programs and initiatives to pursue opportunities in all market sectors; residential, commercial, and industrial. These programs are designed based on in-depth knowledge of the technology and the market environment. An in-depth understanding is essential to ensure that the program design is adequately and effectively addressing the appropriate target market and contains the tools and strategies to address market barriers. The following table outlines the forecasted achievements for 2017/18:

Programs	Participation Definition	2017/18 Participation	Capacity Savings (MW)	Energy Savings (GW.h)	Natural Gas Savings (million m^3)	Utility Investment (millions $)
New Homes Program	No. of houses	260	0.5	0.9	0.1	$0.8
Home Insulation Program	No. of houses	1,781	1.7	3.8	0.6	$3.0
Water and Energy Saver Program	No. of houses	23,650	0.7	3.7	0.8	$1.8
Affordable Energy Program	No. of retrofits	4,835	1.2	3.3	0.9	$6.8
Refrigerator Retirement Program	No. of appliances	8,658	1.0	9.1	-	$1.7
Residential LED Lighting Program	No. of bulbs	763,263	6.3	19.9	-	$3.0
Community Geothermal Program	No. of systems	135	1.1	2.1	-	$0.9
Appliances	No. of appliances	2,600	0.1	0.6	0.0	$0.4
HRV Controls	No. of controllers	978	0.1	0.3	0.0	$0.2
Power Bars	No. of power bars	600	0.0	0.0	-	$0.0
Smart Thermostats	No. of thermostats	1,850	0.2	0.5	0.1	$0.3
Plug-in Timers	No. of timers	3,000	0.0	0.1	-	$0.0
Power Smart Residential Loan	No. of loans	4,492	0.1	0.3	0.4	$0.0
Power Smart PAYS Financing	No. of loans	207	0.0	0.1	0.0	$0.0
Residential Earth Power Loan	No. of loans	77	0.3	0.7	0.0	$0.0
Residential Programs			**13.4**	**45.4**	**2.9**	**$19.1**
Commercial Lighting Program	No. of projects	1,074	12.4	51.1	-	$7.8
LED Roadway Lighting Conversion Program	No. of conversions	29,703	2.0	13.1	-	$10.4
Commercial Building Envelope - Windows Program	No. of projects	160	0.3	0.8	0.2	$0.8
Commercial Building Envelope - Insulation Program	No. of projects	250	1.6	3.5	1.1	$1.9
Commercial Geothermal Program	No. of buildings	9	0.4	0.7	-	$0.4
Commercial HVAC Program - Boilers	No. of boilers	110	-	-	0.8	$0.7
Commercial HVAC Program - Chillers (Water-Cooled)	No. of chillers	2	0.0	1.2	-	$0.1
Commercial HVAC Program - CO2 Sensors	No. of sensors	123	0.2	0.3	0.1	$0.2
Commercial HVAC Program - HRV/ERV	No. of units	7	0.1	0.2	0.0	$0.2
Commercial HVAC Program - Water Heaters	No. of water heaters	44	-	-	0.1	$0.1
Commercial Custom Measures Program	No. of projects	24	0.3	1.9	0.3	$0.7
Enhanced Building Operations Program	No. of buildings	4	0.1	0.8	0.2	$0.5
New Buildings Program	No. of buildings	25	2.1	7.1	0.2	$2.3
Commercial Refrigeration Program	No. of locations	292	0.7	7.0	0.0	$0.5
Commercial Kitchen Appliance Program	No. of appliances	78	0.1	0.2	0.0	$0.1
Network Energy Management Program	No. of licenses	500	0.0	0.1	0.0	$0.0
Internal Retrofit Program	No. of projects	52	0.4	2.5	0.0	$1.2
Power Smart Shops	No. of projects	817	0.3	2.0	0.0	$0.9
Race to Reduce	No. of buildings	25	0.5	4.3	0.3	$0.2
Parking Lot Controller	No. of controllers	42	0.0	0.8	-	$0.1
Power Smart for Business PAYS Financing	No. of loans	25	0.0	0.0	0.0	$0.0
Commercial Programs			**21.5**	**97.7**	**3.4**	**$29.1**
Performance Optimization Program	No. of projects	62	1.4	11.0	-	$2.5
Natural Gas Optimization Program	No. of projects	12	-	-	2.5	$1.0
Industrial Programs			**1.4**	**11.0**	**2.5**	**$3.5**
Energy Efficiency Subtotal			**36.2**	**154.1**	**8.8**	**$51.7**
Curtailable Rate Program	No. of customers	3	168.7	-	-	$6.1
Load Management			**168.7**	**0.0**	**0.0**	**$6.1**
Bioenergy Optimization Program	No. of projects	9	6.7	18.8	-	$1.1
Customer Sited Load Displacement	No. of customers	2	8.9	64.1	-	$6.7
Load Displacement & Alternative Energy			**15.6**	**82.9**	**0.0**	**$7.8**
Residential Solar Photovoltaics Program (PV)	No. of systems	50	0.0	0.5	0.0	$0.5
Commercial Solar Photovoltaics Program (PV)	No. of systems	8	0.0	0.6	0.0	$0.4
Other Emerging Technologies			**0.0**	**1.1**	**0.0**	**$0.9**
Codes, Standards & Regulations			17.9	72.2	3.6	-
Interactive Effects			-	-	-3.0	-
Program Support			-	-	-	$5.3
Demand Side Management Plan - 2017/18			**238**	**310**	**9.4**	**$71.8**

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Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba

MANITOBA HYDRO
August 2012

Manitoba Hydro

EXECUTIVE SUMMARY

This report outlines the economic, load and environmental impacts of using electricity (including geothermal technology) instead of using natural gas for space and water heating purposes. The economic impact is assessed from the customer's and the utility's perspective along with a high level assessment of provincial leakage (i.e. the net impact of changes to extra-provincial natural gas purchases and electricity export sales). The environmental (greenhouse gas emission) impact is assessed from both a provincial and a global perspective. The scope of this assessment does not consider future uncertainty associated with a number of influential factors, including potential electricity rate structure changes (e.g. inverted rates) and potential changing Canadian and US government policies related to greenhouse gas (GHG) emissions. The assessment also does not account for any costs which may result from large-scale upgrading of Manitoba Hydro's electrical infrastructure due to significant energy demand changes.

||| Space Heating

The following table summarizes the load, economic and environmental impacts of using electricity instead of natural gas for space heating in a typical Manitoba residential home. Impacts are analyzed over the life of the equipment (i.e. 25 years). Values in brackets indicate a negative impact from an economic perspective and represent a reduction in GHG emissions from an environmental perspective.

Impact of Converting from Natural Gas to Electric Space Heat

Average Residential Home from Natural Gas to:	Electric Furnace	Geothermal (SCOP 2.5)
Annual Energy Load Impact		
Electric Load Impact (kW.h)	16,391	6,556
Natural Gas Load Impact (cu.m)	(1,776)	(1,776)
Economic Impact		
Utility Perspective (Electric)	($3,223)	($1,563)
Utility Perspective (Natural Gas)	($4,107)	($4,107)
Customer Perspective	($7,737)	($11,276)
Integrated Utility / Customer Perspective	($15,067)	($16,946)
Net Provincial Inflow (Leakage)	($6,271)	$1,061*
Annual Environmental Impact		
Manitoba (kg $C0_2$e/year)	(3,374)	(3,374)
US - MISO Region** (kg $C0_2$e/year)	0 to 12,293	0 to 4,917
Net Global**(kg $C0_2$e/year)	(3,374) to 8,919	(3,374) to 1,543

**The provincial inflow benefits will be offset by higher cost of geothermal units relative to the cost of natural gas furnaces and air conditioners (i.e. estimated at $2,000 to $3,000).*

***The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

Net Economic Impact of Fuel Switching (over the life of the equipment) Average Residential Home

	Gas to Electric Furnace	Gas to Geothermal (SCOP 2.5*)	Conventional Gas to Electric Water Heat
Utility Perspective (Electric)	($3,223)	($1,563)	($10)
Utility Perspective (Natural Gas)	($4,107)	($4,107)	($317)
Customer Perspective - Remaining Natural Gas Service	($9,146)	($12,685)	($727)
Customer Perspective - No Remaining Natural Gas Service	($7,737)	($11,276)	n/a
Integrated Utility / Customer Perspective	($15,067)	($16,946)	($1,054)

**A sensitivity analysis outlining the impacts of using a geothermal system with SCOP of 3.5 is presented in section 5.0.*

Utility Perspective – Changing to an electric space heating or water heating system results in a negative economic impact from the utility's perspective for both electricity and natural gas operations.

From the electric perspective, customers would be using more electricity, resulting in increased domestic electric revenues. However, reduced export revenues and the cost of advancing new electric infrastructure would be higher than the additional revenue gained domestically, therefore resulting in an overall negative impact.

From the natural gas perspective, customers would be consuming less natural gas, thereby decreasing revenues to Manitoba Hydro. This loss outweighs the avoided costs of purchasing natural gas and transportation costs. Therefore, the net result is a negative impact to the utility.

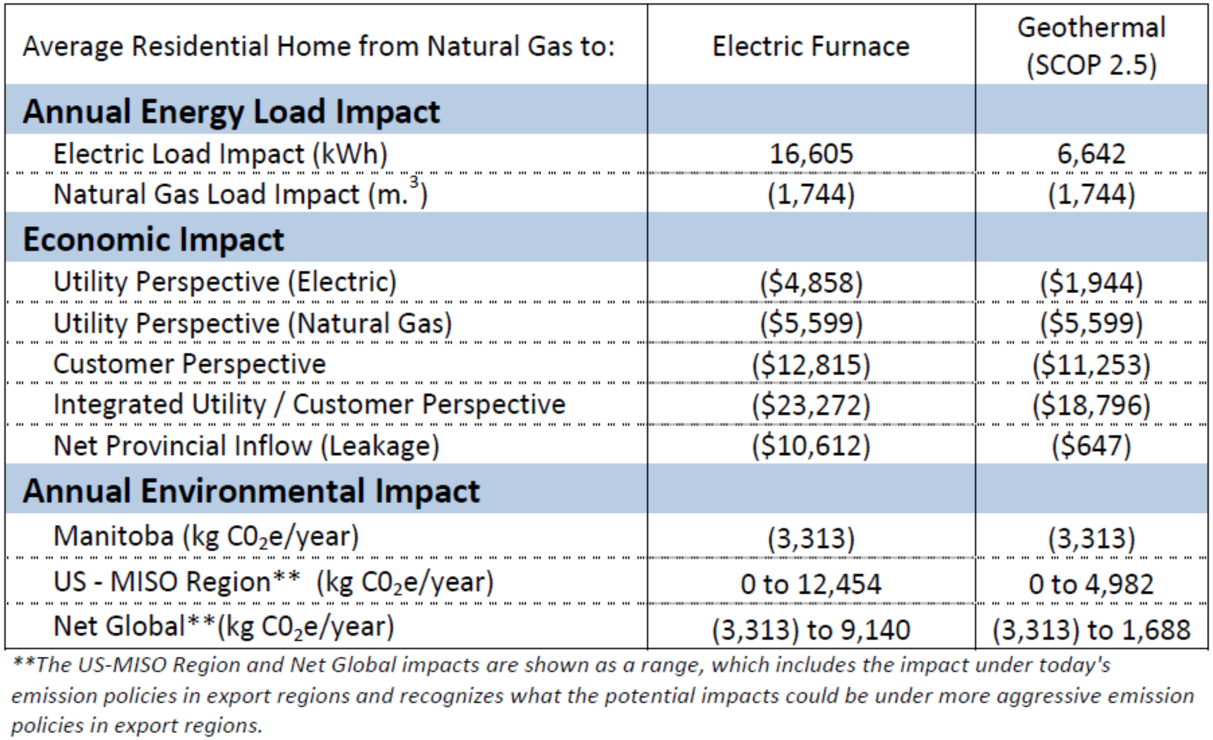
Customer Perspective – Changing from a natural gas space or water heating system to an electric system results in a negative economic impact to a residential customer over the life of the system. It is important to note that in an existing home, choosing an electric water heater over a less costly conventional natural gas water heater results in a negative economic impact to the customer assuming no adjustments are required to the chimney ventilation. If adjustments to the chimney are required, installation costs could increase by approximately $550.

The analysis for the Customer Perspective - Remaining Natural Gas Service assumes that the customer maintains their gas service for other appliances in the home (e.g. fireplace, stove, BBQ). If the customer were to completely eliminate natural gas service to the home, they would also save the cost of the basic monthly charge. The NPV of the natural gas basic monthly charge over 25 years (i.e. the assessment period for space heating) is $2,257. As such, the negative impact of switching from natural gas to an electric furnace decreases for the customer, as outlined in the Customer Perspective – No Remaining Gas Service.

Integrated Utility/Customer Perspective – From a combined utility and customer perspective, changing to an electric space heating or water heating system in an average residential home results in an overall negative economic impact.

2016 Fuel Switching Analysis - Summary

Impact of Converting from Natural Gas Space Heating to Electric Space Heating



Average Residential Home from Natural Gas to:	Electric Furnace	Geothermal (SCOP 2.5)
Annual Energy Load Impact		
Electric Load Impact (kWh)	16,605	6,642
Natural Gas Load Impact (m.^{3})	(1,744)	(1,744)
Economic Impact		
Utility Perspective (Electric)	($4,858)	($1,944)
Utility Perspective (Natural Gas)	($5,599)	($5,599)
Customer Perspective	($12,815)	($11,253)
Integrated Utility / Customer Perspective	($23,272)	($18,796)
Net Provincial Inflow (Leakage)	($10,612)	($647)
Annual Environmental Impact		
Manitoba (kg C0$_2$e/year)	(3,313)	(3,313)
US - MISO Region** (kg C0$_2$e/year)	0 to 12,454	0 to 4,982
Net Global**(kg C0$_2$e/year)	(3,313) to 9,140	(3,313) to 1,688

***The US-MISO Region and Net Global impacts are shown as a range, which includes the impact under today's emission policies in export regions and recognizes what the potential impacts could be under more aggressive emission policies in export regions.*

REFERENCE:

Appendix 9.14 Page 18 of 20

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide Manitoba Hydro's current position on whether the use of electricity for space heating in Manitoba has less or more global climate change impact than space heating with natural gas in Manitoba.

RATIONALE FOR QUESTION:

RESPONSE:

When analyzing the global climate change impact of residential natural gas and electric furnaces, both greenhouse gas ("GHG") emission impacts inside and outside of Manitoba are taken into account.

Direct combustion emissions occur when fossil fuel is used for a specific purpose. The base emissions factor for natural gas combustion of 1.9 kg carbon dioxide equivalent (CO_2e) per m^3 is utilized in the calculation of GHG emissions. In Canada, this emissions factor is utilized by Environment Canada in its GHG inventory assessments and is generally appropriate for residential natural gas furnaces.

Altering the level of Manitoba exports has implications within the broader regional electricity market. Manitoba Hydro's primary export market is the Midwest Independent System Operator ("MISO") region and the marginal generation in MISO is fossil fuel based. The average of emission factors for additional units of fossil generation needed, or avoided, due to changing Manitoba electricity exports is estimated at approximately 750 kg CO_2e per MWh. This estimate was based upon current MISO market conditions and existing policies and only includes the direct burner tip emissions from generation outside of Manitoba. In the longer-term, the emission factors may change as the emissions impacts will be directly influenced by potential greenhouse gas emission policy changes that may be implemented within the MISO regions.

The below table provides the emissions implications of a high efficient (92% AFUE) natural gas furnace and an electric furnace in an average Manitoba single-detached home. The assumed annual energy consumption values for the below emissions are 1 744 m^3 of natural gas and 16 605 kWh of electricity.

Heating System	**Manitoba** (kg CO_2e / year)	**MISO Region** (kg CO_2e / year)
Natural Gas Furnace	3 313	---
Electric Furnace	---	12 454

Heating an average single-detached home in Manitoba with an electric furnace instead of a natural gas furnace would reduce local emissions in Manitoba by 3 313 kg CO_2e per year; however, it would also increase emissions in the MISO region by 12 454 kg CO_2e per year, resulting in a net overall global increase in emissions of 9 141 kg CO_2e per year.

These emission estimates do not include other lifecycle considerations, such as fuel extraction, processing, and transportation, if considered, the global increase in emissions would be higher.

REFERENCE:

PUB/MH I-128a Attachments Page 213 of 219

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on IFF16-Updated, please indicate the directional change in economic impacts for each of the following:

i. Utility perspective (electric)
ii. Utility perspective (gas)
iii. Customer perspective
iv. Integrated Utility/Customer Perspective
v. Net Provincial Inflow/(Leakage)

RATIONALE FOR QUESTION:

RESPONSE:

MH16-Update includes an increased electric rates forecast and decreased export price forecast when compared to the forecasts used in the fuel switching analysis referenced above. Based on the forecasts informing MH16-Update, below is the estimated directional change in fuel switching economics by perspective.

i. Utility perspective (electric) – With a lower export price forecast and slightly higher electricity rates forecast, it is anticipated that a customer choosing to heat their home with electricity will become more economically favorable from the electric utility perspective than heating with natural gas.

ii. Utility perspective (gas) – As the natural gas rates forecasts have remained relatively unchanged, the economics from the natural gas utility perspective are expected to continue to be significantly negative when a customer chooses electricity over natural gas for space heating.

It is anticipated that from an overall utility perspective (electric and natural gas combined) it would continue to be less economic if a customer chose to heat their home with electricity than if they heated with natural gas.

iii. Customer perspective – With an increase to the electricity rates forecast and a relatively unchanged natural gas rates forecast it is expected that the economic advantage from the customer's perspective of heating their home with natural gas compared to electricity will increase.

iv. Integrated Utility/Customer Perspective – Although the advantage is expected to be lower, it is expected that heating with natural gas will continue to more economic than heating with electricity from an integrated utility/customer perspective even with the lower export price forecast and higher electricity rates forecast.

v. Net Provincial Inflow/(Leakage) – Although the advantage is expected to be lower, it is expected that heating with natural gas will continue to be more economic than heating with electricity from a net provincial perspective even with the lower export price forecast and higher electricity rates forecast.

56

4 NEED FOR NEW RESOURCES TO MEET EXISTING OBLIGATIONS

The need for new resources to meet the expected load requirements is assessed using supply assumptions which include the base supply of power resources including committed resources, and the Manitoba base load forecast net of demand side management (DSM) and export sales requirements. Using the planning criteria, the supply-demand surplus, or deficit is determined for each year for 35 years into the future. The year in which significant persistent deficits begin for either dependable energy or peak capacity is the year that new resources are required.

Table 1 shows the changes in the dates that new resources are needed for both dependable energy and capacity compared to the 2016 Resource Planning Assumptions & Analysis. The variation in the date new resources are needed is due to changes in the load forecast, DSM, and base resource assumptions including allowable import quantities, wind generation, and existing system capabilities.

Subsequent to the completion of the 2016 Resource Planning Assumptions & Analysis, there have been changes in the supply and demand balance which have resulted in Manitoba Hydro updating the supply and demand balance information for the 2016 Integrated Financial Forecast. The updated supply and demand balance information includes a 21 month delay in the in-service date for the Keeyask Generating Station, and the adjustments to the 2016 Electric Load Forecast, and is summarized in Table 1 below.

For the 2017 planning assumptions, the need for new resources is driven by sustained dependable energy shortfall beginning in 2039/40. Resources are required to meet sustained capacity deficits beginning in 2041/42

Table 1: Changes to Supply-Demand Balances

Changes to Dependable Energy (GWh)								
Fiscal Year	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45
System Surplus (Deficit) 2016, No New Resources	423	(157)	(728)	(1,324)	(1,919)	(2,503)	(3,098)	(3,695)
System Surplus (Deficit) 2016 IFF, No New Resources	1,454	961	477	(33)	(540)	(1,038)	(1,546)	(2,055)
System Surplus (Deficit) 2017, No New Resources	783	344	(485)	(470)	(821)	(1,253)	(1,696)	(2,141)

Changes to Winter Peak Capacity (MWs)								
Fiscal Year	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45
System Surplus (Deficit) 2016, No New Resources	133	5	(122)	(141)	(271)	(401)	(530)	(661)
System Surplus (Deficit) 2016 IFF, No New Resources	434	328	222	225	117	8	(100)	(208)
System Surplus (Deficit) 2017, No New Resources	254	157	32	43	(56)	(155)	(254)	(355)

APPENDIX A DEPENDABLE SUPPLY & DEMAND

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

	Fiscal Year		2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2035/36
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Notigi																			
	Manasan																			
	Early Morning																			
	First Rapids																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
3	**Total New Power Resources**	1+2																		
	Base Supply Power Resources																			
	Existing and Committed Hydro		5 105	5 110	5 289	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727
	Existing Thermal																			
	Brandon Coal/ Unit 5																			
	Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	Brandon Units 6-7 SCGT		278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
	Contracted Imports		688	605	605	605	605	605	220	220	220	220	220							
	Proposed Imports													220	220	220	220	220	220	220
	Additional Market Resources																			
	Existing Wind		52	52	52	52	52	52	52	32	32	32	32	32	32	32	32	32	32	28
	Generation Outages Over System Peak		- 15						- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15
	Bipole III Reduced Losses		90	90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4	**Total Base Supply Power Resources**		**6 230**	**6 167**	**6 346**	**6 775**	**6 775**	**6 775**	**6 375**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 351**
5	**Total Power Resources**	3+4	**6 230**	**6 167**	**6 346**	**6 775**	**6 775**	**6 775**	**6 375**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 351**
	Peak Demand																			
	2017 Base Load Forecast		4 794	4 798	4 873	4 894	4 927	4 987	5 059	5 139	5 220	5 299	5 381	5 465	5 552	5 643	5 734	5 826	5 921	6 021
	Less: 2016 DSM Forecast (2017 update)		- 229	- 314	- 396	- 441	- 478	- 512	- 547	- 582	- 617	- 652	- 688	- 722	- 728	- 733	- 739	- 744	- 749	- 754
6	**Manitoba Net Load**		4 565	4 484	4 477	4 453	4 449	4 475	4 513	4 557	4 603	4 646	4 693	4 743	4 824	4 910	4 995	5 083	5 172	5 267
	Contracted Exports		727	945	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385	110	110
	Proposed Exports																			
7	**Total Exports**		727	945	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385	110	110
8	**Total Peak Demand**	6+7	**5 292**	**5 429**	**5 494**	**5 443**	**5 439**	**5 465**	**5 008**	**5 052**	**4 988**	**5 031**	**5 078**	**5 128**	**5 209**	**5 295**	**5 380**	**5 468**	**5 282**	**5 377**
9	Reserves		537	531	531	529	528	532	535	540	545	550	555	561	571	581	592	602	610	621
10	**System Surplus**	5-8-9	**401**	**207**	**321**	**802**	**807**	**778**	**832**	**762**	**822**	**773**	**721**	**665**	**574**	**479**	**383**	**285**	**463**	**352**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

	Fiscal Year		2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52	2052/53
	Power Resources																		
	New Power Resources																		
	New Hydro																		
	Conawapa																		
	Notigi																		
	Manasan																		
	Early Morning																		
	First Rapids																		
1	**Total New Hydro**																		
	New Thermal																		
	SCGT																		
	CCGT																		
2	**Total New Thermal**																		
3	**Total New Power Resources**	1+2																	
	Base Supply Power Resources																		
	Existing and Committed Hydro		5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727
	Existing Thermal																		
	Brandon Coal/ Unit 5																		
	Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	Brandon Units 6-7 SCGT		278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
	Contracted Imports																		
	Proposed Imports		220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
	Additional Market Resources																		
	Existing Wind		28	28	28														
	Generation Outages Over System Peak		- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15
	Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4	**Total Base Supply Power Resources**		**6 351**	**6 351**	**6 351**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**
5	**Total Power Resources**	3+4	**6 351**	**6 351**	**6 351**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**
	Peak Demand																		
	2017 Base Load Forecast		6 021	6 113	6 205	6 297	6 389	6 481	6 573	6 664	6 756	6 848	6 940	7 032	7 124	7 216	7 308	7 399	7 491
	Less: 2016 DSM Forecast (2017 update)		- 754	- 759	- 764	- 769	- 771	- 775	- 778	- 781	- 783	- 786	- 784	- 783	- 782	- 781	- 781	- 780	- 780
6	**Manitoba Net Load**		5 267	5 354	5 441	5 528	5 617	5 706	5 795	5 883	5 973	6 062	6 156	6 249	6 342	6 435	6 527	6 619	6 711
	Contracted Exports		110	110	110	110													
	Proposed Exports																		
7	**Total Exports**		110	110	110	110													
8	**Total Peak Demand**	6+7	**5 377**	**5 464**	**5 551**	**5 638**	**5 617**	**5 706**	**5 795**	**5 883**	**5 973**	**6 062**	**6 156**	**6 249**	**6 342**	**6 435**	**6 527**	**6 619**	**6 711**
9	Reserves		621	632	642	653	662	673	683	694	705	715	727	738	749	760	771	782	793
10	**System Surplus**	5-8-9	**352**	**254**	**157**	**32**	**43**	**- 56**	**- 155**	**- 254**	**- 355**	**- 455**	**- 559**	**- 664**	**- 768**	**- 872**	**- 975**	**-1 079**	**-1 182**

System Firm Summer Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2035/36
Power Resources																			
New Power Resources																			
New Hydro																			
Conawapa																			
Notigi																			
Manasan																			
Early Morning																			
First Rapids																			
1 **Total New Hydro**																			
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
3 **Total New Power Resources**	1+2																		
Base Supply Power Resources																			
Existing and Committed Hydro		5 140	5 144	5 135	5 594	5 760	5 760	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759
Existing Thermal																			
Brandon Coal/ Unit 5																			
Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Brandon Units 6-7 SCGT		228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Contracted Imports																			
Proposed Imports																			
Additional Market Resources																			
Existing Wind		40	40	40	40	40	40	40	25	25	25	25	25	25	25	25	25	25	25
Generation Outages Over Summer Peak								- 15	- 133	- 133	- 133	- 133	- 115	- 115	- 115	- 115	- 115	- 115	- 115
Bipole III Reduced Losses		90	90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**5 531**	**5 535**	**5 526**	**5 975**	**6 141**	**6 141**	**6 126**	**5 992**	**5 992**	**5 992**	**5 992**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**
5 **Total Power Resources**	3+4	**5 531**	**5 535**	**5 526**	**5 975**	**6 141**	**6 141**	**6 126**	**5 992**	**5 992**	**5 992**	**5 992**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**
Peak Demand																			
2017 Base Load Forecast		3 425	3 429	3 499	3 516	3 538	3 583	3 636	3 693	3 751	3 809	3 868	3 929	3 992	4 057	4 122	4 188	4 256	4 327
Less: 2016 DSM Forecast (updated)		- 127	- 164	- 198	- 227	- 257	- 286	- 316	- 346	- 378	- 413	- 449	- 485	- 489	- 494	- 498	- 502	- 506	- 510
6 **Manitoba Net Load**		3 298	3 265	3 301	3 289	3 281	3 298	3 320	3 348	3 373	3 396	3 419	3 444	3 503	3 563	3 624	3 686	3 750	3 817
Contracted Exports		1 469	1 605	1 678	1 650	1 650	1 650	715	715	605	605	605	385	385	385	385	385	110	110
Proposed Exports													220	220	220	220	220	220	220
7 **Total Exports**		1 469	1 605	1 678	1 650	1 650	1 650	715	715	605	605	605	605	605	605	605	605	330	330
8 **Total Peak Demand**	6+7	**4 767**	**4 870**	**4 979**	**4 939**	**4 931**	**4 948**	**4 035**	**4 063**	**3 978**	**4 001**	**4 024**	**4 049**	**4 108**	**4 168**	**4 229**	**4 291**	**4 080**	**4 147**
9 Reserves		401	398	404	403	402	404	397	400	402	405	407	410	417	425	432	439	444	452
10 **System Surplus**	5-8-9	**363**	**267**	**143**	**633**	**808**	**789**	**1 694**	**1 529**	**1 612**	**1 587**	**1 561**	**1 550**	**1 485**	**1 417**	**1 349**	**1 279**	**1 486**	**1 411**

System Firm Summer Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52	2052/53
Power Resources																		
New Power Resources																		
New Hydro																		
Conawapa																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 **Total New Power Resources**	1+2																	
Base Supply Power Resources																		
Existing and Committed Hydro		5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759
Existing Thermal																		
Brandon Coal/ Unit 5																		
Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Brandon Units 6-7 SCGT		228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Contracted Imports																		
Proposed Imports																		
Additional Market Resources																		
Existing Wind		25	22	22														
Generation Outages Over System Peak		- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**6 010**	**6 007**	**6 007**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**
5 **Total Power Resources**	3+4	**6 010**	**6 007**	**6 007**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**
Peak Demand																		
2017 Base Load Forecast		4 327	4 394	4 460	4 526	4 592	4 658	4 725	4 791	4 857	4 923	4 989	5 056	5 122	5 188	5 254	5 320	5 387
Less: 2016 DSM Forecast (updated)		- 510	- 513	- 517	- 521	- 523	- 526	- 529	- 532	- 534	- 537	- 535	- 535	- 534	- 533	- 533	- 533	- 533
6 **Manitoba Net Load**		3 817	3 880	3 942	4 005	4 069	4 132	4 195	4 259	4 323	4 387	4 454	4 521	4 588	4 655	4 721	4 788	4 854
Contracted Exports		110	110	110	110													
Proposed Exports		220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
7 **Total Exports**		330	330	330	330	220	220	220	220	220	220	220	220	220	220	220	220	220
8 **Total Peak Demand**	6+7	**4 147**	**4 210**	**4 272**	**4 335**	**4 289**	**4 352**	**4 415**	**4 479**	**4 543**	**4 607**	**4 674**	**4 741**	**4 808**	**4 875**	**4 941**	**5 008**	**5 074**
9 Reserves		452	460	467	475	481	489	496	504	512	519	527	535	543	551	559	567	575
10 **System Surplus**	5-8-9	**1 411**	**1 337**	**1 267**	**1 176**	**1 215**	**1 144**	**1 073**	**1 002**	**931**	**859**	**784**	**709**	**634**	**559**	**485**	**410**	**336**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

	Fiscal Year		2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
	Power Resources																		
	New Power Resources																		
	New Hydro																		
	Conawapa																		
	Notigi																		
	Manasan																		
	Early Morning																		
	First Rapids																		
1	**Total New Hydro**																		
	New Thermal																		
	SCGT																		
	CCGT																		
2	**Total New Thermal**																		
3	New Wind																		
4	**Total New Power Resources**	1+2+3																	
	Base Supply Power Resources																		
	Existing and Committed Hydro		21 826	21 717	23 005	24 625	24 625	24 615	24 605	24 605	24 595	24 585	24 585	24 575	24 575	24 565	24 555	24 555	24 545
	Existing Thermal																		
	Brandon Coal/ Unit 5																		
	Selkirk Gas		899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899
	Brandon Units 6-7 SCGT		2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343
	Contracted Imports		2 810	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113	1 113	1 113	1 113	186
	Proposed Imports													781	936	936	936	936	936
	Hydro Adjustment		903	844	844	844	844	844	406	307	307	307	307	307	307	307	307	307	307
	Market Purchases		258	1 686	1 500	1 500	1 500	1 500	2 202	2 441	2 053	1 996	2 023	1 889	1 932	1 978	2 023	2 070	2 009
	Existing Wind		781	781	781	781	781	781	781	545	483	483	483	483	483	483	483	483	483
	Bipole III Reduced Losses		101	101	101	177	177	177	177	177	177	177	177	177	177	177	177	177	177
5	**Total Base Supply Power Resources**		**29 920**	**31 873**	**33 162**	**34 857**	**34 857**	**34 847**	**33 733**	**33 367**	**32 906**	**32 839**	**32 866**	**32 722**	**32 765**	**32 801**	**32 836**	**32 883**	**31 884**
6	**Total Power Resources**	4+5	**29 920**	**31 873**	**33 162**	**34 857**	**34 857**	**34 847**	**33 733**	**33 367**	**32 906**	**32 839**	**32 866**	**32 722**	**32 765**	**32 801**	**32 836**	**32 883**	**31 884**

	Manitoba Domestic Load																		
	2017 Base Load Forecast		26 220	26 238	26 766	26 877	27 055	27 389	27 780	28 208	28 641	29 068	29 510	29 962	30 428	30 914	31 399	31 895	32 398
	Construction Power adjustment																		
	Less: 2016 DSM Forecast (updated)		-1 052	-1 368	-1 657	-1 837	-2 006	-2 163	-2 325	-2 482	-2 647	-2 818	-2 993	-3 163	-3 195	-3 227	-3 257	-3 285	-3 311
7	**Manitoba Net Load**		**25 167**	**24 870**	**25 109**	**25 040**	**25 049**	**25 226**	**25 455**	**25 727**	**25 994**	**26 250**	**26 518**	**26 799**	**27 234**	**27 687**	**28 142**	**28 610**	**29 087**
	Contracted Exports		3 410	4 519	5 168	5 054	5 027	5 027	2 744	2 600	2 185	2 102	2 102	1 940	1 940	1 940	1 940	1 940	904
	Proposed Exports													162	162	162	162	162	162
	Less: Adverse Water		- 370	- 370	- 489	- 513	- 513	- 513	- 85										
8	**Total Net Exports**		**3 040**	**4 148**	**4 679**	**4 541**	**4 514**	**4 514**	**2 659**	**2 600**	**2 185**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**1 066**
9	**Total Energy Demand**	7+8	**28 207**	**29 019**	**29 788**	**29 581**	**29 563**	**29 741**	**28 114**	**28 326**	**28 180**	**28 352**	**28 620**	**28 901**	**29 336**	**29 789**	**30 244**	**30 713**	**30 153**

10	**System Surplus**	6-9	**1 713**	**2 855**	**3 374**	**5 276**	**5 294**	**5 106**	**5 619**	**5 041**	**4 727**	**4 487**	**4 246**	**3 820**	**3 430**	**3 011**	**2 592**	**2 170**	**1 732**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52	2052/53
Power Resources																		
New Power Resources																		
New Hydro																		
Conawapa																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 New Wind																		
4 **Total New Power Resources**	1+2+3																	
Base Supply Power Resources																		
Existing and Committed Hydro		24 535	24 535	24 525	24 525	24 515	24 505	24 505	24 495	24 485	24 485	24 475	24 465	24 465	24 455	24 455	24 445	24 435
Existing Thermal																		
Brandon Coal/ Unit 5																		
Selkirk Gas		899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899
Brandon Units 6-7 SCGT		2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343
Contracted Imports																		
Proposed Imports		936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936
Hydro Adjustment		307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307
Market Purchases		2 038	2 084	2 131	2 177	2 226	2 274	2 322	2 370	2 418	2 466	2 516	2 566	2 615	2 664	2 714	2 763	2 812
Existing Wind		467	422	410														
Bipole III Reduced Losses		177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
5 **Total Base Supply Power Resources**		**31 702**	**31 703**	**31 728**	**31 364**	**31 403**	**31 441**	**31 489**	**31 527**	**31 565**	**31 613**	**31 653**	**31 692**	**31 742**	**31 781**	**31 831**	**31 870**	**31 909**
6 **Total Power Resources**	4+5	**31 702**	**31 703**	**31 728**	**31 364**	**31 403**	**31 441**	**31 489**	**31 527**	**31 565**	**31 613**	**31 653**	**31 692**	**31 742**	**31 781**	**31 831**	**31 870**	**31 909**
Manitoba Domestic Load																		
2017 Base Load Forecast		32 930	33 426	33 916	34 408	34 900	35 391	35 883	36 374	36 866	37 358	37 849	38 341	38 832	39 324	39 816	40 307	40 799
Construction Power adjustment																		
Less: 2016 DSM Forecast (updated)		-3 337	-3 364	-3 390	-3 416	-3 426	-3 437	-3 448	-3 459	-3 467	-3 476	-3 471	-3 468	-3 465	-3 463	-3 462	-3 461	-3 461
7 **Manitoba Net Load**		**29 593**	**30 062**	**30 526**	**30 992**	**31 474**	**31 954**	**32 435**	**32 915**	**33 399**	**33 882**	**34 378**	**34 873**	**35 367**	**35 861**	**36 353**	**36 846**	**37 338**
Contracted Exports		696	696	696	696	237	145	145	145	145	145	145	145	145	145	145	145	145
Proposed Exports		162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Less: Adverse Water																		
8 **Total Net Exports**		**858**	**858**	**858**	**858**	**399**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**
9 **Total Energy Demand**	7+8	**30 451**	**30 920**	**31 384**	**31 850**	**31 873**	**32 261**	**32 742**	**33 222**	**33 706**	**34 189**	**34 685**	**35 180**	**35 674**	**36 168**	**36 660**	**37 153**	**37 645**
10 **System Surplus**	6-9	**1 251**	**783**	**344**	**- 485**	**- 470**	**- 821**	**-1 253**	**-1 696**	**-2 141**	**-2 575**	**-3 032**	**-3 487**	**-3 932**	**-4 387**	**-4 830**	**-5 283**	**-5 736**

APPENDIX A: DEPENDABLE SUPPLY & DEMAND

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2015 Planning Assumptions
No New Resources

	Fiscal Year		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
	Power Resources																			
	New Power Resources																			
	New Hydro																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New NUG PPA																			
	Contracted																			
	Proposed			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
3	**Total New NUG PPA**			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
4	**Total New Power Resources**	1+2+3		**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
	Base Supply Power Resources																			
	Existing Hydro		5 172	5 164	5 166	5 171	5 286	5 811	5 802	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797
	Existing Thermal																			
	Brandon Coal - Unit 5		105	105	105	105														
	Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Imports		605	688	688	688	688	605	605	605	605	605	220	220	220	220	220			
	Market Purchases																			
	Additional Market Resources																			
	Bipole III Reduced Losses					90	90	80	80	80	80	80	80	80	80	80	80	80	80	80
5	**Total Base Supply Power Resources**		**6 162**	**6 303**	**6 371**	**6 466**	**6 476**	**6 908**	**6 899**	**6 894**	**6 894**	**6 894**	**6 509**	**6 509**	**6 509**	**6 509**	**6 509**	**6 289**	**6 289**	**6 289**
6	**Total Power Resources**	4+5	**6 162**	**6 312**	**6 380**	**6 475**	**6 485**	**6 917**	**6 908**	**6 903**	**6 903**	**6 903**	**6 518**	**6 518**	**6 518**	**6 518**	**6 518**	**6 298**	**6 298**	**6 298**
	Peak Demand																			
	2015 Base Load Forecast		4 829	4 936	5 000	5 063	5 086	5 210	5 267	5 337	5 406	5 476	5 547	5 619	5 692	5 765	5 840	5 915	6 012	6 112
	Less: 2015 DSM Forecast		- 46	- 89	- 195	- 280	- 369	- 456	- 542	- 585	- 621	- 654	- 685	- 719	- 753	- 788	- 824	- 831	- 837	- 843
7	**Manitoba Net Load**		4 783	4 847	4 805	4 783	4 717	4 754	4 725	4 752	4 785	4 822	4 862	4 900	4 939	4 977	5 016	5 084	5 175	5 269
	Contracted Exports		572	789	789	614	614	779	908	880	880	880	385	385	275	275	275	275	275	275
	Proposed Exports							110	110	110	110	110	110	110	110	110	110	110	110	110
8	**Total Exports**		572	789	789	614	614	889	1 018	990	990	990	495	495	385	385	385	385	385	385
9	**Total Peak Demand**	7+8	**5 355**	**5 636**	**5 594**	**5 397**	**5 331**	**5 643**	**5 743**	**5 742**	**5 775**	**5 812**	**5 357**	**5 395**	**5 324**	**5 362**	**5 401**	**5 469**	**5 560**	**5 654**
10	Reserves		574	582	577	574	566	571	567	570	574	579	583	588	593	597	602	610	621	632
11	**System Surplus**	6-9-10	**233**	**94**	**209**	**504**	**588**	**703**	**598**	**591**	**554**	**512**	**578**	**535**	**601**	**559**	**515**	**219**	**117**	**12**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2015 Planning Assumptions
No New Resources

Fiscal Year		2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51
Power Resources																			
New Power Resources																			
New Hydro																			
1 **Total New Hydro**																			
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New NUG PPA																			
Contracted																			
Proposed		9	9	9															
3 **Total New NUG PPA**		9	9	9															
4 **Total New Power Resources**	1+2+3	**9**	**9**	**9**															
Base Supply Power Resources																			
Existing Hydro		5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports																			
Market Purchases																			
Additional Market Resources																			
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
5 **Total Base Supply Power Resources**		**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**
6 **Total Power Resources**	4+5	**6 298**	**6 298**	**6 298**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**
Peak Demand																			
2015 Base Load Forecast		6 220	6 341	6 462	6 582	6 703	6 824	6 944	7 065	7 185	7 306	7 427	7 547	7 668	7 788	7 909	8 030	8 150	8 271
Less: 2015 DSM Forecast		- 849	- 854	- 860	- 865	- 871	- 877	- 883	- 887	- 890	- 894	- 897	- 900	- 901	- 903	- 904	- 906	- 908	- 910
7 **Manitoba Net Load**		5 371	5 487	5 602	5 717	5 832	5 947	6 061	6 178	6 295	6 412	6 530	6 647	6 767	6 885	7 005	7 124	7 242	7 361
Contracted Exports		275	275																
Proposed Exports		110	110	110	110	110	110	110											
8 **Total Exports**		385	385	110	110	110	110	110											
9 **Total Peak Demand**	7+8	**5 756**	**5 872**	**5 712**	**5 827**	**5 942**	**6 057**	**6 171**	**6 178**	**6 295**	**6 412**	**6 530**	**6 647**	**6 767**	**6 885**	**7 005**	**7 124**	**7 242**	**7 361**
10 Reserves		645	658	672	686	700	714	727	741	755	769	784	798	812	826	841	855	869	883
11 **System Surplus**	6-9-10	**- 103**	**- 232**	**- 86**	**- 224**	**- 353**	**- 482**	**- 609**	**- 630**	**- 761**	**- 892**	**-1 025**	**-1 156**	**-1 290**	**-1 422**	**-1 557**	**-1 690**	**-1 822**	**-1 955**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2015 Planning Assumptions
No New Resources

	Fiscal Year		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
	Power Resources																			
	New Power Resources																			
	New Hydro																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Nug PPA																			
	Contracted																			
	Proposed			48	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
3	**Total New Nug PPA**			**48**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4		**48**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
	Base Supply Power Resources																			
	Existing Hydro		21 924	21 892	21 878	21 880	22 356	24 790	24 778	24 746	24 746	24 736	24 726	24 726	24 716	24 706	24 706	24 696	24 696	24 686
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	592													
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports		2 485	2 809	2 809	2 809	2 809	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113	1 113
	Proposed Imports																			
	Hydro Adjustment		784	903	903	903	903	844	844	844	844	844	406	307	307	307	307	70		
	Market Purchases		582	258	258	258	258	957	1 050	1 050	1 050	1 050	2 417	2 688	2 688	2 688	2 688	3 440	3 624	3 624
	Additional Market Resources																			
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Bipole III Reduced Losses					101	101	177	177	177	177	177	177	177	177	177	177	177	177	177
6	**Total Base Supply Power Resources**		**30 664**	**30 751**	**30 737**	**30 840**	**31 097**	**34 348**	**34 615**	**34 583**	**34 583**	**34 573**	**34 125**	**34 026**	**34 016**	**34 006**	**34 006**	**33 729**	**33 688**	**33 678**
7	**Total Power Resources**	5+6	**30 664**	**30 799**	**30 834**	**30 937**	**31 194**	**34 445**	**34 712**	**34 680**	**34 680**	**34 670**	**34 221**	**34 122**	**34 112**	**34 102**	**34 102**	**33 826**	**33 785**	**33 775**
	Manitoba Domestic Load																			
	2015 Base Load Forecast		26 145	26 792	27 126	27 486	27 600	28 449	28 786	29 197	29 590	29 999	30 408	30 823	31 243	31 664	32 094	32 531	33 101	33 684
	Non-Committed Construction Power		110	110	110	110	110	83												
	Less: 2015 DSM Forecast		- 217	- 412	- 852	-1 231	-1 652	-1 940	-2 231	-2 399	-2 557	-2 704	-2 844	-2 995	-3 156	-3 325	-3 498	-3 534	-3 566	-3 598
8	**Manitoba Net Load**		**26 038**	**26 490**	**26 384**	**26 365**	**26 058**	**26 592**	**26 555**	**26 798**	**27 033**	**27 295**	**27 564**	**27 828**	**28 087**	**28 339**	**28 596**	**28 997**	**29 535**	**30 086**
	Contracted Exports		2 739	3 388	3 502	3 289	3 246	3 964	4 604	4 503	4 476	4 476	2 193	2 049	1 634	1 551	1 551	1 389	1 389	1 389
	Proposed Exports							459	551	551	551	551	551	551	551	551	551	551	551	551
	Less: Adverse Water		- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 512	- 512	- 512	- 85							
9	**Total Net Exports**		**2 430**	**3 018**	**3 132**	**2 919**	**2 876**	**4 053**	**4 666**	**4 542**	**4 515**	**4 515**	**2 659**	**2 600**	**2 185**	**2 102**	**2 102**	**1 940**	**1 940**	**1 940**
10	**Total Energy Demand**	8+9	**28 468**	**29 508**	**29 516**	**29 284**	**28 934**	**30 645**	**31 221**	**31 340**	**31 548**	**31 810**	**30 223**	**30 428**	**30 272**	**30 441**	**30 698**	**30 937**	**31 475**	**32 026**
11	**System Surplus**	7-10	**2 197**	**1 291**	**1 318**	**1 653**	**2 260**	**3 800**	**3 491**	**3 340**	**3 132**	**2 860**	**3 998**	**3 694**	**3 840**	**3 661**	**3 404**	**2 889**	**2 310**	**1 749**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2015 Planning Assumptions
No New Resources

Fiscal Year	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51
Power Resources																		
New Power Resources																		
New Hydro																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
New Nug PPA																		
Contracted																		
Proposed	97	97	97	48														
3 **Total New Nug PPA**	**97**	**97**	**97**	**48**														
4 New Wind																		
5 **Total New Power Resources** 1+2+3+4	**97**	**97**	**97**	**48**														
Base Supply Power Resources																		
Existing Hydro	24 676	24 676	24 666	24 656	24 656	24 646	24 646	24 636	24 626	24 626	24 616	24 606	24 606	24 596	24 586	24 586	24 576	24 576
Existing Thermal																		
Brandon Coal - Unit 5																		
Selkirk Gas	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
Contracted Imports	1 113	1 113	186															
Proposed Imports																		
Hydro Adjustment																		
Market Purchases	3 625	3 625	3 790	3 834	3 901	3 967	4 033	3 643	3 619	3 687	3 755	3 824	3 893	3 961	4 030	4 098	4 167	4 236
Additional Market Resources																		
Existing Wind	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
Bipole III Reduced Losses	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
6 **Total Base Supply Power Resources**	**33 669**	**33 669**	**32 897**	**32 745**	**32 812**	**32 868**	**32 934**	**32 534**	**32 500**	**32 568**	**32 626**	**32 685**	**32 754**	**32 812**	**32 871**	**32 939**	**32 998**	**33 067**
7 **Total Power Resources** 5+6	**33 766**	**33 766**	**32 993**	**32 793**	**32 812**	**32 868**	**32 934**	**32 534**	**32 500**	**32 568**	**32 626**	**32 685**	**32 754**	**32 812**	**32 871**	**32 939**	**32 998**	**33 067**
Manitoba Domestic Load																		
2015 Base Load Forecast	34 317	35 011	35 705	36 400	37 094	37 788	38 482	39 176	39 870	40 564	41 259	41 953	42 647	43 341	44 035	44 729	45 424	46 118
Non-Committed Construction Power																		
Less: 2015 DSM Forecast	-3 628	-3 655	-3 684	-3 713	-3 742	-3 771	-3 802	-3 816	-3 828	-3 840	-3 849	-3 860	-3 866	-3 874	-3 882	-3 890	-3 899	-3 907
8 **Manitoba Net Load**	**30 689**	**31 356**	**32 021**	**32 687**	**33 352**	**34 017**	**34 680**	**35 360**	**36 042**	**36 724**	**37 410**	**38 093**	**38 781**	**39 467**	**40 153**	**40 839**	**41 525**	**42 211**
Contracted Exports	1 389	1 389	353	145	145	145	145	145	145	145	145	145	145	145	145	145	145	146
Proposed Exports	551	551	551	551	551	551	551	92										
Less: Adverse Water																		
9 **Total Net Exports**	**1 940**	**1 940**	**904**	**696**	**696**	**696**	**696**	**237**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**146**
10 **Total Energy Demand** 8+9	**32 629**	**33 296**	**32 925**	**33 383**	**34 048**	**34 713**	**35 376**	**35 597**	**36 187**	**36 869**	**37 555**	**38 238**	**38 926**	**39 612**	**40 298**	**40 984**	**41 670**	**42 357**
11 **System Surplus** 7-10	**1 137**	**470**	**69**	**- 590**	**-1 236**	**-1 845**	**-2 442**	**-3 063**	**-3 687**	**-4 301**	**-4 929**	**-5 553**	**-6 172**	**-6 800**	**-7 427**	**-8 045**	**-8 672**	**-9 290**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2015 Planning Assumptions
Market Resources for Capacity and Simple Cycle Gas Turbine Generation

Fiscal Year		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Power Resources																			
New Power Resources																			
New Hydro																			
1 **Total New Hydro**																			
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New NUG PPA																			
Contracted																			
Proposed			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
3 **Total New NUG PPA**			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
4 **Total New Power Resources**	1+2+3		**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
Base Supply Power Resources																			
Existing Hydro		5 172	5 164	5 166	5 171	5 286	5 811	5 802	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797
Existing Thermal																			
Brandon Coal - Unit 5		105	105	105	105														
Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports		605	688	688	688	688	605	605	605	605	605	220	220	220	220	220			
Market Purchases																			
Additional Market Resources																			
Bipole III Reduced Losses					90	90	80	80	80	80	80	80	80	80	80	80	80	80	80
5 **Total Base Supply Power Resources**		**6 162**	**6 303**	**6 371**	**6 466**	**6 476**	**6 908**	**6 899**	**6 894**	**6 894**	**6 894**	**6 509**	**6 509**	**6 509**	**6 509**	**6 509**	**6 289**	**6 289**	**6 289**
6 **Total Power Resources**	4+5	**6 162**	**6 312**	**6 380**	**6 475**	**6 485**	**6 917**	**6 908**	**6 903**	**6 903**	**6 903**	**6 518**	**6 518**	**6 518**	**6 518**	**6 518**	**6 298**	**6 298**	**6 298**
Peak Demand																			
2015 Base Load Forecast		4 829	4 936	5 000	5 063	5 086	5 210	5 267	5 337	5 406	5 476	5 547	5 619	5 692	5 765	5 840	5 915	6 012	6 112
Less: 2015 DSM Forecast		- 46	- 89	- 195	- 280	- 369	- 456	- 542	- 585	- 621	- 654	- 685	- 719	- 753	- 788	- 824	- 831	- 837	- 843
7 **Manitoba Net Load**		4 783	4 847	4 805	4 783	4 717	4 754	4 725	4 752	4 785	4 822	4 862	4 900	4 939	4 977	5 016	5 084	5 175	5 269
Contracted Exports		572	789	789	614	614	779	908	880	880	880	385	385	275	275	275	275	275	275
Proposed Exports							110	110	110	110	110	110	110	110	110	110	110	110	110
8 **Total Exports**		572	789	789	614	614	889	1 018	990	990	990	495	495	385	385	385	385	385	385
9 **Total Peak Demand**	7+8	**5 355**	**5 636**	**5 594**	**5 397**	**5 331**	**5 643**	**5 743**	**5 742**	**5 775**	**5 812**	**5 357**	**5 395**	**5 324**	**5 362**	**5 401**	**5 469**	**5 560**	**5 654**
10 Reserves		574	582	577	574	566	571	567	570	574	579	583	588	593	597	602	610	621	632
11 **System Surplus**	6-9-10	**233**	**94**	**209**	**504**	**588**	**703**	**598**	**591**	**554**	**512**	**578**	**535**	**601**	**559**	**515**	**219**	**117**	**12**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2015 Planning Assumptions
Market Resources for Capacity and Simple Cycle Gas Turbine Generation

Fiscal Year		2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51
Power Resources																			
New Power Resources																			
New Hydro																			
1 **Total New Hydro**																			
New Thermal																			
SCGT					245	490	490	735	735	980	980	1 225	1 225	1 470	1 470	1 715	1 715	1 960	1 960
CCGT																			
2 **Total New Thermal**					245	490	490	735	735	980	980	1 225	1 225	1 470	1 470	1 715	1 715	1 960	1 960
New NUG PPA																			
Contracted																			
Proposed		9	9	9															
3 **Total New NUG PPA**		9	9	9															
4 **Total New Power Resources**	1+2+3	**9**	**9**	**9**	**245**	**490**	**490**	**735**	**735**	**980**	**980**	**1 225**	**1 225**	**1 470**	**1 470**	**1 715**	**1 715**	**1 960**	**1 960**
Base Supply Power Resources																			
Existing Hydro		5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports																			
Market Purchases																			
Additional Market Resources		103	232	86															
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
5 **Total Base Supply Power Resources**		**6 392**	**6 521**	**6 375**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**
6 **Total Power Resources**	4+5	**6 401**	**6 530**	**6 384**	**6 534**	**6 779**	**6 779**	**7 024**	**7 024**	**7 269**	**7 269**	**7 514**	**7 514**	**7 759**	**7 759**	**8 004**	**8 004**	**8 249**	**8 249**
Peak Demand																			
2015 Base Load Forecast		6 220	6 341	6 462	6 582	6 703	6 824	6 944	7 065	7 185	7 306	7 427	7 547	7 668	7 788	7 909	8 030	8 150	8 271
Less: 2015 DSM Forecast		- 849	- 854	- 860	- 865	- 871	- 877	- 883	- 887	- 890	- 894	- 897	- 900	- 901	- 903	- 904	- 906	- 908	- 910
7 **Manitoba Net Load**		5 371	5 487	5 602	5 717	5 832	5 947	6 061	6 178	6 295	6 412	6 530	6 647	6 767	6 885	7 005	7 124	7 242	7 361
Contracted Exports		275	275																
Proposed Exports		110	110	110	110	110	110	110											
8 **Total Exports**		385	385	110	110	110	110	110											
9 **Total Peak Demand**	7+8	**5 756**	**5 872**	**5 712**	**5 827**	**5 942**	**6 057**	**6 171**	**6 178**	**6 295**	**6 412**	**6 530**	**6 647**	**6 767**	**6 885**	**7 005**	**7 124**	**7 242**	**7 361**
10 Reserves		645	658	672	686	700	714	727	741	755	769	784	798	812	826	841	855	869	883
11 System Surplus	6-9-10				**21**	**137**	**8**	**126**	**105**	**219**	**88**	**200**	**69**	**180**	**48**	**158**	**25**	**138**	**5**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2015 Planning Assumptions
Market Resources for Capacity and Simple Cycle Gas Turbine Generation

	Fiscal Year		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
	Power Resources																			
	New Power Resources																			
	New Hydro																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
	New Nug PPA																			
	Contracted																			
	Proposed			48	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
3	**Total New Nug PPA**			**48**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
4	New Wind																			
5	**Total New Power Resources**	1+2+3+4		**48**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
	Base Supply Power Resources																			
	Existing Hydro		21 924	21 892	21 878	21 880	22 356	24 790	24 778	24 746	24 746	24 736	24 726	24 726	24 716	24 706	24 706	24 696	24 696	24 686
	Existing Thermal																			
	Brandon Coal - Unit 5		811	811	811	811	592													
	Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports		2 485	2 809	2 809	2 809	2 809	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113	1 113
	Proposed Imports																			
	Hydro Adjustment		784	903	903	903	903	844	844	844	844	844	406	307	307	307	307	70		
	Market Purchases		582	258	258	258	258	957	1 050	1 050	1 050	1 050	2 417	2 688	2 688	2 688	2 688	3 440	3 624	3 624
	Additional Market Resources																			
	Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
	Bipole III Reduced Losses					101	101	177	177	177	177	177	177	177	177	177	177	177	177	177
6	**Total Base Supply Power Resources**		**30 664**	**30 751**	**30 737**	**30 840**	**31 097**	**34 348**	**34 615**	**34 583**	**34 583**	**34 573**	**34 125**	**34 026**	**34 016**	**34 006**	**34 006**	**33 729**	**33 688**	**33 678**
7	**Total Power Resources**	5+6	**30 664**	**30 799**	**30 834**	**30 937**	**31 194**	**34 445**	**34 712**	**34 680**	**34 680**	**34 670**	**34 221**	**34 122**	**34 112**	**34 102**	**34 102**	**33 826**	**33 785**	**33 775**
	Manitoba Domestic Load																			
	2015 Base Load Forecast		26 145	26 792	27 126	27 486	27 600	28 449	28 786	29 197	29 590	29 999	30 408	30 823	31 243	31 664	32 094	32 531	33 101	33 684
	Non-Committed Construction Power		110	110	110	110	110	83												
	Less: 2015 DSM Forecast		- 217	- 412	- 852	-1 231	-1 652	-1 940	-2 231	-2 399	-2 557	-2 704	-2 844	-2 995	-3 156	-3 325	-3 498	-3 534	-3 566	-3 598
8	**Manitoba Net Load**		**26 038**	**26 490**	**26 384**	**26 365**	**26 058**	**26 592**	**26 555**	**26 798**	**27 033**	**27 295**	**27 564**	**27 828**	**28 087**	**28 339**	**28 596**	**28 997**	**29 535**	**30 086**
	Contracted Exports		2 739	3 388	3 502	3 289	3 246	3 964	4 604	4 503	4 476	4 476	2 193	2 049	1 634	1 551	1 551	1 389	1 389	1 389
	Proposed Exports							459	551	551	551	551	551	551	551	551	551	551	551	551
	Less: Adverse Water		- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 512	- 512	- 512	- 85							
9	**Total Net Exports**		**2 430**	**3 018**	**3 132**	**2 919**	**2 876**	**4 053**	**4 666**	**4 542**	**4 515**	**4 515**	**2 659**	**2 600**	**2 185**	**2 102**	**2 102**	**1 940**	**1 940**	**1 940**
10	**Total Energy Demand**	8+9	**28 468**	**29 508**	**29 516**	**29 284**	**28 934**	**30 645**	**31 221**	**31 340**	**31 548**	**31 810**	**30 223**	**30 428**	**30 272**	**30 441**	**30 698**	**30 937**	**31 475**	**32 026**
11	**System Surplus**	7-10	**2 197**	**1 291**	**1 318**	**1 653**	**2 260**	**3 800**	**3 491**	**3 340**	**3 132**	**2 860**	**3 998**	**3 694**	**3 840**	**3 661**	**3 404**	**2 889**	**2 310**	**1 749**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2015 Planning Assumptions
Market Resources for Capacity and Simple Cycle Gas Turbine Generation

Fiscal Year		2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51
Power Resources																			
New Power Resources																			
New Hydro																			
1 **Total New Hydro**																			
New Thermal																			
SCGT					1 857	3 714	3 714	5 571	5 571	7 428	7 428	9 285	9 285	11 142	11 142	12 999	12 999	14 856	14 856
CCGT																			
2 **Total New Thermal**					**1 857**	**3 714**	**3 714**	**5 571**	**5 571**	**7 428**	**7 428**	**9 285**	**9 285**	**11 142**	**11 142**	**12 999**	**12 999**	**14 856**	**14 856**
New Nug PPA																			
Contracted																			
Proposed		97	97	97	48														
3 **Total New Nug PPA**		**97**	**97**	**97**	**48**														
4 New Wind																			
5 **Total New Power Resources**	1+2+3+4	**97**	**97**	**97**	**1 905**	**3 714**	**3 714**	**5 571**	**5 571**	**7 428**	**7 428**	**9 285**	**9 285**	**11 142**	**11 142**	**12 999**	**12 999**	**14 856**	**14 856**
Base Supply Power Resources																			
Existing Hydro		24 676	24 676	24 666	24 656	24 656	24 646	24 646	24 636	24 626	24 626	24 616	24 606	24 606	24 596	24 586	24 586	24 576	24 576
Existing Thermal																			
Brandon Coal - Unit 5																			
Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
Contracted Imports		1 113	1 113	186															
Proposed Imports																			
Hydro Adjustment		173	341	139															
Market Purchases		3 166	2 592	3 406	3 834	3 901	3 967	4 033	3 643	3 619	3 687	3 755	3 824	3 893	3 961	4 030	4 098	4 167	4 236
Additional Market Resources		459	1 033	383															
Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
Bipole III Reduced Losses		177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
6 **Total Base Supply Power Resources**		**33 842**	**34 010**	**33 035**	**32 745**	**32 812**	**32 868**	**32 934**	**32 534**	**32 500**	**32 568**	**32 626**	**32 685**	**32 754**	**32 812**	**32 871**	**32 939**	**32 998**	**33 067**
7 **Total Power Resources**	5+6	**33 939**	**34 107**	**33 131**	**34 650**	**36 526**	**36 582**	**38 505**	**38 105**	**39 928**	**39 996**	**41 911**	**41 970**	**43 896**	**43 954**	**45 870**	**45 938**	**47 854**	**47 923**
Manitoba Domestic Load																			
2015 Base Load Forecast		34 317	35 011	35 705	36 400	37 094	37 788	38 482	39 176	39 870	40 564	41 259	41 953	42 647	43 341	44 035	44 729	45 424	46 118
Non-Committed Construction Power																			
Less: 2015 DSM Forecast		-3 628	-3 655	-3 684	-3 713	-3 742	-3 771	-3 802	-3 816	-3 828	-3 840	-3 849	-3 860	-3 866	-3 874	-3 882	-3 890	-3 899	-3 907
8 **Manitoba Net Load**		**30 689**	**31 356**	**32 021**	**32 687**	**33 352**	**34 017**	**34 680**	**35 360**	**36 042**	**36 724**	**37 410**	**38 093**	**38 781**	**39 467**	**40 153**	**40 839**	**41 525**	**42 211**
Contracted Exports		1 389	1 389	353	145	145	145	145	145	145	145	145	145	145	145	145	145	145	146
Proposed Exports		551	551	551	551	551	551	551	92										
Less: Adverse Water																			
9 **Total Net Exports**		**1 940**	**1 940**	**904**	**696**	**696**	**696**	**696**	**237**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**146**
10 **Total Energy Demand**	8+9	**32 629**	**33 296**	**32 925**	**33 383**	**34 048**	**34 713**	**35 376**	**35 597**	**36 187**	**36 869**	**37 555**	**38 238**	**38 926**	**39 612**	**40 298**	**40 984**	**41 670**	**42 357**
11 **System Surplus**	7-10	**1 310**	**811**	**207**	**1 267**	**2 478**	**1 869**	**3 129**	**2 508**	**3 741**	**3 127**	**4 356**	**3 732**	**4 970**	**4 342**	**5 572**	**4 954**	**6 184**	**5 566**

In his Evidence, Mr. Bowman states that coal should be allocated to domestic customers only on account of legislation contained in Bill 15. While Manitoba Hydro agrees technically with Mr. Bowman's perspective, his recommendation adds unnecessary complexity particularly in view of the small magnitude of the dollars involved regarding Manitoba Hydro's investment in Coal Generation.

It would appear that Mr. Bowman may have reached that same conclusion during the workshops: *"But as I was discussing with the – the chairman earlier, one (1) of the natures of Hydro's system is that that role is not only different for every plant, it's different for every water flow for every plant. And by the time all is said and done, if ever there were a utility that you could take almost all of the plant and say, That functions as one (1) block, and I'm not going to try to pierce that veil and figure out what everything's doing, it's probably Manitoba Hydro because droughts look different than floods look different than average."* (Intervener Workshop, June 21, 2016, Transcript pages 148).

It was precisely this perspective that led Manitoba Hydro to the implementation of the pooled approach in PCOSS14-Amended. Manitoba Hydro believes that the pooled approach to generation assets is reasonable and pragmatically considers the balance between additional complexity and materiality related to Coal Generation. Manitoba Hydro is prepared on this basis, and within the context of its broader framework proposed for the treatment of exports, to include these costs in the generation pool to be allocated to both Domestic and Dependable export sales.

Similarly, in the absence of any demonstrated capacity benefits, Manitoba Hydro can conceptually support Mr. Bowman's recommendation to treat Wind resources as 100% Energy related. However, again given the added complexity introduced by creating an additional generation pool and the materiality of impact on COS results, Manitoba Hydro views it as more appropriate to continue to incorporate Wind resources into the overall Generation pool.

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Figure 7.12 Historical Water Supply

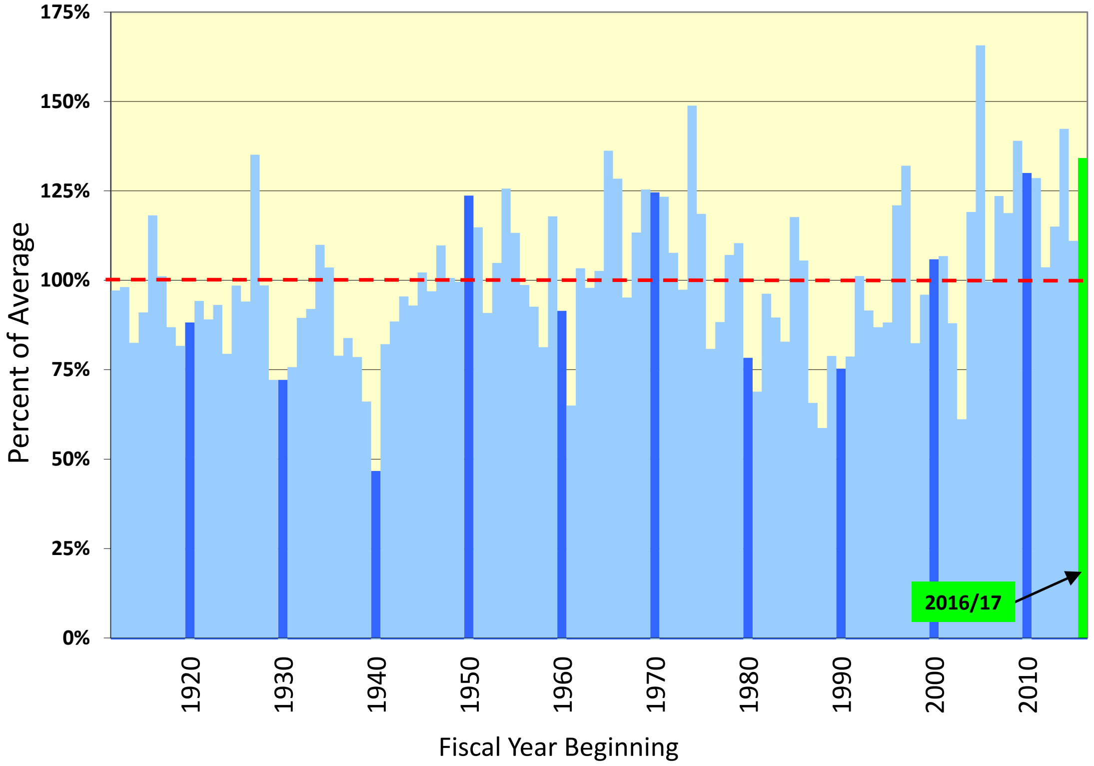


Figure 7.13 below shows historical daily inflows beginning in 1977, with inflows for 2016 and 2017 and the average shown as highlighted. Of note are the near record high inflows experienced since mid-September 2016 as a result of widespread rains falling across most of the basin which sustained inflows through the winter.

Chart (b) - Energy in Storage

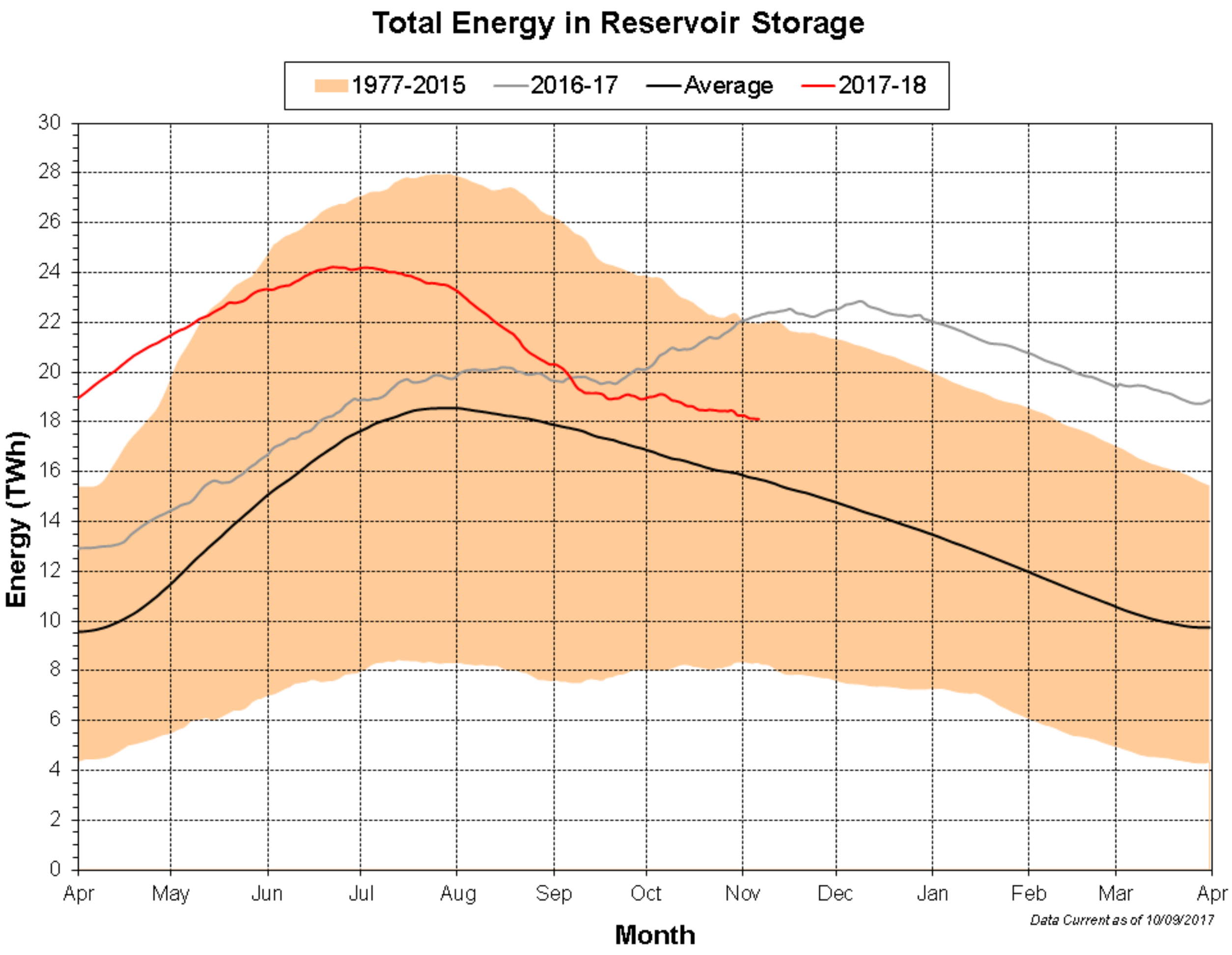
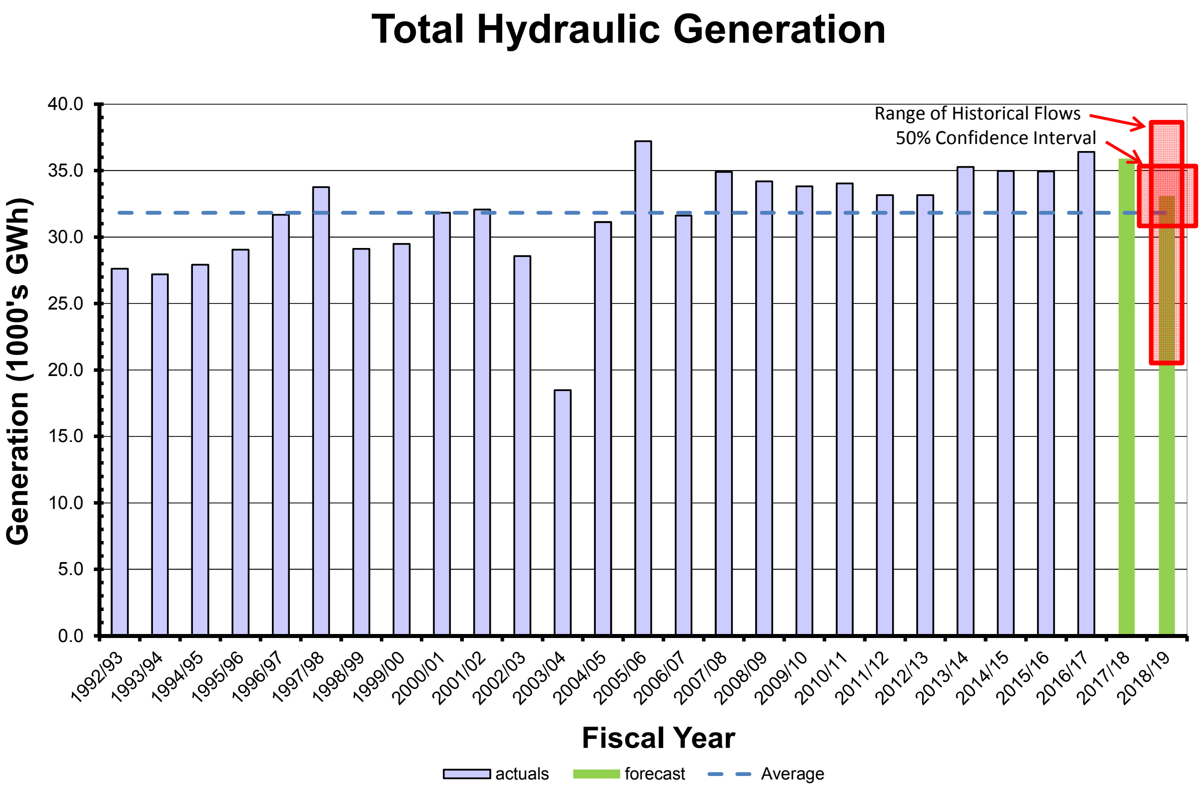


Figure 6. Total Hydraulic Generation



Due to the very wet conditions, hydraulic generation is forecast to be 36.0 TWh in 2017/18 in the MH16 Update, a 1.7 TWh increase over MH16. Thermal generation and purchased energy are forecast to be 1.3 TWh, a 350 GWh reduction over MH16. Net supply is forecast to be 37.3 TWh, a 1.4 TWh increase compared to MH16.

The MH16 Update forecast hydraulic generation for 2018/19 benefits from the expected high storage carry-over from 2017/18. Hydraulic generation is forecast to be 32.8 TWh, thermal generation and energy purchases 2.1 TWh, for net supply of 34.9 TWh. Compared to MH16, this is a 2.0 TWh increase, 167 GWh decrease and 1.8 TWh increase, respectively.

Figure 7 shows a comparison of MH16 and MH16 Update extraprovincial revenues (net of generation costs). Favourable water conditions, discussed above, result in $120 million in higher extraprovincial revenues over the two years 2017/18 and 2018/19 relative to MH16. Over the 10-year period to 2026/27, MH16 Update extraprovincial

REFERENCE:

Tab 2, Pages 3, lines 9-11
PUB MFR 25

PREAMBLE TO IR (IF ANY):

The Application states “Prolonged above average water flow and declining interest rates have helped mitigate some of Manitoba Hydro’s financial deterioration but such conditions cannot be assumed to repeat”.

QUESTION:

a) Please confirm that neither IFF14, IFF15, IFF16 nor the current IFF16-Updated assumed that above average water flow conditions would repeat during the forecast years.
b) Please confirm that for IFF16 (and IFF16-Updated) Manitoba Hydro has changed its methodology for forecasting water flows in the second year of the forecast and that the change results in lower hydro production and lower net income for that year.
c) What is the impact on the IFF16 net income forecast for 2017/18 of the change in methodology/assumptions regarding water flows in that year?
d) For IFF16-Updated, is 2017/18 or 2018/19 considered the “second year” of the forecast?
e) What is the impact on net income in the second year of the IFF16-Updated forecast of the change in methodology/assumptions regarding water flows in that year?

RATIONALE FOR QUESTION:

To clarify Manitoba Hydro’s stated reasons for needing successive annual rate increases of 7.9%.

RESPONSE:

a) None of IFF14, IFF15, IFF16 or MH16 Update assumed continued persistence in above average water flow conditions occurring in the second year of the forecast. The IFF assumes that each of the historic flow conditions could occur in the second and subsequent years.

The first year of the forecast is influenced by prevailing flow conditions at the time the forecast was prepared transitioning to average over time. This practice was used in IFF16 and MH16-Update and is unchanged from the approach used in earlier IFFs.

b) Manitoba Hydro confirms that, for IFF16 and MH16-Update, it has changed its methodology for year two where it now uses the full record historic flows for the second year of the forecast (referred to as "Multi-flow") rather a single median scenario ("Median").

This methodology better reflects all possible revenue and cost outcomes reflecting the historic range of potential inflows within the context of expected starting storage conditions.

As indicated in Table 1 below, the change does not necessarily result in a negative impact on net revenue due to the effect of starting storage conditions. Table 1 provides the forecast methodology impact on net revenues, the details of when year 2 forecasts were prepared, and starting conditions at the beginning of those forecast years.

Table 1. Definition of Year 2 and impact on forecast net revenue due to methodology change.

IFF	Year 2	Date Year 2 Simulations Prepared	Expected storage condition at the start of Year 2	Methodology Impact on Net Revenue in Year 2 (Median – Multi-flow)
IFF16	2017/18	Feb 2017	Well above average	$5M
MH16-Update	2018/19	Jun 2017	Near average	$(6.3M)

IFF16 was prepared in February of 2017 when Manitoba Hydro expected storage conditions would be well above average at the start of 2017/18, year two of IFF16. With high starting storage conditions, more water is spilled in simulations using high inflows from the historic record than would be the case if starting storage conditions were closer to average. This effect is not as pronounced in a simulation using a median flow scenario.

In MH16-Update, the expected starting storage on April 1 2018 is closer to average. In simulating high flow years of the historic hydrology, the inflows are more ‘usable’ because storage is available to manage the high inflows. Under these storage conditions, average hydro generation and net revenues from the Multi-flow forecast are higher than the forecast using the median scenario.

Please refer to PUB/MH I-19d for a comparison of forecast hydraulic generation for the Median vs. Multi-flow methods for the second year of IFF16 and MH16-Updated.

c) Please see the response to part b).

d) Please see the response to part b).

e) Please see the response to part b).

REFERENCE:

Appendix 3.1 IFF16 Page 16; Tab 7 Pages 17 and 29 of 30; Tab 6 Page 8 of 55

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please clarify the water flow record used for IFF16: as stated on page 16 of IFF16, which is a 102 year record from 1912/13 to 2013/14, or as stated on Tab 6 page 8 and Tab 7 page 17, which is a 104 year record from 1912/13 to 2015/16. If IFF16 is based on a 102 year record, please explain why the water flow record has not been updated.

RATIONALE FOR QUESTION:

RESPONSE:

The water flow record used in IFF16 for 2017/18 was the 104 year flow record (1912/13 to 2015/16) and not the 102 year record as stated in Appendix 3.1 (page 16).

For 2018/19 and subsequent years, the projections are determined by using flow conditions for the past 102 years (1912/13 to 2013/14). At the time of simulation the inclusion of over 100 flow cases was judged to provide a sufficient representation of the non-linear distribution of net revenue with respect to the range of hydraulic inflows, such that it was deemed unnecessary to add the additional flow cases to the simulation for longer term planning purposes.

REFERENCE:

Appendix 3.1 IFF16 Page 16; Tab 7 Pages 17 and 29 of 30; Tab 6 Page 8 of 55

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please clarify the methodology now used for the second year of the IFF: are the financial results based on a single inflow condition which is an average of all inflow records (per IFF16 page 16) or the average of financial consequences from the full water flow record (per Tab 7 page 29 lines 17-19)?

c) Please provide Manitoba Hydro's original rationale for using the median of 80 years of inflow conditions in the second year of its financial forecast, and specifically address why the 80-year median was used instead of an 80-year mean or full water flow record mean. Please also explain why a single inflow condition was used instead of the financial consequences of inflow conditions.

RATIONALE FOR QUESTION:

RESPONSE:

b) The second year of IFF16 reflects the average of all revenues and average of all costs for each of the water flow years on record from 1912/13 through 2015/16. It is not a reflection of the financial outcome from a single flow case such as median water flow year or an average water flow year.

c) Prior to IFF16, the second year of the IFF was based on a single flow year that was calibrated to produce median hydraulic generation on the Manitoba Hydro system.

Use of a mean flow is not appropriate because it does not produce mean net revenues. This is because hydraulic generation is not symmetrically distributed, because the conversion of water supply to generation is not linear, and because the costs of serving load in a low water year far exceed the incremental export sales in a high water year.

For example, the distribution of hydraulic generation does not match that of water supply as once river flows get too high, generation is capped and actually decreases as flows increase.

Historically, expected flows were used for the balance of the current year and median flows were assumed for the next two years including the test year. The median flow event was deemed to be the most likely to represent Manitoba Hydro's financial outcome for the test year(s). Twenty years ago, the median flow assumption was reduced from two years to one year. However because of the asymmetric net export revenue relationship, the median assumption underestimated Manitoba Hydro's long term revenue requirements.

Manitoba Hydro's operational modeling capability has advanced to the point where it is now practical to do a multi-flow analysis (the average of 104 river flow cases) for the test year. Each of these are at a much greater level of detail than the analyses used in subsequent years of the IFF. For example, test year forecasts are prepared using weekly time steps, greater generating station detail and other detailed operating information such as actual maintenance outage plans.

REFERENCE:

Appendix 3.1 IFF16 Page 16; Tab 7 Pages 17 and 29 of 30; Tab 6 Page 8 of 55

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please provide two tables for 1) IFF16 (2017/18) and 2) IFF16 Update (2018/19) showing the export revenues, fuel & power purchases, and net export revenues for the second forecast year based on the previous methodology (80-year median) and based on the new methodology. In these tables, please show the annual system inflows and hydraulic energy forecasted under each methodology.

RATIONALE FOR QUESTION:

RESPONSE:

Table 1: 2017/18 Net Extraprovincial Revenue, Inflows and Hydraulic Energy

	Average[1] (Multiflow)	**Median**	**Difference: Median less Multiflow**
Extra-provincial Revenue ($M)	454.2	455.3	1.1
Fuel & Power Purchased ($M)	135.4	131.9	(3.5)
Water Rentals & Assessments ($M)	124.1	123.8	(0.4)
Net Extra-provincial Revenue ($M)	**$ 194.6**	**$ 199.6**	**$ 5.0**
Hydraulic Generation (GWh)	34,270	34,218	(52)
Energy from System Inflows (GWh)[2]	see note	32,500	N/A

[1] Average of revenues minus costs derived from 104 flow cases (Multiflow).

[2] Energy from System Inflows is not directly comparable to hydraulic generation. Please see response to COALITION/MH I-9a for an explanation of energy from inflows and a table of estimated energy from inflows for the period 1912/13 through 2016/17.

Table 2: 2018/19 Net Extraprovincial Revenue, Inflows and Hydraulic Energy

	Average[1] (Multiflow)	**Median**	**Difference: Median less Multiflow**
Extra-provincial Revenue ($Million)	469.2	456.9	(12.3)
Fuel & Power Purchased ($Million)	140.0	136.9	(3.1)
Water Rentals & Assessments ($Million)	120.0	117.1	(2.9)
Net Extra-provincial Revenue ($Million)	**$ 209.2**	**$ 202.9**	**$ (6.3)**
Hydraulic Generation (GWh)	32,799	31,955	(844)
Energy from System Inflows (GWh)[2]	see note	32,500	N/A

[1] Average of revenues minus costs derived from 104 flow cases (Multiflow).

[2] Energy from System Inflows is not directly comparable to hydraulic generation. Please see response to COALITION/MH I-9a for an explanation of energy from inflows and a table of energy from inflows for the period 1912/13 through 2016/17.

REFERENCE:

PUB/MH I-20; Coalition/MH I-62; 2010/11 GRA Transcript page 2446; Supplement to Tab 3

PREAMBLE TO IR (IF ANY):

PUB/MH I-20d shows hydraulic generation in 2017/18 under the average (multiflow) methodology exceeding that under the previous median methodology by 52 GWh. For 2018/19, the average methodology produces greater hydraulic generation than the previous median methodology by 844 GWh.

At the 2010/11 GRA, Manitoba Hydro stated that median flows always produce more hydraulic energy than average flows.

QUESTION:

a) Please reconcile the higher hydraulic generation under average (multiflow) conditions compared with median flow conditions shown in PUB/MH I-19d with Manitoba Hydro's previous statements at the 2010/11 GRA on transcript page 2446.

b) Please explain the hydraulic assumptions underpinning the hydraulic generation forecast for 2017/18 in IFF16-Updated. For example, Supplement to Tab 3 page 9 assumes "expected inflows", but are these average or median inflows? As of what date are the reservoir conditions incorporated in the forecast?

RATIONALE FOR QUESTION:

RESPONSE:

a) As explained in PUB/MH I-19c, the median flow scenario ("Median") was a flow scenario calibrated to produce median hydraulic generation. This flow scenario was prepared in the early 1990s and has not been updated over time. The referenced testimony from the 2010/11 GRA addressed the difference in hydraulic generation between the Median flow scenario and the average hydraulic generation based on a simulation of 94 flow years (i.e. 1912/13 through 2006/07). Inflows have been above average to well above average in every year since 2003/04. Adding recent historic flow values to the record has resulted in an increase in average hydraulic generation relative to the static Median generation value.

Also note that the starting storage conditions can impact the difference in forecast hydraulic generation between a given single flow year (such as the Median flow scenario) and the average hydraulic generation from a simulation of the historic flow years. This is explained further in Coalition/MH I-62a-e.

b) The hydraulic generation forecast for 2017/18 in MH16-Update was based on a single ‘expected’ inflow scenario based on conditions as of June 14, 2017.

As normal practice in planning Manitoba Hydro’s reservoir operations, each week a new “Expected” system inflow forecast starts at observed flows and consists of projected flows for the remainder of the year based on knowledge of antecedent inflow and basin conditions leading up to the date the forecast is prepared. The word “Expected” is used in the statistical sense as the “Expected” value is the result of a sub basin regression analysis where the antecedent conditions are used as the independent variable. In addition, where upstream reservoir operators regulate the inflow of water into Manitoba, Manitoba Hydro’s “Expected” scenario includes the expected regulation impact. As a result the “Expected” scenario is not the same as the Median scenario, average flows, or a set of historic flow years (i.e. “Multi-flow”).

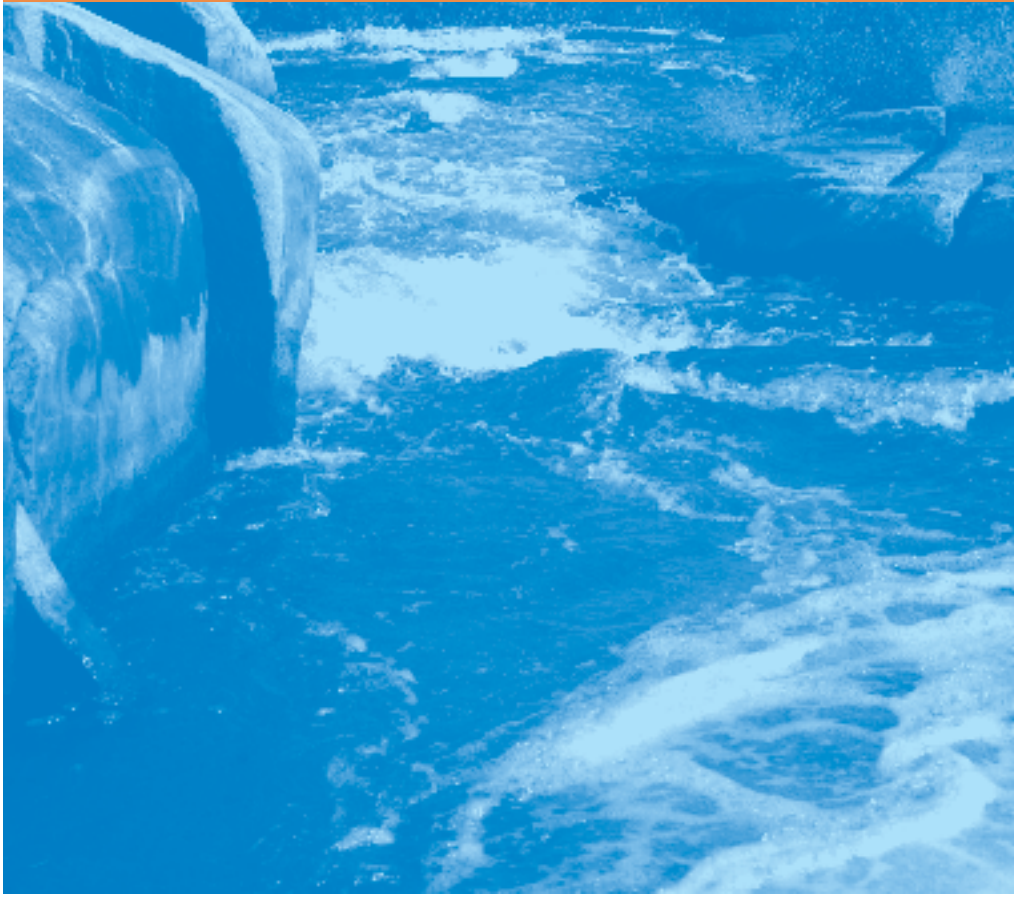
For a detailed discussion of how the expected system inflow forecast is prepared, please refer to transcripts pages 5571-5584 from the 2010/11 Risk Review where Mr. Cormie explains the use of antecedent flows to predict system flows for the remainder of the current year.

The simulations used in the forecast started on June 1, 2017 and incorporated starting reservoir storage levels for that date.

The Manitoba Hydro-Electric Board

Quarterly Report

for the six months ended
September 30, 2017



Report from **The Chair of the Board** and by **The President and Chief Executive Officer**

Financial Overview

Manitoba Hydro's consolidated net loss was $89 million for the first six months of the 2017-18 fiscal year compared to a net loss of $72 million for the same period last year. The increase in the net loss is primarily attributable to restructuring costs driven by the implementation of a significant cost reduction program. Excluding the restructuring expenses, net loss would have been $45 million, an improvement of $24 million over the prior year. The improvement is mostly attributable to favourable water conditions which led to a $32 million improvement in extraprovincial revenues (net of power purchase and water rental expenses) along with $9 million in growth in Manitoba electricity volumes. Higher finance costs and depreciation and amortization expense offset part of these gains. The cost of natural gas is a flow through cost passed onto customers through rates approved by the Public Utilities Board (PUB) and therefore is not a driver for the increase in net loss compared to the prior year.

The consolidated net loss was comprised of a $66 million loss in the electricity segment, a $26 million loss in the natural gas segment, a $2 million net profit in other segments and a $1 million profit impact in adjustments and eliminations.

Manitoba Hydro has seen a significant deterioration in its profit outlook for the 2017-18 fiscal year. The corporation is now forecasting consolidated net income for the year of approximately $40 million. This represents a 44% decrease from 2016-17 net income of $71 million. It also represents almost an 80% drop from our outlook for net income from a reforecast filed with the Public Utilities Board in July. The decrease in forecast is due to the PUB's decision to deny the corporation's request for a 7.9% rate increase as at August 1, 2017, a continuation of weak opportunity export prices, a relatively dry summer impacting water flow conditions and higher financing costs. The forecast assumes average water flow conditions and normal winter weather.

Electric Segment

Revenues from electricity sales within Manitoba totaled $629 million for the six-month period, which was $9 million or 2% higher than the same period last year. The increase in domestic revenue was primarily attributable to an increase in average usage and customer growth, partially offset by weather impacts. Extraprovincial revenues of $275 million were $28 million or 11% higher than the same period last year reflecting higher dependable sales volumes predominantly as a result of higher generation due to favourable water conditions along with modestly higher export prices on opportunity sales. Energy sold in the export market was 6.9 billion kilowatt-hours compared to 6.3 billion kilowatt-hours sold in the same period last year. Other revenues of $15 million were $3 million or 25% higher than the same period last year due to an increase in billable projects for third parties.

Expenses attributable to electricity operations, including the net movement in regulatory deferral balances, totaled $993 million for the six-month period. This represented an increase of $55 million or 6% as compared to the same period last year. The increase was primarily due to a $50 million increase in other expenses, an $8 million increase in net finance expense and a $6 million increase in depreciation and amortization. The increase in other expenses was primarily due to $42 million in restructuring charges associated with the voluntary departure program which launched in April 2017. The increase in net finance expense was primarily the result of foreign exchange losses. The increase in depreciation and amortization was primarily due to new additions to plant being placed into service.

The net loss before net movement in regulatory balances is $113 million. After considering the net movement of $40 million in the regulatory deferral balances, there is a net loss of $73 million of which $66 million is attributable to Manitoba Hydro and $7 million is attributable to non-controlling interest. The non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first six months of the 2017-18 fiscal year.

Expenditures for capital construction for the six-month period amounted to $1 437 million compared to $1 347 million for the same period last year. Expenditures for the current period included $582 million related to construction of the Keeyask project and $573 million for the Bipole III Reliability Project. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The corporation also incurred $31 million for electric demand side management programs.

Natural Gas Segment

The net loss in the natural gas segment was $26 million for the six-month period compared to a $24 million net loss for the same period last year. The increase in the net loss is primarily due to restructuring costs and warmer weather in the first quarter. Delivered gas volumes were 530 million cubic metres compared to 609 million cubic metres for the same period last year.

Expenses attributable to natural gas operations excluding cost of gas sold amounted to $75 million compared to $73 million for the same period last year.

The net loss before net movement in regulatory balances is $39 million. After considering the net movement of $13 million in the regulatory balances, there is a net loss of $26 million.

Capital expenditures in the natural gas segment were $18 million for the current six-month period compared to $26 million for the same period last year. Capital expenditures are related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province. The corporation also incurred $5 million for gas demand side management programs.

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REFERENCE:

PUB/MH I-45; Coalition/MH I-8

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the table in PUB/MH I-45 (Figure 4.4) adding the forecast retained earnings for each year and for each sensitivity. That is, show both the change in retained earnings as well as the resulting retained earnings.

RATIONALE FOR QUESTION:

RESPONSE:

PUB/MH I-45 (Figure 4.4) - Key Variable Sensitivity Impacts to Retained Earnings has been updated below to show the forecast retained earnings for each year and for each sensitivity. The table included in PUB/MH I-45 (Figure 4.4) has also been restated to correct the year in the "Lowest Equity Ratio in 10 Yr Risk Scenario" column.

Key Variable Sensitivity Impacts to MH16 Update with Interim Retained Earnings										Lowest Equity Ratio in 10 yr Risk Scenario	Incremental Annual Electric Rate Increase/(Decrease) Required (2019/20 - 2027/28)
	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28		
MH16 Update with Interim	**3 258**	**3 606**	**4 124**	**4 557**	**4 969**	**5 498**	**5 987**	**6 564**	**7 214**	**14% (2020)**	
Sensitivities: Incremental Increases/(Decrease) in Retained Earnings											
Low Domestic Load Growth	(20)	(48)	(84)	(133)	(195)	(265)	(338)	(418)	(504)	14% (2020)	0.40%
High Domestic Load Growth	18	47	82	128	184	249	318	397	484	14% (2020)	-0.38%
+ 1% Interest	(31)	(75)	(139)	(248)	(367)	(488)	(614)	(747)	(885)	14% (2020)	0.67%
- 1% Interest	29	71	132	233	346	459	567	686	814	14% (2019)	-0.68%
C$/US$ Down 0.10 (C$ Strengthening)	8	14	13	(16)	(65)	(116)	(157)	(203)	(252)	15% (2020)	0.20%
C$/US$ Up 0.10 (C$ Weakening)	(8)	(13)	(10)	18	66	117	158	202	250	14% (2020)	-0.19%
Low Export Price	(19)	(42)	(68)	(117)	(161)	(205)	(287)	(377)	(483)	14% (2020)	0.38%
High Export Price	41	103	183	322	495	689	930	1 203	1 519	14% (2019)	-1.26%
5 Year Drought (starting in 2019/20)	(349)	(758)	(929)	(1 175)	(1 388)					12% (2021)	1.29%
+ 1% Rate Increase in 2018/19	34	54	78	103	129	157	187	220	257	15% (2020)	-0.21%
- 1% Rate Increase in 2018/19	(35)	(55)	(78)	(105)	(136)	(170)	(205)	(241)	(280)	14% (2020)	0.23%
$1B in Capital Overruns	4	6	(31)	(108)	(187)	(267)	(349)	(435)	(525)	14% (2020)	0.43%
Capital Down $100 million/year	11	30	57	94	139	191	250	324	414	15% (2019)	-0.34%
Capital Up $100 million/year	(11)	(30)	(58)	(97)	(147)	(204)	(269)	(347)	(438)	14% (2020)	0.35%
Sensitivities: Total Retained Earnings											
Low Domestic Load Growth	3 237	3 559	4 040	4 424	4 774	5 234	5 649	6 146	6 710		
High Domestic Load Growth	3 275	3 653	4 206	4 685	5 153	5 747	6 305	6 960	7 697		
+ 1% Interest	3 227	3 531	3 984	4 309	4 601	5 011	5 374	5 817	6 329		
- 1% Interest	3 286	3 677	4 256	4 790	5 315	5 958	6 554	7 250	8 028		
C$/US$ Down 0.10 (C$ Strengthening)	3 266	3 620	4 136	4 541	4 904	5 383	5 830	6 361	6 962		
C$/US$ Up 0.10 (C$ Weakening)	3 249	3 593	4 114	4 576	5 035	5 615	6 145	6 766	7 464		
Low Export Price	3 239	3 564	4 056	4 441	4 807	5 293	5 700	6 187	6 730		
High Export Price	3 298	3 710	4 306	4 879	5 464	6 187	6 917	7 767	8 733		
5 Year Drought (starting in 2019/20)	2 909	2 849	3 195	3 382	3 581						
+ 1% Rate Increase in 2018/19	3 292	3 661	4 202	4 661	5 098	5 656	6 174	6 784	7 471		
- 1% Rate Increase in 2018/19	3 223	3 551	4 046	4 452	4 832	5 329	5 782	6 322	6 934		
$1B in Capital Overruns	3 261	3 613	4 092	4 449	4 782	5 232	5 638	6 129	6 688		
Capital Down $100 million/year	3 269	3 636	4 181	4 652	5 107	5 689	6 237	6 888	7 628		
Capital Up $100 million/year	3 246	3 576	4 065	4 460	4 822	5 295	5 718	6 217	6 776		

REFERENCE:

Appendix 3.1 IFF16 Page 30; Tab 4 Page 8 of 34

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide four IFF scenarios including financial ratios assuming 5 year and 7 year drought conditions, beginning in 2019/20 and in 2022/23 (post-Keeyask in service).

RATIONALE FOR QUESTION:

RESPONSE:

The following table compares the above drought sensitivities to the MH16 Update with Interim base forecast to determine the impacts to retained earnings. Financial statements including financial ratios for the four drought scenarios above have been also provided below.

Cumulative Impact to MH16 Update with Interim Retained Earnings

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
5 Year Drought (starting in 2019/20)	(349)	(758)	(929)	(1 175)	(1 388)					
7 Year Drought (starting in 2019/20)	(154)	(244)	(411)	(716)	(1 358)	(1 672)	(1 817)			
5 Year Drought (starting in 2022/23)				(274)	(680)	(882)	(1 159)	(1 407)		
7 Year Drought (starting in 2022/23)				(142)	(252)	(455)	(810)	(1 492)	(1 892)	(2 059)

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
5 Year Drought starting in 2019/20
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES								
General Consumers								
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542
additional*	0	37	179	315	458	619	789	973
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27
Extraprovincial	460	514	469	281	409	580	596	632
Other	28	30	31	31	33	33	34	34
	1 907	2 008	2 246	2 259	2 517	2 856	3 040	3 207
EXPENSES								
Operating and Administrative	536	518	501	526	525	523	536	547
Finance Expense	608	587	677	749	837	918	1 164	1 198
Finance Income	(17)	(17)	(21)	(29)	(35)	(34)	(39)	(16)
Depreciation and Amortization	375	396	471	515	555	597	689	714
Water Rentals and Assessments	131	130	120	76	76	100	103	108
Fuel and Power Purchased	132	124	140	382	420	195	179	152
Capital and Other Taxes	119	132	145	154	161	165	174	175
Other Expenses	60	116	109	481	94	92	71	64
Corporate Allocation	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 864	2 643	2 565	2 886	2 950
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(606)	(126)	291	154	257
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)
Non-recurring Gain	20	-	-	-	-	-	-	-
Net Income	41	85	209	(141)	(55)	355	197	210
Net Income Attributable to:								
Manitoba Hydro before Non-recurring Item	33	93	211	(144)	(60)	346	187	198
Non-recurring Gain	20	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**(144)**	**(60)**	**346**	**187**	**198**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11
	41	85	209	(141)	(55)	355	197	210
* Additional General Consumers Revenue								
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%
Financial Ratios								
Equity	16%	15%	14%	13%	12%	13%	13%	14%
EBITDA Interest Coverage	1.51	1.54	1.71	1.39	1.47	1.84	1.78	1.85
Capital Coverage	1.53	1.40	1.48	0.80	1.09	2.00	1.78	1.98

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
5 Year Drought starting in 2019/20
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024
ASSETS								
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454
Current and Other Assets	1 773	1 915	2 269	2 550	2 616	1 819	1 806	1 809
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 505	30 108	30 000	30 227	30 180
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241
	21 733	24 839	27 774	29 616	31 290	31 246	31 516	31 421
LIABILITIES AND EQUITY								
Long-Term Debt	15 725	18 141	21 376	22 589	23 794	23 650	24 874	24 359
Current and Other Liabilities	3 204	3 643	3 046	3 816	4 361	4 147	3 029	3 183
Provisions	70	50	49	48	46	45	43	42
Deferred Revenue	450	465	491	520	542	551	561	571
BPIII Reserve Account	196	347	346	266	186	106	27	(0)
Retained Earnings	2 749	2 842	3 053	2 909	2 849	3 195	3 382	3 581
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(364)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 567	31 242	31 197	31 467	31 372
Regulatory Deferral Balance	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 616	31 290	31 246	31 516	31 421

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT

5 Year Drought starting in 2019/20

(In Millions of Dollars)

For the year ended March 31	ACTUAL							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES								
Cash Receipts from Customers	1 901	2 152	2 233	2 167	2 425	2 764	2 948	3 168
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(1 075)	(1 115)	(915)	(918)	(932)
Interest Paid	(553)	(531)	(635)	(703)	(779)	(870)	(1 110)	(1 170)
Interest Received	17	5	12	22	26	19	9	8
	810	734	767	412	556	998	928	1 074
FINANCING ACTIVITIES								
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 560	2 590	990	1 560	(10)
Sinking Fund Withdrawals	146	0	0	120	318	813	182	54
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)
	1 987	3 051	2 588	2 320	1 604	425	612	(251)
INVESTING ACTIVITIES								
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(248)	(261)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 245)	(1 056)
Net Increase (Decrease) in Cash	(309)	(145)	74	35	14	(407)	295	(233)
Cash at Beginning of Year	943	634	488	562	597	611	205	500
Cash at End of Year	634	488	562	597	611	205	500	266

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
7 Year Drought starting in 2019/20
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
REVENUES										
General Consumers										
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567
additional*	0	37	179	315	458	619	789	973	1 094	1 158
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	0	0
Extraprovincial	460	514	469	306	476	563	560	525	583	583
Other	28	30	31	31	33	33	34	34	35	35
	1 907	2 008	2 246	2 283	2 583	2 839	3 005	3 101	3 265	3 342
EXPENSES										
Operating and Administrative	536	518	501	508	512	523	536	574	559	571
Finance Expense	608	587	677	747	825	895	1 140	1 176	1 183	1 158
Finance Income	(17)	(17)	(21)	(29)	(35)	(34)	(39)	(12)	(15)	(15)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739
Water Rentals and Assessments	131	130	120	88	101	98	93	76	103	122
Fuel and Power Purchased	132	124	140	220	167	197	235	497	190	119
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 694	2 390	2 543	2 909	3 272	2 997	2 948
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(411)	193	295	96	(172)	268	395
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	54	264	359	139	(219)	218	346
Net Income Attributable to:										
Manitoba Hydro before Non-recurring Item	33	93	211	51	259	350	129	(231)	215	344
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**51**	**259**	**350**	**129**	**(231)**	**215**	**344**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2
	41	85	209	54	264	359	139	(219)	218	346
* Additional General Consumers Revenue										
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%
Financial Ratios										
Equity	16%	15%	14%	14%	14%	15%	14%	14%	15%	16%
EBITDA Interest Coverage	1.51	1.54	1.71	1.58	1.76	1.86	1.74	1.50	1.88	2.03
Capital Coverage	1.53	1.40	1.48	1.17	1.70	2.01	1.67	1.19	1.83	1.97

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
7 Year Drought starting in 2019/20
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ASSETS										
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414
Current and Other Assets	1 773	1 915	2 269	2 543	2 524	1 935	1 663	1 639	1 769	1 680
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 498	30 016	30 116	30 084	30 009	30 081	29 944
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143
	21 733	24 839	27 774	29 609	31 198	31 362	31 372	31 251	31 273	31 087
LIABILITIES AND EQUITY										
Long-Term Debt	15 725	18 141	21 376	22 389	23 194	23 250	24 268	24 154	23 666	22 604
Current and Other Liabilities	3 204	3 643	3 046	3 814	4 355	4 145	3 026	3 182	3 467	3 988
Provisions	70	50	49	48	46	45	43	42	41	40
Deferred Revenue	450	465	491	520	542	551	561	571	582	593
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 104	3 362	3 713	3 842	3 611	3 826	4 170
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(358)	(357)	(356)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 560	31 149	31 313	31 324	31 202	31 224	31 038
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 609	31 198	31 362	31 372	31 251	31 273	31 087

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
7 Year Drought starting in 2019/20
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 901	2 152	2 233	2 192	2 491	2 746	2 912	3 062	3 252	3 330
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(907)	(875)	(917)	(965)	(1 273)	(976)	(935)
Interest Paid	(553)	(531)	(635)	(703)	(770)	(844)	(1 087)	(1 146)	(1 157)	(1 138)
Interest Received	17	5	12	22	26	20	8	4	8	7
	810	734	767	605	871	1 005	869	647	1 127	1 263
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 190	1 190	1 360	390	190	150
Sinking Fund Withdrawals	146	0	0	120	318	813	182	50	344	149
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)
	1 987	3 051	2 588	2 120	1 204	625	412	145	117	(421)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(244)	(255)	(264)	(258)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 241)	(1 050)	(1 064)	(1 072)
Net Increase (Decrease) in Cash	(309)	(145)	74	28	(71)	(199)	40	(258)	180	(229)
Cash at Beginning of Year	943	634	488	562	590	519	320	360	102	282
Cash at End of Year	634	488	562	590	519	320	360	102	282	52

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
5 Year Drought starting in 2022/23
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
General Consumers											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	0	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	0	0	0
Extraprovincial	460	514	469	421	568	694	562	525	630	439	483
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 675	2 970	3 006	3 101	3 312	3 198	3 326
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	547	559	571	583
Finance Expense	608	587	677	744	817	881	1 119	1 155	1 146	1 122	1 113
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(38)	(14)	(14)	(15)	(17)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	94	85	111	106	111
Fuel and Power Purchased	132	124	140	158	165	156	229	302	154	159	149
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 654	2 391	2 506	2 883	3 036	2 931	2 935	2 949
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(256)	284	464	123	64	380	262	377
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	209	355	528	166	17	331	214	332
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	206	350	519	156	5	328	212	329
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**206**	**350**	**519**	**156**	**5**	**328**	**212**	**329**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	209	355	528	166	17	331	214	332
* Additional General Consumers Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	16%	16%	18%	18%	20%
EBITDA Interest Coverage	1.51	1.54	1.71	1.73	1.84	2.02	1.78	1.71	2.01	1.94	2.07
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.35	1.72	1.62	2.01	1.77	1.92

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
5 Year Drought starting in 2022/23
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 499	2 571	1 950	1 702	1 712	1 751	1 730	2 000
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 453	30 062	30 130	30 123	30 083	30 063	29 994	30 224
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 774	29 564	31 245	31 376	31 412	31 324	31 255	31 137	31 322
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 874	23 566	22 878	22 017	22 859
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 145	3 024	3 178	3 459	3 980	2 984
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 259	3 608	4 127	4 283	4 289	4 616	4 828	5 157
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(370)	(369)	(368)	(368)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 516	31 196	31 328	31 363	31 275	31 206	31 088	31 273
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 564	31 245	31 376	31 412	31 324	31 255	31 137	31 322

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
5 Year Drought starting in 2022/23
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 583	2 878	2 914	3 062	3 299	3 185	3 313
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(869)	(885)	(894)	(960)	(1 059)	(948)	(959)	(965)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(830)	(1 068)	(1 128)	(1 124)	(1 103)	(1 090)
Interest Received	17	5	12	22	26	20	7	6	7	8	10
	810	734	767	760	962	1 173	894	881	1 235	1 131	1 268
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 360	190	(10)	350	990
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	339	142	236
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 987	3 051	2 588	1 920	1 204	425	412	(59)	(87)	(228)	43
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(251)	(257)	(250)	(251)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 237)	(1 046)	(1 057)	(1 064)	(1 089)
Net Increase (Decrease) in Cash	(309)	(145)	74	(17)	20	(231)	69	(224)	91	(160)	223
Cash at Beginning of Year	943	634	488	562	545	566	335	404	180	271	111
Cash at End of Year	634	488	562	545	566	335	404	180	271	111	333

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
7 Year Drought starting in 2022/23
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES													
General Consumers													
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583	1 599	1 614
additional*	0	37	179	315	458	619	789	973	1 094	1 158	1 224	1 294	1 364
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	0	0	0	0	0
Extraprovincial	460	514	469	421	568	694	633	671	619	390	293	351	580
Other	28	30	31	31	33	33	34	34	35	35	36	36	37
	1 907	2 008	2 246	2 398	2 675	2 970	3 077	3 247	3 301	3 150	3 136	3 280	3 595
EXPENSES													
Operating and Administrative	536	518	501	511	513	524	536	547	559	571	596	595	607
Finance Expense	608	587	677	744	817	881	1 119	1 150	1 134	1 103	1 099	1 100	1 083
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(40)	(18)	(19)	(15)	(16)	(15)	(23)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752	765	776
Water Rentals and Assessments	131	130	120	110	113	117	109	114	109	97	80	103	122
Fuel and Power Purchased	132	124	140	158	165	156	155	132	163	217	422	172	126
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	175	176	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76	79	84
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 654	2 391	2 506	2 822	2 887	2 921	2 965	3 193	2 983	2 961
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(256)	284	464	255	360	380	184	(57)	297	634
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)	(44)	(40)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	209	355	528	298	313	330	136	(102)	254	594
Net Income Attributable to:													
Manitoba Hydro before Non-recurring Item	33	93	211	206	350	519	288	301	327	134	(105)	250	589
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**206**	**350**	**519**	**288**	**301**	**327**	**134**	**(105)**	**250**	**589**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3	4	5
	41	85	209	209	355	528	298	313	330	136	(102)	254	594
* Additional General Consumers Revenue													
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%	80.95%	84.57%
Financial Ratios													
Equity	16%	15%	14%	14%	15%	17%	16%	18%	19%	20%	19%	20%	23%
EBITDA Interest Coverage	1.51	1.54	1.71	1.73	1.84	2.02	1.90	1.97	2.02	1.89	1.69	2.02	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.35	1.97	2.16	2.01	1.64	1.27	1.80	2.23

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
7 Year Drought starting in 2022/23
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS													
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945	33 553	34 299
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)	(6 906)	(7 603)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732	26 647	26 696
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411	493	454
Current and Other Assets	1 773	1 915	2 269	2 499	2 571	1 950	1 834	1 940	1 979	1 679	1 719	2 147	2 786
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081	1 040	1 001
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 453	30 062	30 130	30 255	30 311	30 291	29 943	29 943	30 327	30 938
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098	1 055	1 014
	21 733	24 839	27 774	29 564	31 245	31 376	31 544	31 552	31 482	31 086	31 041	31 381	31 952
LIABILITIES AND EQUITY													
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 874	23 366	22 678	21 617	22 659	22 791	20 414
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 145	3 024	3 178	3 459	3 980	2 987	2 935	5 286
Provisions	70	50	49	48	46	45	43	42	41	40	39	38	37
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603	615	624
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 259	3 608	4 127	4 416	4 717	5 044	5 177	5 072	5 322	5 911
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(370)	(369)	(368)	(368)	(368)	(368)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 516	31 196	31 328	31 495	31 503	31 433	31 038	30 992	31 332	31 903
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 564	31 245	31 376	31 544	31 552	31 482	31 086	31 041	31 381	31 952

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
7 Year Drought starting in 2022/23
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**												
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OPERATING ACTIVITIES													
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 583	2 878	2 985	3 208	3 288	3 137	3 123	3 267	3 582
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(869)	(885)	(894)	(900)	(918)	(955)	(1 008)	(1 221)	(993)	(978)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(830)	(1 068)	(1 122)	(1 111)	(1 084)	(1 073)	(1 079)	(1 078)
Interest Received	17	5	12	22	26	20	9	10	12	8	9	13	28
	810	734	767	760	962	1 173	1 026	1 177	1 235	1 053	838	1 208	1 553
FINANCING ACTIVITIES													
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 360	(10)	(10)	150	1 190	190	(10)
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	339	140	234	150	60
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)	(150)	(60)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)	(5)	(5)
	1 987	3 051	2 588	1 920	1 204	425	412	(259)	(87)	(430)	241	185	(15)
INVESTING ACTIVITIES													
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)	(767)	(798)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(251)	(255)	(247)	(247)	(248)	(251)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)	(80)	(74)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 237)	(1 046)	(1 055)	(1 062)	(1 085)	(1 095)	(1 124)
Net Increase (Decrease) in Cash	(309)	(145)	74	(17)	20	(231)	201	(128)	93	(438)	(6)	298	415
Cash at Beginning of Year	943	634	488	562	545	566	335	536	408	500	62	56	354
Cash at End of Year	634	488	562	545	566	335	536	408	500	62	56	354	768

REFERENCE:

PUB/MH I-48

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table that compares the drought sensitivities to the MH16 Update with Interim assuming 5 year and 7 year drought conditions, beginning in 2019/20 and in 2022/23 (post-Keeyask in service), based on MH16-Updated with Interim, but with 3.95% rate increases beginning 2018/19 and continuing through the five and seven year periods. Please include the forecast retained earnings for each year as well as the change in retained earnings compared to MH16-U with Interim. That is, please re-file the table in PUB/MH I-48 except based on 3.95% rate increases and also showing the forecast retained earnings in each year. Please also provide the four IFF scenarios including financial ratios that support the table.

RATIONALE FOR QUESTION:

RESPONSE:

The following tables compare the 5 and 7 year drought sensitivities to (1) MH16 Update with Interim but with 3.95% rate increases beginning in 2018/19 and continuing through the five and seven year periods, and (2) MH16 Update with Interim and 7.90% rate increases to 2023/24, followed by 4.54% and 2.00% thereafter (as provided in PUB/MH-I-48b).

Financial statements including financial ratios for the four drought scenarios with 3.95% base rate increases have also been provided below.

Figure 1

Cumulative Impact to MH16 Update with Interim and 3.95% Retained Earnings

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Base Scenario: Total Retained Earnings										
MH16 Update with Interim and 3.95%	3 056	3 181	3 375	3 368	3 210	3 106	2 955	2 879	2 877	2 992
Sensitivities: Total Retained Earnings										
5 Year Drought (starting in 2019/20)	2 708	2 424	2 446	2 195	1 825					
7 Year Drought (starting in 2019/20)	2 902	2 937	2 964	2 653	1 849	1 422	1 115			
5 Year Drought (starting in 2022/23)				3 093	2 529	2 213	1 774	1 444		
7 Year Drought (starting in 2022/23)				3 227	2 959	2 649	2 134	1 372	959	888
Sensitivities: Incremental Increase/(Decrease) in Retained Earnings										
5 Year Drought (starting in 2019/20)	(348)	(757)	(929)	(1 173)	(1 386)					
7 Year Drought (starting in 2019/20)	(154)	(244)	(411)	(716)	(1 361)	(1 684)	(1 840)			
5 Year Drought (starting in 2022/23)				(275)	(682)	(893)	(1 181)	(1 435)		
7 Year Drought (starting in 2022/23)				(141)	(251)	(457)	(821)	(1 507)	(1 918)	(2 105)

Figure 2

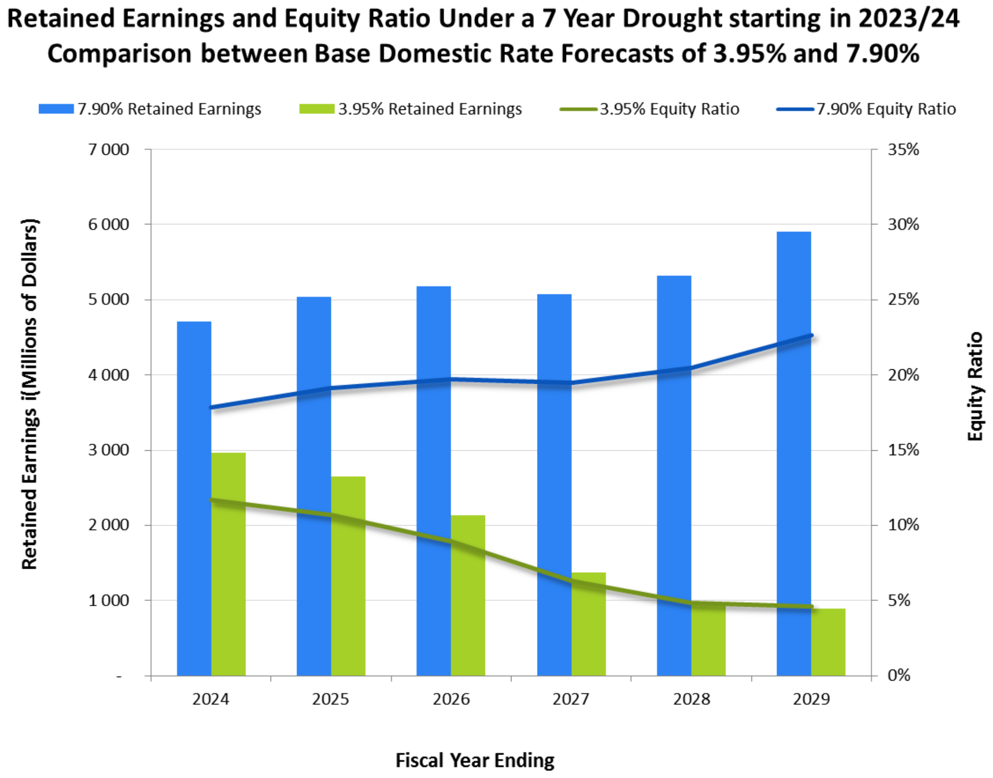
Cumulative Impact to MH16 Update with Interim and 7.90% for 6, 4.54%, 2.00% Retained Earnings

	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Base Scenario: Total Retained Earnings										
MH16 Update with Interim 7.90% for 6, 4.54%, 2.00%	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564	7 214	7 969
Sensitivities: Total Retained Earnings										
5 Year Drought (starting in 2019/20)	2 909	2 849	3 195	3 382	3 581					
7 Year Drought (starting in 2019/20)	3 104	3 362	3 713	3 842	3 611	3 826	4 170			
5 Year Drought (starting in 2022/23)				4 283	4 289	4 616	4 828	5 157		
7 Year Drought (starting in 2022/23)				4 416	4 717	5 044	5 177	5 072	5 322	5 911
Sensitivities: Incremental Increase/(Decrease) in Retained Earnings										
5 Year Drought (starting in 2019/20)	(349)	(758)	(929)	(1 175)	(1 388)					
7 Year Drought (starting in 2019/20)	(154)	(244)	(411)	(716)	(1 358)	(1 672)	(1 817)			
5 Year Drought (starting in 2022/23)				(274)	(680)	(882)	(1 159)	(1 407)		
7 Year Drought (starting in 2022/23)				(142)	(252)	(455)	(810)	(1 492)	(1 892)	(2 059)

A prolonged period of low water flows would have a significant financial impact on Manitoba Hydro as demonstrated in the tables above. For example, regardless of the underlying domestic rate increases, a 7 year drought starting in 2022/23 would reduce the Corporation's retained earnings by approximately $2.1 billion by the end of the 7 year period (2028/29).

Under average water flow conditions, with domestic rate increases of 3.95%, this would result in a retained earnings value of $3.0 billion by 2028/29 as shown in Figure 1. This already represents a reduction from forecast equity of $3.2 billion at the end of 2017/18 notwithstanding 58% cumulative rate increases since April 1, 2017 and the assumption of average water conditions. If the Corporation should instead experience a drought under these conditions and assuming that the Corporation took no compensating rate action, the retained earnings value would deteriorate to $900 million with an equity ratio of 5% by 2028/29. Figure 3 below compares these results to the same 7 year drought under MH16 Update with Interim 7.9% rate increases. Retained earnings after the 7 year drought is almost $6 billion with an equity ratio of 23% by 2028/29 showing that the Corporation is in a much better financial position with the 7.9% rate increases to withstand the impacts of drought without the same risk of requiring emergency rate relief.

Figure 3



In its response to Coalition/MH I-2d, Manitoba Hydro demonstrated that higher up-front rate increases reduces the requirement for emergency rate relief from its customers when facing a prolonged period of low water flows. Domestic rate increases of 3.95% are not sufficient to withstand a period of drought and would require the Corporation to request significantly higher compensating rate action to mitigate the impact of a drought than would otherwise be required with 7.9% rate increases.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
5 Year Drought (starting in 2019/20) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES								
General Consumers								
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542
additional*	0	37	116	181	247	319	392	469
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26
Extraprovincial	460	514	469	281	409	580	596	632
Other	28	30	31	31	33	33	34	34
	1 907	2 008	2 184	2 124	2 305	2 556	2 643	2 703
EXPENSES								
Operating and Administrative	536	518	501	526	525	523	536	547
Finance Expense	608	587	677	753	850	942	1 202	1 259
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(36)	(13)
Depreciation and Amortization	375	396	471	515	555	597	689	714
Water Rentals and Assessments	131	130	120	76	76	100	103	108
Fuel and Power Purchased	132	124	140	382	420	195	179	152
Capital and Other Taxes	119	132	145	154	161	165	174	174
Other Expenses	60	116	109	481	94	92	71	64
Corporate Allocation	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 869	2 655	2 589	2 927	3 014
Net Income before Net Movement in Reg. Deferral	(46)	13	33	(744)	(350)	(33)	(283)	(311)
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)
Non-recurring Gain	20	-	-	-	-	-	-	-
Net Income	41	85	147	(280)	(279)	31	(241)	(359)
Net Income Attributable to:								
Manitoba Hydro before Non-recurring Item	33	93	148	(282)	(284)	22	(251)	(370)
Non-recurring Gain	20	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**148**	**(282)**	**(284)**	**22**	**(251)**	**(370)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11
	41	85	147	(280)	(279)	31	(241)	(359)
* Additional General Consumers Revenue								
Percent Increase		3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase		3.36%	7.44%	11.69%	16.10%	20.68%	25.45%	30.41%
Financial Ratios								
Equity	16%	15%	14%	12%	11%	11%	9%	8%
EBITDA Interest Coverage	1.51	1.54	1.64	1.25	1.27	1.55	1.40	1.36
Capital Coverage	1.53	1.40	1.36	0.54	0.65	1.35	0.94	0.94

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
5 Year Drought (starting in 2019/20) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
ASSETS								
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454
Current and Other Assets	1 773	1 915	2 205	2 552	2 595	1 876	1 625	1 664
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211
Total Assets before Regulatory Deferral	21 272	24 305	27 063	28 506	30 086	30 056	30 046	30 034
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241
	21 733	24 839	27 710	29 618	31 269	31 302	31 335	31 276
LIABILITIES AND EQUITY								
Long-Term Debt	15 725	18 141	21 376	22 789	24 194	24 450	25 862	25 928
Current and Other Liabilities	3 204	3 643	3 047	3 820	4 365	4 153	3 035	3 193
Provisions	70	50	49	48	46	45	43	42
Deferred Revenue	450	465	491	520	542	551	561	571
BPIII Reserve Account	196	347	344	265	185	106	26	(0)
Retained Earnings	2 749	2 842	2 990	2 708	2 424	2 446	2 195	1 825
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(437)	(332)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 662	29 569	31 220	31 253	31 286	31 227
Regulatory Deferral Balance	49	49	49	49	49	49	49	49
	21 733	24 839	27 710	29 618	31 269	31 302	31 335	31 276

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT

5 Year Drought (starting in 2019/20) with 3.95% Rate Increases

(In Millions of Dollars)

For the year ended March 31	ACTUAL							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES								
Cash Receipts from Customers	1 901	2 152	2 170	2 033	2 213	2 464	2 551	2 664
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(1 075)	(1 115)	(915)	(918)	(932)
Interest Paid	(553)	(531)	(635)	(704)	(791)	(892)	(1 148)	(1 227)
Interest Received	17	5	11	22	26	19	5	5
	810	734	703	277	333	675	491	510
FINANCING ACTIVITIES								
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 760	2 790	1 390	1 760	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	62
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)
	1 987	3 051	2 588	2 520	1 804	825	812	357
INVESTING ACTIVITIES								
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(256)	(271)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 253)	(1 067)
Net Increase (Decrease) in Cash	(309)	(145)	10	100	(9)	(329)	50	(200)
Cash at Beginning of Year	943	634	488	498	598	590	261	310
Cash at End of Year	634	488	498	598	590	261	310	111

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
7 Year Drought (starting in 2019/20) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
REVENUES										
General Consumers										
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567
additional*	0	37	116	181	247	319	392	469	552	641
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	0	0
Extraprovincial	460	514	469	306	476	563	560	525	583	583
Other	28	30	31	31	33	33	34	34	35	35
	1 907	2 008	2 184	2 149	2 371	2 539	2 608	2 596	2 722	2 825
EXPENSES										
Operating and Administrative	536	518	501	508	512	523	536	574	559	571
Finance Expense	608	587	677	752	838	918	1 182	1 244	1 283	1 290
Finance Income	(17)	(17)	(21)	(29)	(35)	(32)	(37)	(12)	(14)	(13)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739
Water Rentals and Assessments	131	130	120	88	101	98	93	76	103	122
Fuel and Power Purchased	132	124	140	220	167	197	235	497	190	119
Capital and Other Taxes	119	132	145	154	161	165	174	174	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 699	2 403	2 567	2 952	3 341	3 097	3 081
Net Income before Net Movement in Reg. Deferral	(46)	13	33	(550)	(31)	(28)	(344)	(745)	(375)	(256)
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-
Net Income	41	85	147	(85)	40	35	(301)	(792)	(424)	(304)
Net Income Attributable to:										
Manitoba Hydro before Non-recurring Item	33	93	148	(88)	35	27	(311)	(803)	(427)	(307)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**148**	**(88)**	**35**	**27**	**(311)**	**(803)**	**(427)**	**(307)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2
	41	85	147	(85)	40	35	(301)	(792)	(424)	(304)
* Additional General Consumers Revenue										
Percent Increase		3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase		3.36%	7.44%	11.69%	16.10%	20.68%	25.45%	30.41%	35.56%	40.91%
Financial Ratios										
Equity	16%	15%	14%	13%	13%	12%	10%	8%	6%	5%
EBITDA Interest Coverage	1.51	1.54	1.64	1.44	1.55	1.57	1.35	1.02	1.32	1.42
Capital Coverage	1.53	1.40	1.36	0.91	1.27	1.37	0.83	0.14	0.79	0.97

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
7 Year Drought (starting in 2019/20) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ASSETS										
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414
Current and Other Assets	1 773	1 915	2 205	2 545	2 503	1 791	1 682	1 690	1 578	1 848
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123
Total Assets before Regulatory Deferral	21 272	24 305	27 063	28 499	29 995	29 971	30 103	30 061	29 890	30 112
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143
	21 733	24 839	27 710	29 611	31 177	31 217	31 392	31 302	31 082	31 255
LIABILITIES AND EQUITY										
Long-Term Debt	15 725	18 141	21 376	22 589	23 594	23 850	25 462	25 922	25 833	25 772
Current and Other Liabilities	3 204	3 643	3 047	3 818	4 360	4 151	3 035	3 195	3 480	4 010
Provisions	70	50	49	48	46	45	43	42	41	40
Deferred Revenue	450	465	491	520	542	551	561	571	582	593
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 990	2 902	2 937	2 964	2 653	1 849	1 422	1 115
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(437)	(326)	(325)	(324)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 662	29 562	31 128	31 169	31 343	31 253	31 033	31 206
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 710	29 611	31 177	31 217	31 392	31 302	31 082	31 255

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT

7 Year Drought (starting in 2019/20) with 3.95% Rate Increases

(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 901	2 152	2 170	2 058	2 280	2 447	2 516	2 558	2 709	2 813
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(907)	(875)	(917)	(964)	(1 273)	(976)	(935)
Interest Paid	(553)	(531)	(635)	(704)	(782)	(866)	(1 125)	(1 210)	(1 257)	(1 261)
Interest Received	17	5	11	22	26	18	7	4	8	6
	810	734	703	470	648	682	433	79	484	623
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 560	2 390	1 390	1 960	990	590	1 150
Sinking Fund Withdrawals	146	0	0	120	318	813	182	56	356	167
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)
	1 987	3 051	2 588	2 320	1 404	825	1 012	751	529	597
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(250)	(267)	(282)	(281)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 247)	(1 062)	(1 082)	(1 095)
Net Increase (Decrease) in Cash	(309)	(145)	10	93	(94)	(322)	198	(232)	(68)	124
Cash at Beginning of Year	943	634	488	498	591	498	176	374	141	73
Cash at End of Year	634	488	498	591	498	176	374	141	73	197

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
5 Year Drought (starting in 2022/23) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
General Consumers											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	0	37	116	181	247	319	392	469	552	641	735
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	0	0	0
Extraprovincial	460	514	469	421	568	694	562	525	630	439	483
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 184	2 264	2 464	2 670	2 609	2 596	2 769	2 681	2 837
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	547	559	571	583
Finance Expense	608	587	677	749	829	905	1 163	1 218	1 245	1 253	1 279
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(38)	(11)	(12)	(13)	(14)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	94	85	111	106	111
Fuel and Power Purchased	132	124	140	158	165	156	229	302	154	159	149
Capital and Other Taxes	119	132	145	154	161	165	174	174	175	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 403	2 530	2 927	3 102	3 032	3 069	3 119
Net Income before Net Movement in Reg. Deferral	(46)	13	33	(395)	60	140	(318)	(506)	(263)	(388)	(282)
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	147	70	131	204	(275)	(553)	(312)	(437)	(327)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	148	67	126	195	(285)	(565)	(315)	(439)	(330)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**148**	**67**	**126**	**195**	**(285)**	**(565)**	**(315)**	**(439)**	**(330)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	147	70	131	204	(275)	(553)	(312)	(437)	(327)
* Additional General Consumers Revenue											
Percent Increase		3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase		3.36%	7.44%	11.69%	16.10%	20.68%	25.45%	30.41%	35.56%	40.91%	46.48%
Financial Ratios											
Equity	16%	15%	14%	14%	14%	14%	12%	10%	9%	8%	7%
EBITDA Interest Coverage	1.51	1.54	1.64	1.59	1.64	1.72	1.38	1.21	1.42	1.33	1.42
Capital Coverage	1.53	1.40	1.36	1.21	1.45	1.70	0.88	0.58	0.97	0.75	0.92

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
5 Year Drought (starting in 2022/23) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 205	2 497	2 550	1 806	1 524	1 770	1 770	1 900	1 911
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 063	28 451	30 041	29 987	29 945	30 141	30 082	30 164	30 135
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 710	29 563	31 224	31 233	31 234	31 382	31 273	31 307	31 233
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 868	25 340	25 252	25 191	26 433
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 151	3 036	3 196	3 480	4 003	3 007
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 990	3 057	3 183	3 378	3 093	2 529	2 213	1 774	1 444
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(345)	(344)	(343)	(343)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 662	29 514	31 175	31 184	31 185	31 333	31 224	31 258	31 184
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 710	29 563	31 224	31 233	31 234	31 382	31 273	31 307	31 233

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT

5 Year Drought (starting in 2022/23) with 3.95% Rate Increases

(In Millions of Dollars)

For the year ended March 31	**ACTUAL**										
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 170	2 173	2 372	2 578	2 517	2 558	2 757	2 668	2 824
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(869)	(885)	(894)	(959)	(1 059)	(948)	(959)	(965)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(853)	(1 106)	(1 185)	(1 219)	(1 232)	(1 257)
Interest Received	17	5	11	22	26	19	7	3	6	5	7
	810	734	703	622	743	851	459	317	596	483	609
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 760	990	590	1 150	1 390
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	350	160	260
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 987	3 051	2 588	2 120	1 404	625	812	747	523	590	467
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(261)	(275)	(274)	(283)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 243)	(1 056)	(1 075)	(1 088)	(1 121)
Net Increase (Decrease) in Cash	(309)	(145)	10	45	1	(353)	28	8	44	(15)	(44)
Cash at Beginning of Year	943	634	488	498	544	544	191	220	227	271	256
Cash at End of Year	634	488	498	544	544	191	220	227	271	256	212

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
7 Year Drought (starting in 2022/23) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**												
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
REVENUES													
General Consumers													
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583	1 599	1 614
additional*	0	37	116	181	247	319	392	469	552	641	735	835	940
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	0	0	0	0	0
Extraprovincial	460	514	469	421	568	694	633	671	619	390	293	351	580
Other	28	30	31	31	33	33	34	34	35	35	36	36	37
	1 907	2 008	2 184	2 264	2 464	2 670	2 680	2 742	2 758	2 633	2 647	2 822	3 171
EXPENSES													
Operating and Administrative	536	518	501	511	513	524	536	547	559	571	596	595	607
Finance Expense	608	587	677	749	829	905	1 159	1 210	1 222	1 233	1 266	1 303	1 312
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(13)	(13)	(14)	(13)	(14)	(15)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752	765	776
Water Rentals and Assessments	131	130	120	110	113	117	109	114	109	97	80	103	122
Fuel and Power Purchased	132	124	140	158	165	156	155	132	163	217	422	172	126
Capital and Other Taxes	119	132	145	154	161	165	174	174	175	175	175	176	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76	79	84
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 403	2 530	2 864	2 951	3 016	3 096	3 361	3 187	3 197
Net Income before Net Movement in Reg. Deferral	(46)	13	33	(395)	60	140	(184)	(209)	(258)	(464)	(715)	(365)	(26)
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)	(44)	(40)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	147	70	131	204	(141)	(256)	(307)	(512)	(760)	(409)	(66)
Net Income Attributable to:													
Manitoba Hydro before Non-recurring Item	33	93	148	67	126	195	(151)	(268)	(310)	(514)	(763)	(413)	(71)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**148**	**67**	**126**	**195**	**(151)**	**(268)**	**(310)**	**(514)**	**(763)**	**(413)**	**(71)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3	4	5
	41	85	147	70	131	204	(141)	(256)	(307)	(512)	(760)	(409)	(66)
* Additional General Consumers Revenue													
Percent Increase		3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase		3.36%	7.44%	11.69%	16.10%	20.68%	25.45%	30.41%	35.56%	40.91%	46.48%	52.26%	58.28%
Financial Ratios													
Equity	16%	15%	14%	14%	14%	14%	12%	12%	11%	9%	6%	5%	5%
EBITDA Interest Coverage	1.51	1.54	1.64	1.59	1.64	1.72	1.49	1.46	1.43	1.28	1.08	1.36	1.62
Capital Coverage	1.53	1.40	1.36	1.21	1.45	1.70	1.14	1.12	0.98	0.65	0.27	0.82	1.28

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
7 Year Drought (starting in 2022/23) with 3.95% Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS													
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945	33 553	34 299
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)	(6 906)	(7 603)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732	26 647	26 696
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411	493	454
Current and Other Assets	1 773	1 915	2 205	2 497	2 550	1 806	1 658	1 597	1 606	1 867	1 848	2 216	2 195
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081	1 040	1 001
Total Assets before Regulatory Deferral	21 272	24 305	27 063	28 451	30 041	29 987	30 079	29 968	29 917	30 132	30 072	30 395	30 346
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098	1 055	1 014
	21 733	24 839	27 710	29 563	31 224	31 233	31 368	31 209	31 109	31 275	31 170	31 450	31 361
LIABILITIES AND EQUITY													
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 868	24 740	24 652	24 791	26 433	27 166	24 788
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 151	3 036	3 192	3 480	4 011	3 017	2 967	5 318
Provisions	70	50	49	48	46	45	43	42	41	40	39	38	37
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603	615	624
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 990	3 057	3 183	3 378	3 227	2 959	2 649	2 134	1 372	959	888
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(345)	(344)	(343)	(343)	(343)	(343)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 662	29 514	31 175	31 184	31 319	31 160	31 060	31 226	31 121	31 401	31 312
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 710	29 563	31 224	31 233	31 368	31 209	31 109	31 275	31 170	31 450	31 361

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT

7 Year Drought (starting in 2022/23) with 3.95% Rate Increases

(In Millions of Dollars)

For the year ended March 31	**ACTUAL**												
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OPERATING ACTIVITIES													
Cash Receipts from Customers	1 901	2 152	2 170	2 173	2 372	2 578	2 588	2 704	2 746	2 620	2 634	2 809	3 157
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(869)	(885)	(894)	(900)	(918)	(955)	(1 008)	(1 221)	(993)	(978)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(853)	(1 102)	(1 180)	(1 193)	(1 204)	(1 241)	(1 281)	(1 310)
Interest Received	17	5	11	22	26	19	6	5	6	6	7	13	24
	810	734	703	622	743	851	593	610	605	415	179	547	893
FINANCING ACTIVITIES													
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 760	390	590	1 350	1 790	790	(10)
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	350	156	255	150	60
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)	(150)	(60)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)	(5)	(5)
	1 987	3 051	2 588	2 120	1 404	625	812	147	523	786	862	785	(15)
INVESTING ACTIVITIES													
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)	(767)	(798)
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(261)	(271)	(269)	(279)	(286)	(298)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)	(80)	(74)
	(3 106)	(3 931)	(3 281)	(2 697)	(2 146)	(1 830)	(1 243)	(1 056)	(1 070)	(1 083)	(1 117)	(1 133)	(1 170)
Net Increase (Decrease) in Cash	(309)	(145)	10	45	1	(353)	162	(299)	57	118	(76)	199	(292)
Cash at Beginning of Year	943	634	488	498	544	544	191	353	54	111	229	153	352
Cash at End of Year	634	488	498	544	544	191	353	54	111	229	153	352	60

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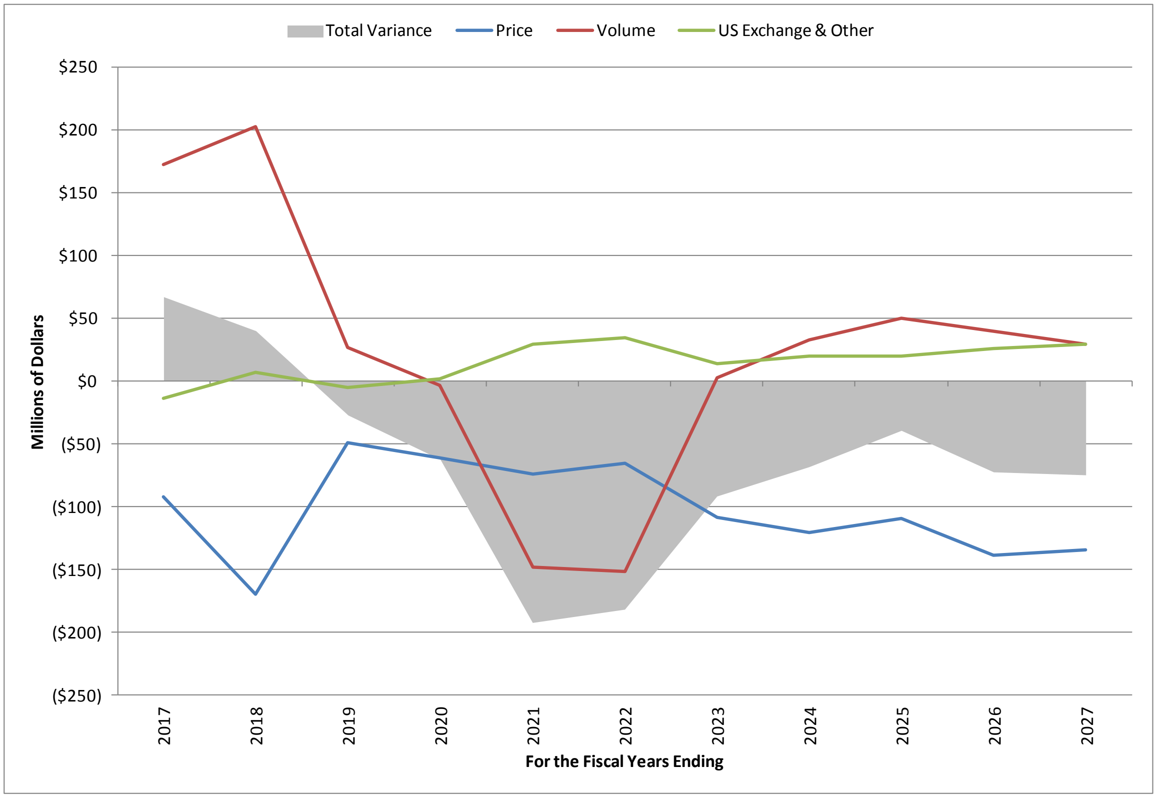
Lower Extraprovincial Revenues

The following **Figure 3.6** shows that MH16 net extraprovincial revenues are $0.7 billion lower compared to MH15 over the 10-year forecast period from 2016/17 to 2026/27 reflected in the grey shaded area ($0.8 billion from 2017/18 to 2026/27).

Figure 3.6 – Change in Net Export Revenues in MH16 compared to MH15



The reduction in export prices accounts for about $1.1 billion of the cumulative reduction of net extraprovincial revenues over the 10-year forecast period to 2026/27. MH16 reflects electricity export prices that are lower by approximately 20% relative to the comparable 2015 forecast. The decline to long-term power prices is due primarily to a reduction to long-term natural gas prices and increased renewable development (primarily wind generation) in the MISO market, aided by substantial subsidies. In addition, the premium that has historically been applied to the long-term dependable forecast prices has been removed as the achievability of this premium has reduced significantly in the MISO market. Reflecting the continuing trend of low capacity value, a January 2017 update removed capacity value from the pricing of potential future uncommitted export sales from surplus dependable energy.

Figure 3.6 – Change in Net Export Revenues in MH16 Update compared to MH15

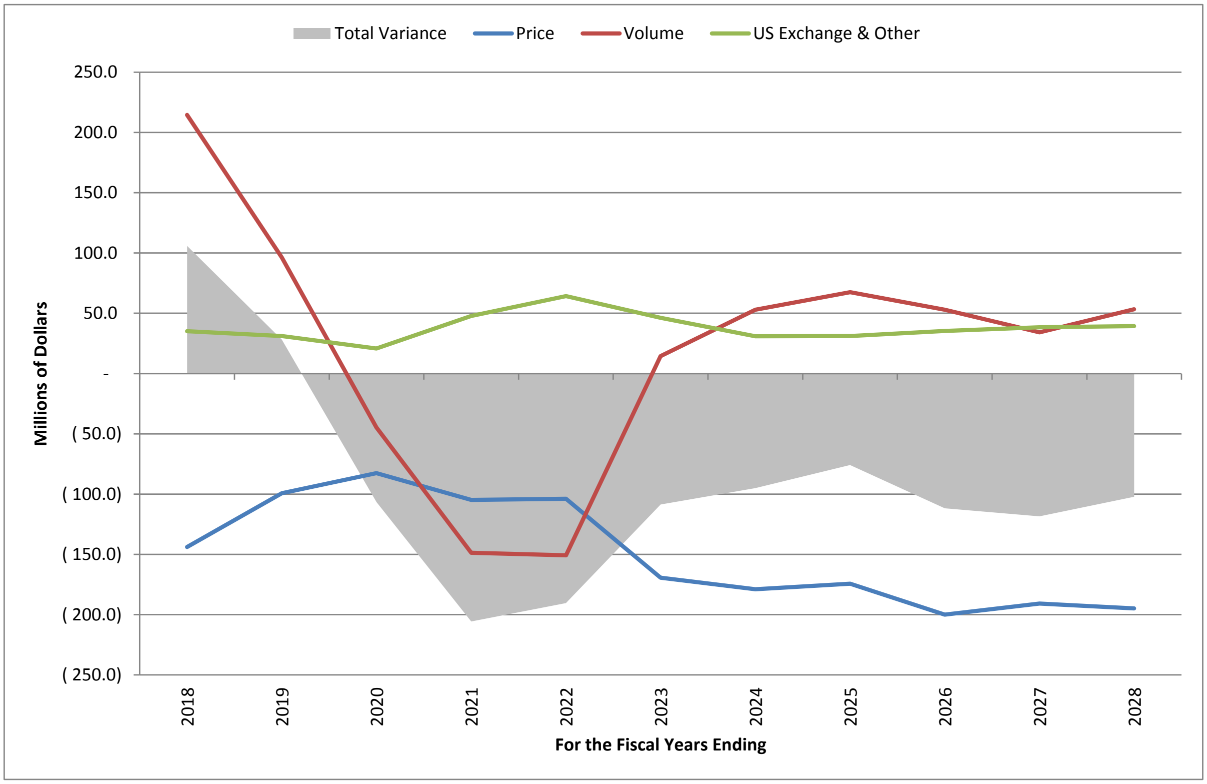
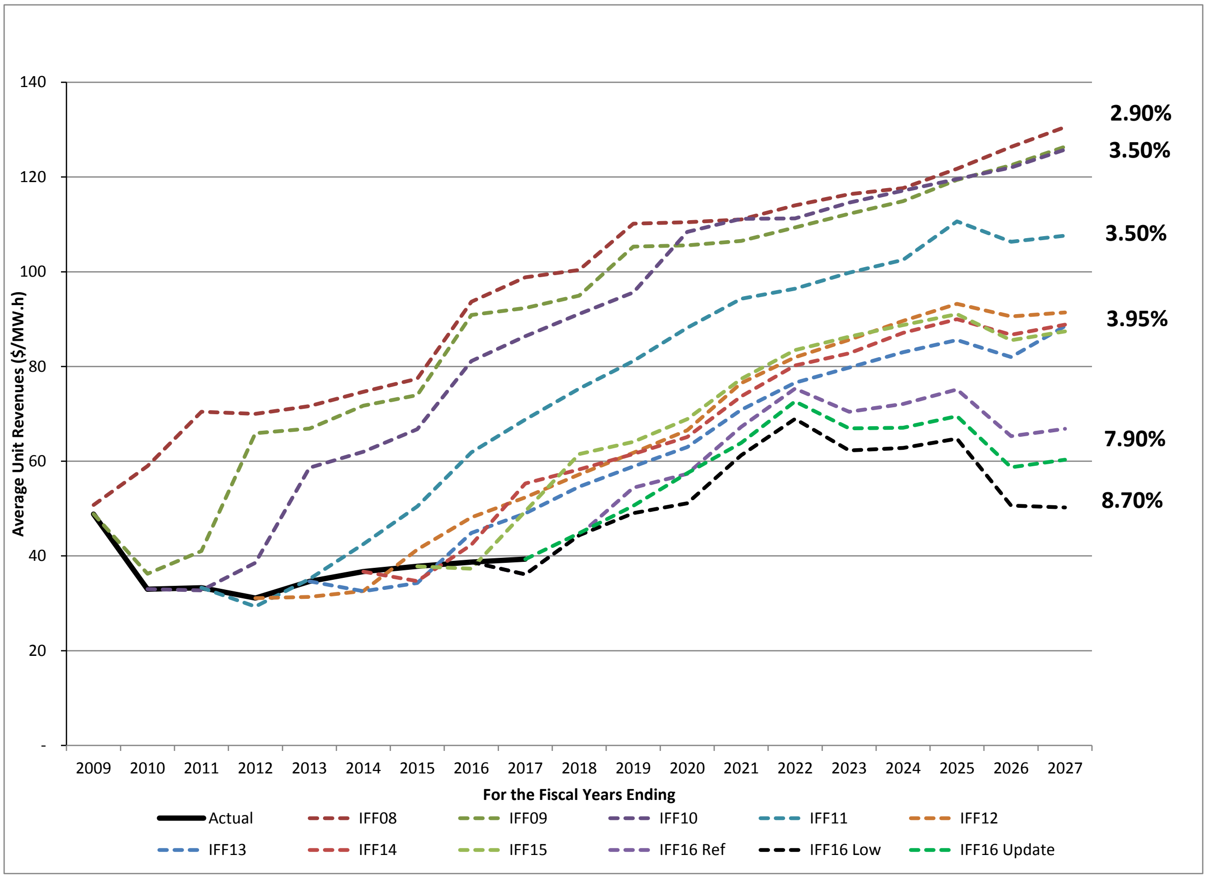


Figure 3.7 Progression of Forecast Average Unit Revenues Compared to Actual Average Prices



REFERENCE:

PUB MFR 80

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the impact of a change in mix of exports (e.g. firm vs. opportunity) between forecasts is captured in PUB MFR 80 under the Volume row?

b) Please revise the response to PUB MFR 80 to include the IFF16-Update.

RATIONALE FOR QUESTION:

To understand the basis for the variance analysis and to obtain the variance analysis for the most recent average Extraprovincial Revenue forecast.

RESPONSE:

a) Confirmed. The impact of a change in mix of exports (e.g. firm vs. opportunity) between forecasts is one of the impacts captured in PUB MFR 80 under the Volume row.

b) Please see the updated Figure 1 below.

Figure 1. Price/Volume Components for Unit Revenues for Total Export Sales
(Nominal canadian Dollars / MWh)

NFAT TO IFF13

Total Export Sales	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
NFAT ($/MW.h)	46.7	49.8	53.0	55.5	59.2	72.0	77.9	80.5	82.4	84.8	80.8	83.5	84.8	87.2	89.3	91.4	93.6
IFF 13 ($/MW.h)	44.9	49.0	54.6	58.9	63.0	70.9	76.6	79.8	83.0	85.6	82.0	88.5	90.6	92.6	95.3	97.3	100.3
%Change Total	**-3.9%**	**-1.6%**	**3.1%**	**6.1%**	**6.4%**	**-1.6%**	**-1.7%**	**-0.9%**	**0.8%**	**0.9%**	**1.4%**	**6.0%**	**6.8%**	**6.2%**	**6.7%**	**6.4%**	**7.2%**
Total Change ($/MW.h)	**-1.8**	**-0.8**	**1.6**	**3.4**	**3.8**	**-1.1**	**-1.3**	**-0.7**	**0.6**	**0.8**	**1.2**	**5.0**	**5.8**	**5.4**	**6.0**	**5.9**	**6.7**
Change due to Price ($/MW.h)	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	0.0
Change due to Volume ($/MW.h)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Change due to Other ($/MW.h)	-1.8	-0.8	1.6	3.4	3.8	-1.1	-1.3	-0.7	0.6	0.8	1.2	5.0	5.8	5.4	6.0	5.9	6.7

IFF13 TO IFF14

Total Export Sales	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
IFF 13 ($/MW.h)	49.0	54.6	58.9	63.0	70.9	76.6	79.8	83.0	85.6	82.0	88.5	90.6	92.6	95.3	97.3	100.3	103.2
IFF 14 ($/MW.h)	55.3	58.3	61.5	65.1	73.7	80.2	82.8	87.1	90.0	86.7	88.8	90.2	91.8	94.9	96.1	98.7	101.1
%Change Total	**12.9%**	**6.7%**	**4.4%**	**3.3%**	**4.0%**	**4.7%**	**3.8%**	**4.9%**	**5.1%**	**5.8%**	**0.4%**	**-0.4%**	**-0.9%**	**-0.4%**	**-1.2%**	**-1.7%**	**-2.0%**
Total Change ($/MW.h)	**6.3**	**3.6**	**2.6**	**2.1**	**2.8**	**3.6**	**3.0**	**4.1**	**4.4**	**4.7**	**0.3**	**-0.4**	**-0.8**	**-0.4**	**-1.2**	**-1.7**	**-2.1**
Change due to Price ($/MW.h)	8.2	5.1	4.3	4.2	2.8	3.5	2.6	3.2	3.5	1.4	0.9	0.8	0.2	0.5	0.3	0.1	0.0
Change due to Volume ($/MW.h)	-2.6	-2.1	-2.5	-2.9	-1.8	-1.6	-1.2	-0.8	-0.8	1.5	-1.5	-1.0	-0.5	-0.4	-0.3	-0.4	-0.6
Change due to Other ($/MW.h)	0.7	0.6	0.8	0.9	1.8	1.7	1.6	1.7	1.8	1.8	0.9	-0.2	-0.5	-0.6	-1.2	-1.4	-1.5

IFF14 TO IFF15

Total Export Sales	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
IFF 14 ($/MW.h)	58.3	61.5	65.1	73.7	80.2	82.8	87.1	90.0	86.7	88.8	90.2	91.8	94.9	96.1	98.7	101.1	104.4
IFF 15 ($/MW.h)	61.5	64.1	68.9	77.4	83.4	86.3	88.7	91.0	85.5	87.4	88.5	91.3	94.2	95.3	98.0	100.6	103.0
%Change Total	**5.6%**	**4.2%**	**5.8%**	**5.0%**	**4.0%**	**4.2%**	**1.8%**	**1.2%**	**-1.4%**	**-1.6%**	**-1.9%**	**-0.6%**	**-0.8%**	**-0.9%**	**-0.7%**	**-0.5%**	**-1.3%**
Total Change ($/MW.h)	**3.3**	**2.6**	**3.8**	**3.7**	**3.2**	**3.5**	**1.6**	**1.1**	**-1.2**	**-1.4**	**-1.7**	**-0.6**	**-0.7**	**-0.8**	**-0.7**	**-0.5**	**-1.4**
Change due to Price ($/MW.h)	0.3	0.0	1.1	1.9	1.2	1.7	-0.2	-0.7	-2.4	-2.6	-3.5	-2.4	-2.6	-2.7	-2.0	-1.4	-1.5
Change due to Volume ($/MW.h)	3.2	2.7	2.5	1.9	2.2	2.0	1.9	1.9	1.5	1.4	2.0	2.1	2.1	2.2	1.9	1.5	0.9
Change due to Other ($/MW.h)	-0.2	-0.1	0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.3	-0.2	-0.3	-0.3	-0.3	-0.4	-0.5	-0.6	-0.8

IFF15 TO IFF16

Total Export Sales	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
IFF 15 ($/MW.h)	64.1	68.9	77.4	83.4	86.3	88.7	91.0	85.5	87.4	88.5	91.3	94.2	95.3	98.0	100.6	103.0	105.5
IFF 16 ($/MW.h)	54.4	57.3	67.3	75.3	70.5	72.1	75.2	65.3	66.9	67.3	69.4	72.4	74.8	78.0	81.4	85.0	88.6
%Change Total	**-15.1%**	**-16.8%**	**-13.1%**	**-9.7%**	**-18.3%**	**-18.8%**	**-17.4%**	**-23.7%**	**-23.5%**	**-24.0%**	**-23.9%**	**-23.1%**	**-21.4%**	**-20.4%**	**-19.1%**	**-17.5%**	**-16.1%**
Total Change ($/MW.h)	**-9.7**	**-11.6**	**-10.1**	**-8.1**	**-15.8**	**-16.7**	**-15.9**	**-20.2**	**-20.6**	**-21.2**	**-21.8**	**-21.8**	**-20.4**	**-20.0**	**-19.2**	**-18.0**	**-16.9**
Change due to Price ($/MW.h)	-7.0	-10.1	-13.4	-13.5	-14.7	-14.8	-13.3	-17.0	-17.3	-18.0	-18.7	-18.9	-18.1	-18.3	-18.2	-17.9	-18.1
Change due to Volume ($/MW.h)	-1.3	-1.1	2.8	4.3	-2.8	-3.7	-4.4	-6.0	-6.0	-6.2	-6.2	-6.1	-5.8	-5.4	-5.0	-4.5	-3.3
Change due to Other ($/MW.h)	-1.4	-0.4	0.5	1.1	1.7	1.8	1.9	2.7	2.7	2.9	3.1	3.2	3.5	3.7	4.1	4.4	4.5

IFF16 TO MH16-Update

Total Export Sales	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
IFF 16 ($/MW.h)	57.3	67.3	75.3	70.5	72.1	75.2	65.3	66.9	67.3	69.4	72.4	74.8	78.0	81.4	85.0	88.6	86.3
IFF 16_Update ($/MW.h)	57.1	65.3	73.6	67.5	67.4	69.8	60.3	62.0	62.9	65.7	69.2	71.6	75.3	78.1	80.8	83.8	79.0
%Change Total	**-0.3%**	**-2.9%**	**-2.3%**	**-4.3%**	**-6.5%**	**-7.2%**	**-7.7%**	**-7.2%**	**-6.5%**	**-5.3%**	**-4.4%**	**-4.4%**	**-3.5%**	**-4.0%**	**-4.9%**	**-5.4%**	**-8.5%**
Total Change ($/MW.h)	**-0.2**	**-1.9**	**-1.8**	**-3.0**	**-4.7**	**-5.4**	**-5.0**	**-4.8**	**-4.4**	**-3.7**	**-3.2**	**-3.3**	**-2.7**	**-3.3**	**-4.2**	**-4.8**	**-7.3**
Change due to Price ($/MW.h)	-1.0	-0.9	-0.4	-2.3	-4.8	-5.3	-3.9	-3.8	-2.9	-2.0	-1.2	-1.0	-0.5	-1.0	-1.6	-1.8	-2.6
Change due to Volume ($/MW.h)	-1.4	-1.9	-1.6	-1.5	-1.5	-2.3	-2.4	-2.3	-2.6	-2.6	-2.8	-3.1	-3.1	-3.3	-3.9	-4.3	-5.4
Change due to Other ($/MW.h)	2.3	0.9	0.3	0.9	1.6	2.3	1.3	1.3	1.0	0.9	0.7	0.8	0.8	1.0	1.3	1.4	0.7

PUB MFR 80
Export & Domestic Revenue

Update of year-over-year comparisons of price and volume components for unit revenues for total export sales, beginning with the NFAT forecast (i.e. NFAT, IFF13, IFF14, IFF15, current IFF). [NFAT Exhibit MMF-31 p.10]

Figure 1 provides the unit revenues for total export sales for NFAT, IFF13, IFF14, IFF15, and IFF16. The change in the unit revenues between respective IFFs is given in terms of an absolute ($/MWh) and percentage change.

The total change in the unit revenues for total export sales is broken into the price, volume and other components. The price and volume components consist of the effect of price and volume changes, respectively, for all export sales and flow-related revenues and costs. The change related to 'other' reflects the factors that are not clearly defined by price and volume (for example, the transmission costs and revenues and MISO membership costs, amongst others).

Price and volume are not independent factors. A change in price will change to some extent the energy volumes. In the attached table, the change due to price for the transition from IFF13 to IFF14, as an example, is calculated as the total effect of only changing the prices. The change due to volume represents the remaining difference between the two IFF forecasts. Volume changes include Manitoba load, export contracts and deferral of in-service dates for generating stations, amongst others.

Figure 1. Price/Volume Components for Unit Revenues for Total Export Sales

(Nominal Canadian Dollars / MWh)

NFAT TO IFF13

Total Export Sales	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
NFAT ($/MW.h)	46.7	49.8	53.0	55.5	59.2	72.0	77.9	80.5	82.4	84.8	80.8	83.5	84.8	87.2	89.3	91.4	93.6
IFF 13 ($/MW.h)	44.9	49.0	54.6	58.9	63.0	70.9	76.6	79.8	83.0	85.6	82.0	88.5	90.6	92.6	95.3	97.3	100.3
%Change Total	**-3.9%**	**-1.6%**	**3.1%**	**6.1%**	**6.4%**	**-1.6%**	**-1.7%**	**-0.9%**	**0.8%**	**0.9%**	**1.4%**	**6.0%**	**6.8%**	**6.2%**	**6.7%**	**6.4%**	**7.2%**
Total Change ($/MW.h)	**-1.8**	**-0.8**	**1.6**	**3.4**	**3.8**	**-1.1**	**-1.3**	**-0.7**	**0.6**	**0.8**	**1.2**	**5.0**	**5.8**	**5.4**	**6.0**	**5.9**	**6.7**
Change due to Price ($/MW.h)	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	0.0
Change due to Volume ($/MW.h)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Change due to Other ($/MW.h)	-1.8	-0.8	1.6	3.4	3.8	-1.1	-1.3	-0.7	0.6	0.8	1.2	5.0	5.8	5.4	6.0	5.9	6.7

IFF13 TO IFF14

Total Export Sales	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
IFF 13 ($/MW.h)	49.0	54.6	58.9	63.0	70.9	76.6	79.8	83.0	85.6	82.0	88.5	90.6	92.6	95.3	97.3	100.3	103.2
IFF 14 ($/MW.h)	55.3	58.3	61.5	65.1	73.7	80.2	82.8	87.1	90.0	86.7	88.8	90.2	91.8	94.9	96.1	98.7	101.1
%Change Total	**12.9%**	**6.7%**	**4.4%**	**3.3%**	**4.0%**	**4.7%**	**3.8%**	**4.9%**	**5.1%**	**5.8%**	**0.4%**	**-0.4%**	**-0.9%**	**-0.4%**	**-1.2%**	**-1.7%**	**-2.0%**
Total Change ($/MW.h)	**6.3**	**3.6**	**2.6**	**2.1**	**2.8**	**3.6**	**3.0**	**4.1**	**4.4**	**4.7**	**0.3**	**-0.4**	**-0.8**	**-0.4**	**-1.2**	**-1.7**	**-2.1**
Change due to Price ($/MW.h)	8.2	5.1	4.3	4.2	2.8	3.5	2.6	3.2	3.5	1.4	0.9	0.8	0.2	0.5	0.3	0.1	0.0
Change due to Volume ($/MW.h)	-2.6	-2.1	-2.5	-2.9	-1.8	-1.6	-1.2	-0.8	-0.8	1.5	-1.5	-1.0	-0.5	-0.4	-0.3	-0.4	-0.6
Change due to Other ($/MW.h)	0.7	0.6	0.8	0.9	1.8	1.7	1.6	1.7	1.8	1.8	0.9	-0.2	-0.5	-0.6	-1.2	-1.4	-1.5

IFF14 TO IFF15

Total Export Sales	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
IFF 14 ($/MW.h)	58.3	61.5	65.1	73.7	80.2	82.8	87.1	90.0	86.7	88.8	90.2	91.8	94.9	96.1	98.7	101.1	104.4
IFF 15 ($/MW.h)	61.5	64.1	68.9	77.4	83.4	86.3	88.7	91.0	85.5	87.4	88.5	91.3	94.2	95.3	98.0	100.6	103.0
%Change Total	**5.6%**	**4.2%**	**5.8%**	**5.0%**	**4.0%**	**4.2%**	**1.8%**	**1.2%**	**-1.4%**	**-1.6%**	**-1.9%**	**-0.6%**	**-0.8%**	**-0.9%**	**-0.7%**	**-0.5%**	**-1.3%**
Total Change ($/MW.h)	**3.3**	**2.6**	**3.8**	**3.7**	**3.2**	**3.5**	**1.6**	**1.1**	**-1.2**	**-1.4**	**-1.7**	**-0.6**	**-0.7**	**-0.8**	**-0.7**	**-0.5**	**-1.4**
Change due to Price ($/MW.h)	0.3	0.0	1.1	1.9	1.2	1.7	-0.2	-0.7	-2.4	-2.6	-3.5	-2.4	-2.6	-2.7	-2.0	-1.4	-1.5
Change due to Volume ($/MW.h)	3.2	2.7	2.5	1.9	2.2	2.0	1.9	1.9	1.5	1.4	2.0	2.1	2.1	2.2	1.9	1.5	0.9
Change due to Other ($/MW.h)	-0.2	-0.1	0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.3	-0.2	-0.3	-0.3	-0.3	-0.4	-0.5	-0.6	-0.8

IFF15 TO IFF16

Total Export Sales	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
IFF 15 ($/MW.h)	64.1	68.9	77.4	83.4	86.3	88.7	91.0	85.5	87.4	88.5	91.3	94.2	95.3	98.0	100.6	103.0	105.5
IFF 16 ($/MW.h)	54.4	57.3	67.3	75.3	70.5	72.1	75.2	65.3	66.9	67.3	69.4	72.4	74.8	78.0	81.4	85.0	88.6
%Change Total	**-15%**	**-17%**	**-13%**	**-10%**	**-18%**	**-19%**	**-17%**	**-24%**	**-24%**	**-24%**	**-24%**	**-23%**	**-21%**	**-20%**	**-19%**	**-18%**	**-16%**
Total Change ($/MW.h)	**-9.7**	**-11.6**	**-10.1**	**-8.1**	**-15.8**	**-16.7**	**-15.9**	**-20.2**	**-20.6**	**-21.2**	**-21.8**	**-21.8**	**-20.4**	**-20.0**	**-19.2**	**-18.0**	**-16.9**
Change due to Price ($/MW.h)	-7.0	-10.1	-13.4	-13.5	-14.7	-14.8	-13.3	-17.0	-17.3	-18.0	-18.7	-18.9	-18.1	-18.3	-18.2	-17.9	-18.1
Change due to Volume ($/MW.h)	-1.3	-1.1	2.8	4.3	-2.8	-3.7	-4.4	-6.0	-6.0	-6.2	-6.2	-6.1	-5.8	-5.4	-5.0	-4.5	-3.3
Change due to Other ($/MW.h)	-1.4	-0.4	0.5	1.1	1.7	1.8	1.9	2.7	2.7	2.9	3.1	3.2	3.5	3.7	4.1	4.4	4.5

SUPPLEMENTAL FILING TO MANITOBA HYDRO'S 2015/16 & 2016/17 GENERAL RATE APPLICATION

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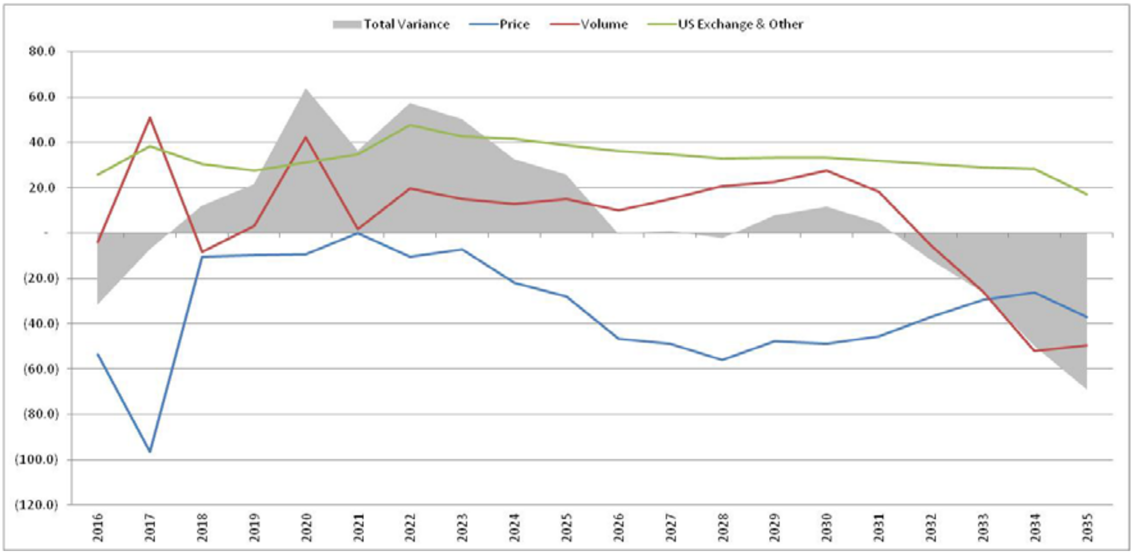
2.3 Rates Have Not Increased to Fully Compensate for Reductions in Net Extraprovincial Revenue

The following Figure provides the total change in net extraprovincial revenues (grey area) between MH 14 and MH15 which consists of the changes related to export electricity prices (blue), export and import deliveries (red), and U.S. exchange (green).

Figure 8. Net Extraprovincial Revenues - Comparison MH15 vs. MH14



In 2015/16, overall average export electricity prices are approximately 20% lower compared to MH14 due mainly to lower opportunity prices resulting from lower natural gas prices. This decrease is also impacted by less higher-priced dependable sales and more lower-priced off-peak opportunity sales.

In 2016/17, overall average export electricity prices in MH15 are forecast to be approximately 34% lower than in MH14 due mainly to significantly lower opportunity prices resulting from lower natural gas prices. This decrease is partially offset by higher projected net generation and dependable sales compared to MH14 due to higher forecast inflows under median flows assumed in MH15 compared to the average of 102 historical flow years assumed in MH14.

In the period 2017/18 to 2024/25, overall average export electricity prices are forecast in MH15 to be approximately 3% lower compared to MH14 mainly due to lower opportunity prices, partially offset by more dependable sales relative to opportunity sales resulting from increased DSM savings compared to MH14. From 2025/26 to end of the

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

PREAMBLE TO IR (IF ANY):

QUESTION:

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

RATIONALE FOR QUESTION:

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

RESPONSE:

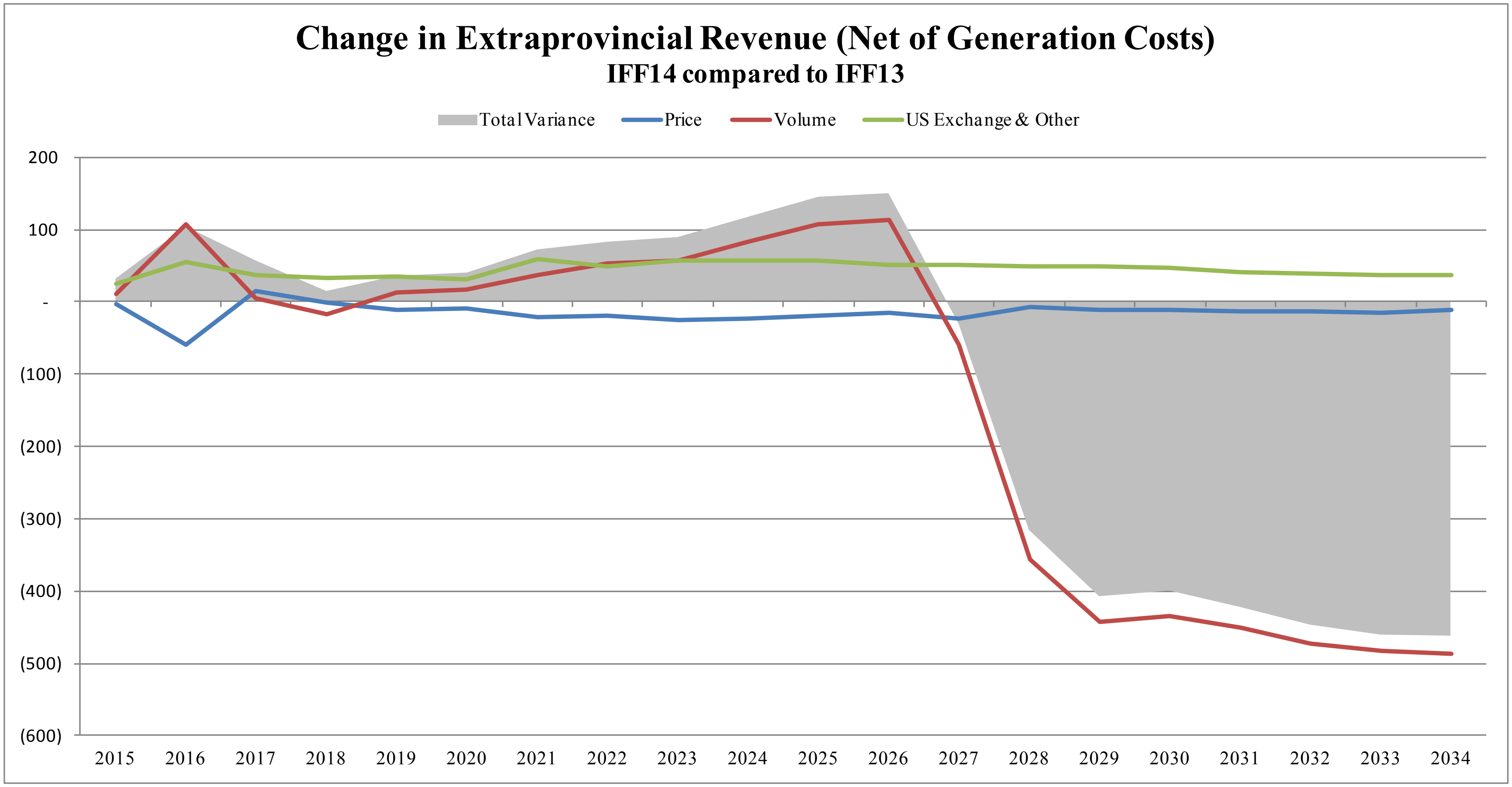
The following figure and schedule provide the change in net extraprovincial revenues (net of water rentals and fuel and power purchases) from IFF13 to IFF14 due to changes in price, volume and US exchange and other.

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

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

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

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

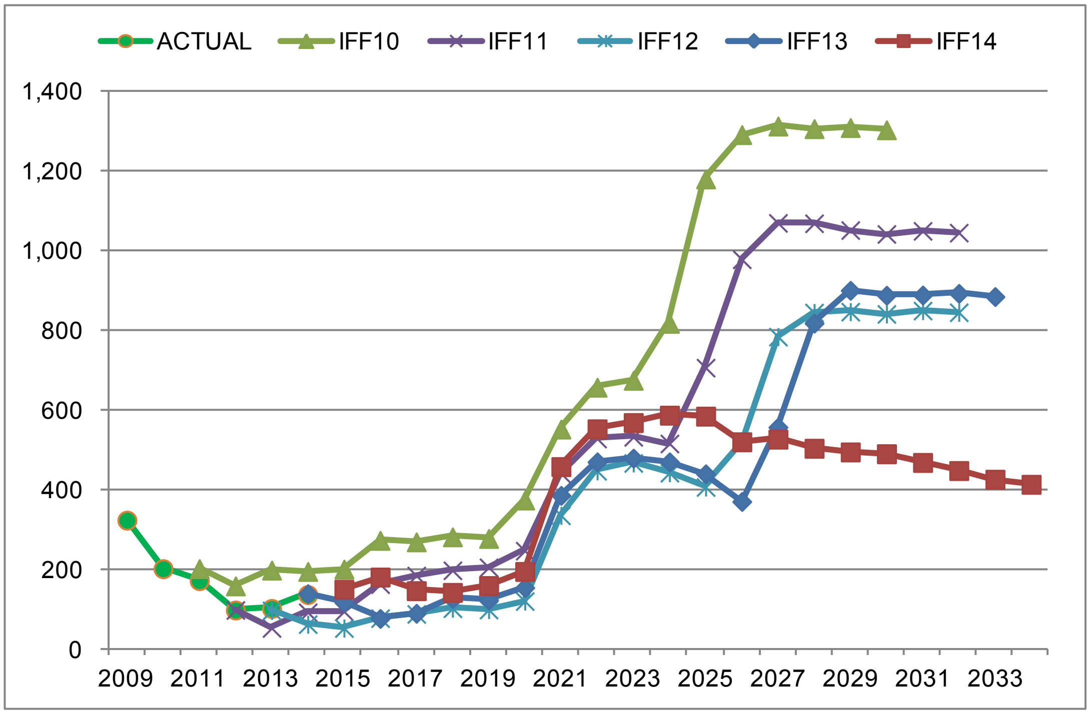


Change in Extraprovincial Revenue (Net of Generation Costs)

IFF14 compared to IFF13

Figure 5-1: Extra-provincial Revenues

(Net of Water Rentals and Fuel and Power Purchases)



In comparison to the 2013 Electric Export Price Forecast, the 2014 forecast projects prices for a long term dependable electricity product will be, on average, 7% lower over the period 2016/17 to 2035/36. Over that time horizon energy prices (both on and off peak) are forecast to be an average of 3% lower with the value of capacity down 15% relative to the 2013 outlook. The decrease reflects the forecast for lower natural gas prices, with a minor offset due to the stabilizing effects of relatively flat year over year coal and carbon price forecasts, along with some additional clarity on US environmental regulation and resulting coal fleet retirements.

Relative to the assumptions in MH16, long-term export prices continue to see further flattened growth, with natural gas price declines along with the increased buildout of renewables putting downward pressure on price appreciation. On-peak prices are down approximately 7% compared to the forecast underpinning MH16 and down approximately 17% from the 2016 EEPF. Off-peak prices have seen a larger decline than on-peak prices, down 10% compared to the forecast underpinning MH16 and down 20% from the 2016 EEPF, showing the larger effect that wind generation has in pushing the prices down overnight. The 2016 EEPF was itself an approximately 15% decline in export prices in comparison to those assumed in MH15.

Average unit revenues and costs have been revised in PUB MFR 24 and the 2017 third-party and consensus forecast prices have been provided in revised PUB MFR 79.

2.5 Water Conditions

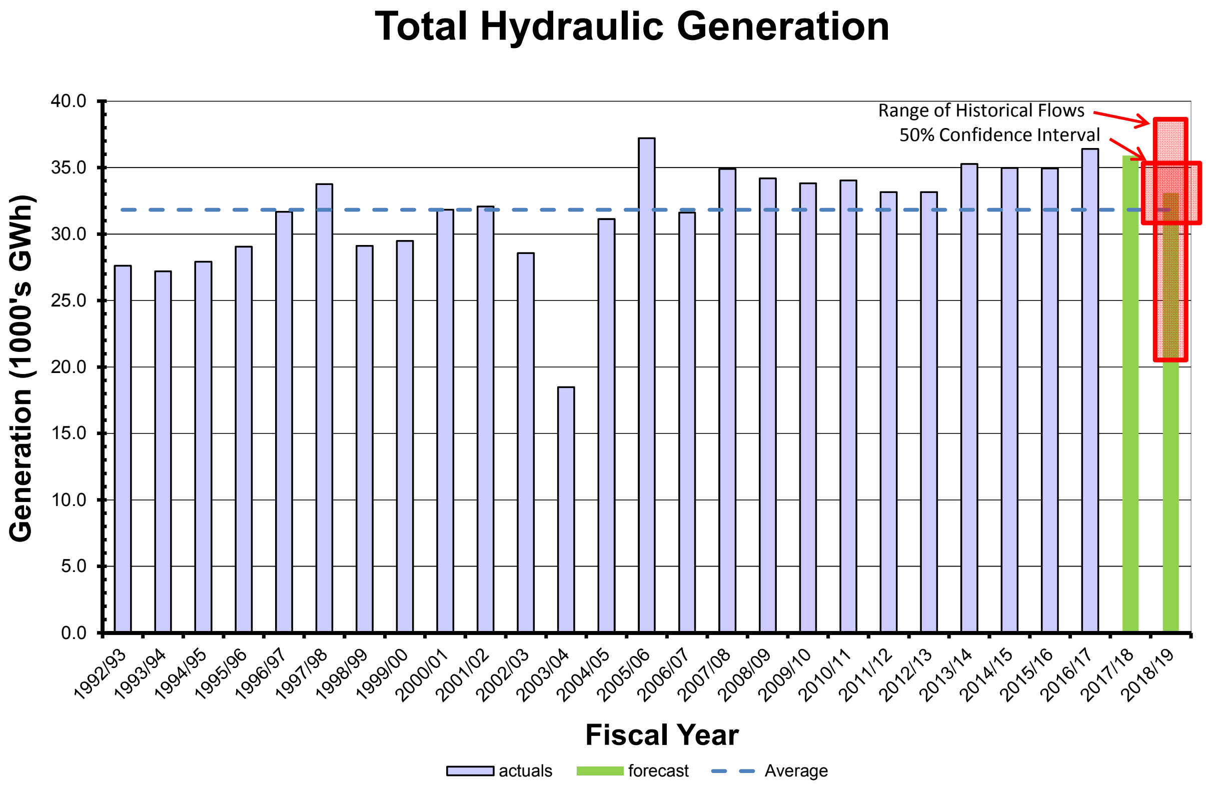
Precipitation

System precipitation since March 1, 2017 has been normal to above normal for all basins with the exception of the Winnipeg River Basin being below normal. Runoff volumes in the Churchill and Saskatchewan River basins were well above average to record highs due to significant accumulated winter snowpack. The precipitation report for the past 60 days has been below average for all basins.

Inflows

Figure 4 (which is an update to Figure 7.13 from Tab 7) below shows historical daily inflows beginning in 1977, with inflows for 2016 and 2017 and the average shown as highlighted. Despite the below average precipitation in the past two months, hydraulic energy from inflow is still above average as the significant runoff volumes in the north slowly recede.

Figure 6. Total Hydraulic Generation

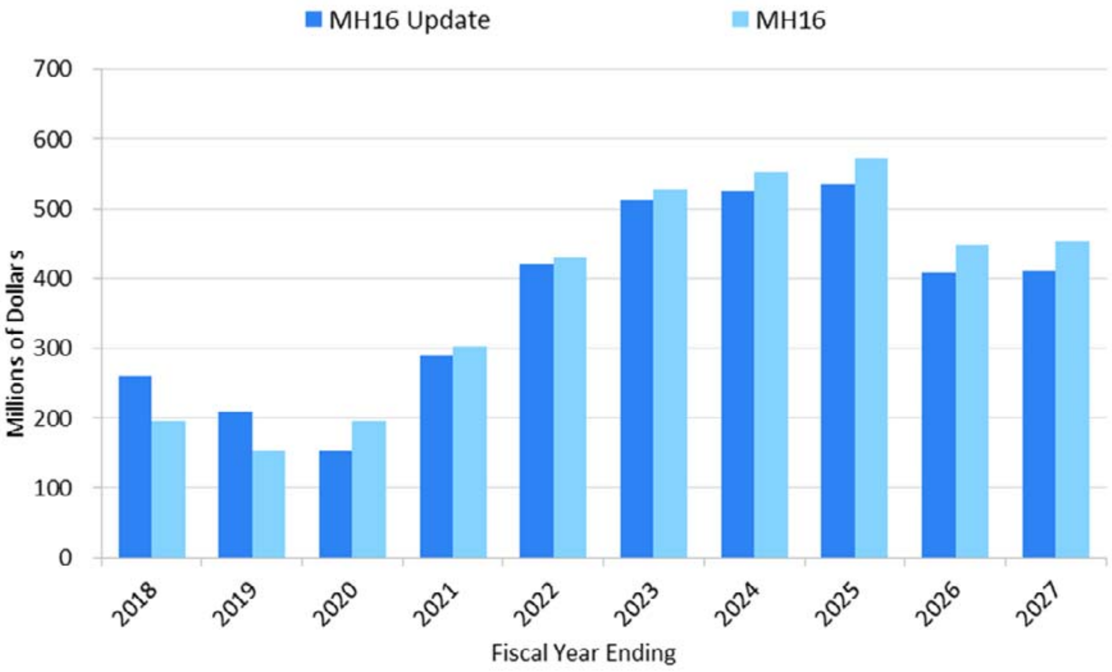


Due to the very wet conditions, hydraulic generation is forecast to be 36.0 TWh in 2017/18 in the MH16 Update, a 1.7 TWh increase over MH16. Thermal generation and purchased energy are forecast to be 1.3 TWh, a 350 GWh reduction over MH16. Net supply is forecast to be 37.3 TWh, a 1.4 TWh increase compared to MH16.

The MH16 Update forecast hydraulic generation for 2018/19 benefits from the expected high storage carry-over from 2017/18. Hydraulic generation is forecast to be 32.8 TWh, thermal generation and energy purchases 2.1 TWh, for net supply of 34.9 TWh. Compared to MH16, this is a 2.0 TWh increase, 167 GWh decrease and 1.8 TWh increase, respectively.

Figure 7 shows a comparison of MH16 and MH16 Update extraprovincial revenues (net of generation costs). Favourable water conditions, discussed above, result in $120 million in higher extraprovincial revenues over the two years 2017/18 and 2018/19 relative to MH16. Over the 10-year period to 2026/27, MH16 Update extraprovincial revenues have decreased by $310 million (net of U.S. exchange). As discussed above, higher net supply in 2017/18 and 2018/19 along with higher export sales resulting from high water conditions in the next two years and lower domestic load over the planning horizon result in an increase in extraprovincial revenues of $131 million over the 10-year period. However, lower export prices more than outweigh the increase in sales volumes resulting in a reduction due to prices of $441 million compared to MH16.

Figure 7. Extraprovincial Revenue Comparison (Net of Generation Costs)



2.6 Economic Outlook

The economic assumptions used in the forecast are based upon Manitoba Hydro's 2017 Economic Outlook, with rate and demographic forecasts as of March 2017. The Economic Outlook forecasts are based on a consensus view of several independent sources including Canada's primary financial institutions and several other independent sources.

5.0 EXTRAPROVINCIAL REVENUE

IFF16 includes the following long-term firm export sales:

Minnesota Power 50 MW System Participation	May 2015	to	May 2020
Minnesota Power 250 MW System Participation	Jun 2020	to	May 2035
Minnesota Power 50 MW ZRC System Participation	Jun 2017	to	May 2020
Great River Energy 200 MW Seasonal Diversity	Nov 2014	to	Apr 2030
Northern States Power 125 MW System Power	May 2021	to	Apr 2025
Northern States Power 375/325 MW System Power	May 2015	to	Apr 2025
Northern States Power 350 MW Seasonal Diversity	May 2015	to	Apr 2025
Northern States Power 75 MW Seasonal Diversity	Jun 2016	to	May 2020
Wisconsin Public Service 100 MW Sale	Jun 2021	to	May 2027
Wisconsin Public Service 108 MW System Participation	Jun 2016	to	May 2021
SaskPower 100 MW System Participation	Jun 2020	to	May 2040
SaskPower 25 MW System Participation	Nov 2015	to	May 2022
American Electric Power 79 MW ZRC	Jun 2016	to	May 2018
American Electric Power 50 MW ZRC	Jun 2018	to	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2018	to	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2020	to	May 2021
NextEra 30 MW ZRC Sale	Jun 2015	to	May 2018
NextEra 100 MW ZRC Sale	Jun 2016	to	May 2018

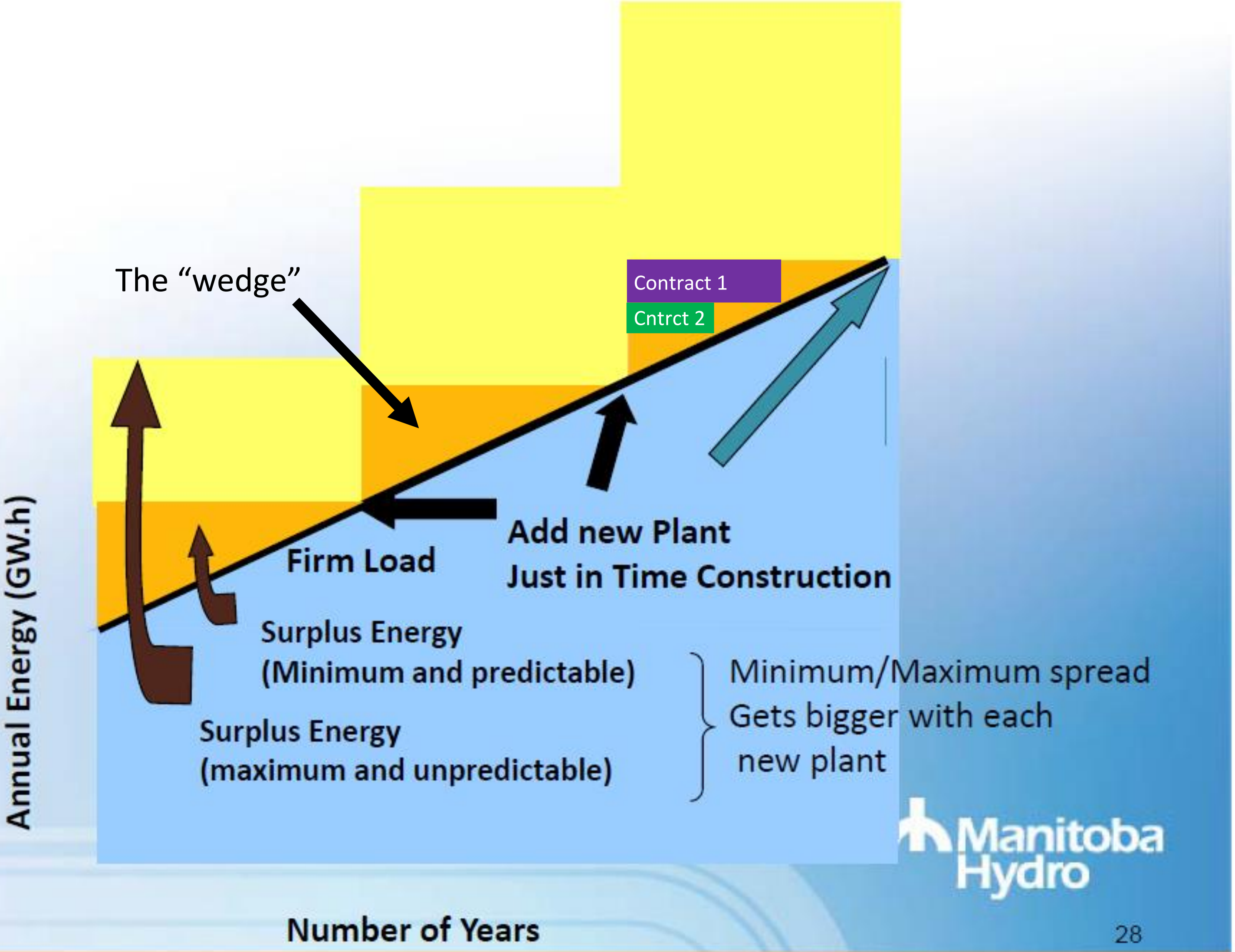
Manitoba Hydro signed a 100 MW Sale Agreement with Saskatchewan Power Corporation for twenty years commencing June 1, 2020 until May 31, 2040. The sale requires the construction of a new 230 kV interconnection with a minimum firm transfer capability of 100 MW. The SaskPower 100 MW sale is at a capacity factor of 57.1% (6x16).

Extraprovincial sales volumes are forecast for the first forecast year (2016/17) based upon the actual inflow conditions and reservoir and lake level elevations as of December 2016 with expected inflows through to the end of the fiscal year. These favourable reservoir and lake level elevations are projected to carry forward into 2017/18 and assume inflow conditions based on the average of 102 water flow records. For 2018/19 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 102 years (1912/13 to 2013/14).

Over the 11-year forecast period, net extraprovincial revenues (extraprovincial revenue net of water rentals and assessments and fuel and power purchased) decreases approximately $0.7 billion compared to IFF15. The decrease in net extraprovincial revenues is mainly comprised of

60

Build to Serve Manitoba Need



Manitoba Hydro

Source: COSS Exhibit MH-20 p.28 with PUB Advisor additions

REFERENCE:

Tab 3 Page 14 of 22

PREAMBLE TO IR (IF ANY):

"In addition, the premium that has historically been applied to the long-term dependable forecast prices has been removed as the achievability of this premium has reduced significantly in the MISO market. Reflecting the continuing trend of low capacity value, a January 2017 update removed capacity value from the pricing of potential future uncommitted export sales from surplus dependable energy."

QUESTION:

a) Please show how the dependable energy premium and the capacity premium that was previously assumed in Manitoba Hydro's export price forecast was calculated or determined.

b) Please provide tables that show the forecasts of dependable energy premiums and capacity premiums for each year to 2034/35 based on the previously assumed methodology.

c) Please provide the forecasts that were made in 2012/13, 2014/15, and the most current forecast.

RATIONALE FOR QUESTION:

To understand the impact of the change in methodology on the export price and revenue forecasts (as opposed to the change in forecast prices).

RESPONSE:

Based on the rational for this question outlined above, Manitoba Hydro prepared this response to explain the net revenue impact associated with the change in planning assumptions.

Response to parts a) to c):

The value of generation capacity is not a premium but rather the value of generation capacity as a component of the long-term dependable product price. Prior to 2016, the value of generation capacity was based on the value in the electricity export price forecast as provided by the independent price forecast consultants, which as discussed below is confidential and commercially sensitive. The dependable product premium was based on Manitoba Hydro's experience in the export market related to prices obtained from long term sales of capacity and energy in comparison with the export price forecast used at the time of the sale.

Prior to 2016, this surplus dependable energy and capacity was assumed to be marketed as a long-term firm export sale of energy and capacity (dependable product). For the MH16 and MH16 Update forecasts, it was assumed that surplus dependable energy was marketed as opportunity energy.

The analysis in the tables below is provided for four financial forecasts: NFAT (for the 2012/13 financial forecast), IFF14, MH16 and MH16 Update.

Table 1 provides net revenue impacts related to the change in planning assumptions. These impacts are calculated as:

Net Revenue Impact	**=**	**Net Revenue (Surplus Dependable Energy as Long-Term Sale)**	**minus**	**Net Revenue (Surplus Dependable Energy as Opportunity)**

The net revenue impact implicitly includes value of the energy sales net of any additional energy costs, such as thermal generation or imports during a drought, to support the firm sale.

Table 1(a) includes the long-term dependable product premium

Table 1(b) excludes the long-term dependable product premium

The capacity revenue cannot be isolated in this calculation due to the interrelationship with the additional costs needed to support the long term sale.

Table 2 presents the differences between Table 1(a) and 1(b) which can be viewed as the potential value of the long term dependable product premium.

The Totals in Table 1(b) can be viewed as the potential value of capacity, net of the additional costs to make a long term sale of capacity and energy.

The positive net revenue impacts in Table 1(a) and Table 1(b) demonstrate the overall incremental value of long-term sales. In some years, a negative incremental difference occurs. The negative incremental difference occurs during periods of significant system changes are primarily due to the difference in the requirements for drought support to serve long term sales.

Manitoba Hydro notes that vast majority of the potential incremental capacity and long term dependable product premium revenue in comparison with previous assumptions comes from the 2022/23 fiscal year and beyond. Manitoba Hydro has relatively small levels of unsold long term dependable energy and capacity until Keeyask comes into service.

Table 1(a), Table 1(b) and Table 2 contain confidential information related to and/or derived from the electricity export price forecast. Public disclosure of the information in these tables would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

Table 1 Net Revenue Impact Related to the
Change of Planning Assumptions for Surplus Dependable Energy
Net Revenue Impact Calculated as: Net Revenue Differential (Long-Term Dependable Minus Opportunity)
(Millions of Nominal Canadian Dollars)

(a) Include Dependable Product Premium for All Forecasts

Fiscal	Reference Report for Net Revenue Impact			
Year	NFAT	2014	MH16	MH16 Update
2014/15	[redacted]	[redacted]	[redacted]	[redacted]
2015/16	[redacted]	[redacted]	[redacted]	[redacted]
2016/17	[redacted]	[redacted]	[redacted]	[redacted]
2017/18	[redacted]	[redacted]	[redacted]	[redacted]
2018/19	[redacted]	[redacted]	[redacted]	[redacted]
2019/20	[redacted]	[redacted]	[redacted]	[redacted]
2020/21	[redacted]	[redacted]	[redacted]	[redacted]
2021/22	[redacted]	[redacted]	[redacted]	[redacted]
2022/23	[redacted]	[redacted]	[redacted]	[redacted]
2023/24	[redacted]	[redacted]	[redacted]	[redacted]
2024/25	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]
Total	528.6	542.2	1093.9	1108.8

3a, b

5c

(b) Exclude Dependable Product Premium for All Forecasts

2014/15	[redacted]	[redacted]	[redacted]	[redacted]
2015/16	[redacted]	[redacted]	[redacted]	[redacted]
2016/17	[redacted]	[redacted]	[redacted]	[redacted]
2017/18	[redacted]	[redacted]	[redacted]	[redacted]
2018/19	[redacted]	[redacted]	[redacted]	[redacted]
2019/20	[redacted]	[redacted]	[redacted]	[redacted]
2020/21	[redacted]	[redacted]	[redacted]	[redacted]
2021/22	[redacted]	[redacted]	[redacted]	[redacted]
2022/23	[redacted]	[redacted]	[redacted]	[redacted]
2023/24	[redacted]	[redacted]	[redacted]	[redacted]
2024/25	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

Table 2 Revenue Estimates Associated with the Dependable Product Premium (Millions of Nominal Canadian Dollars)

Fiscal	Reference Report for Revenue Estimates of Dependable Product Premium			
Year	NFAT	2014	MH16	MH16 Update
2014/15	[redacted]	[redacted]	[redacted]	[redacted]
2015/16	[redacted]	[redacted]	[redacted]	[redacted]
2016/17	[redacted]	[redacted]	[redacted]	[redacted]
2017/18	[redacted]	[redacted]	[redacted]	[redacted]
2018/19	[redacted]	[redacted]	[redacted]	[redacted]
2019/20	[redacted]	[redacted]	[redacted]	[redacted]
2020/21	[redacted]	[redacted]	[redacted]	[redacted]
2021/22	[redacted]	[redacted]	[redacted]	[redacted]
2022/23	[redacted]	[redacted]	[redacted]	[redacted]
2023/24	[redacted]	[redacted]	[redacted]	[redacted]
2024/25	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

3a, b
5c

Notes: The revenues are calculated as the product of the dependable premium multiplied by the quantity of surplus dependable energy.

The above revenues are embedded in the overall revenue estimates for the NFAT and 2014 forecasts.

The above revenues were not included in the overall revenue estimates for the MH16 and MH16 Update forecasts. They are included herein for comparison purposes.

REFERENCE:

PUB/MH I-50

PREAMBLE TO IR (IF ANY):

In the response to PUB/MH I-50, Manitoba Hydro states: “Manitoba Hydro notes that vast majority of the potential incremental capacity and long term dependable product premium revenue in comparison with previous assumptions comes from the 2022/23 fiscal year and beyond. Manitoba Hydro has relatively small levels of unsold long term dependable energy and capacity until Keeyask comes into service.”

QUESTION:

Please complete the following table.

		5 Year Total		10 Year Total		20 Year Total	
1	Contracted Surplus Dependable Energy for Export	__GWh	__%	__GWh	__%	__GWh	__%
2	Uncontracted Surplus Dependable Energy for Export	__GWh	__%	__GWh	__%	__GWh	__%
3	Total Surplus Dependable Energy for Export [1+2]	__GWh	100%	__GWh	100%	__GWh	100%
		5 Year Average		10 Year Average		20 Year Average	
4	Contracted Surplus Capacity for Export at Winter Peak	___MW	__%	___MW	__%	___MW	__%
5	Uncontracted Surplus Capacity for Export at Winter Peak	___MW	__%	___MW	__%	___MW	__%
6	Total Surplus Capacity for Export at Winter Peak [4+5]	___MW	100%	___MW	100%	___MW	100%

RATIONALE FOR QUESTION:

RESPONSE:

The data requested is included (with additional detail) in Table 1 below.

Manitoba Hydro would like to clarify that the quote in the Preamble to this question was meant to highlight that in regard to the potential Total Revenue publically provided in Table 1 of PUB/MH I-50a-c, the timing of potential Total Revenue was primarily from the period of the 2022/23 fiscal year and beyond.

Table 2 provides a breakdown of the timing of the Uncontracted Surplus Dependable Energy and Surplus Capacity by five year periods over the 20 year period. Only 12% of the 20 year total surplus dependable energy and 14% of the 20 year total surplus capacity is available in the first five year period. From a revenue perspective, less than 12% of the potential Total Revenue provided in Table 1 of PUB/MH I-50a-c is in the first five years. It should be noted that the energy price forecasts rise in real dollars, and the rise over the forecast horizon is even more pronounced when expressed in the nominal dollars provided. Both these factor further contribute to the timing of potential Total Revenue being primarily from the period of the 2022/23 fiscal year and beyond.

Table 1: Breakdown of Surplus Dependable Energy/Capacity for Export

	ENERGY	**First 5 Years** **Total** **2017/18 - 2021/22**		**Second 5 Years** **Total** **2022/23 - 2026/27**		**Final 10 Years** **Total** **2027/28 - 2036/37**		**5 Year Total**		**10 Year Total**		**20 Year Total**	
		GWh	**%**	**GWh**	**%**	**GWh**	**%**	**GWh**	**%**	**GWh**	**%**	**GWh**	**%**
1	Contracted Surplus Dependable Energy for Export	18,282	77%	18,593	49%	16,082	42%	18,282	77%	36,876	60%	52,957	53%
2	Uncontracted Surplus Dependable Energy for Export	5,600	23%	19,059	51%	22,370	58%	5,600	23%	24,658	40%	47,028	47%
3	Total Surplus Dependable Energy for Export [1+2]	23,882	100%	37,652	100%	38,452	100%	23,882	100%	61,534	100%	99,986	100%
	CAPACITY	**Average** **2017/18 - 2021/22**		**Average** **2022/23 - 2026/27**		**Average** **2027/28 - 2036/37**		**5 Year Average**		**10 Year Average**		**20 Year Average**	
		MW	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
4	Contracted Surplus Capacity for Export at Winter Peak	776	74%	720	50%	300	37%	776	74%	748	60%	524	51%
5	Uncontracted Surplus Capacity for Export at Winter Peak	277	26%	724	50%	502	63%	277	26%	501	40%	501	49%
6	Total Surplus Capacity for Export at Winter Peak [4+5]	1,053	100%	1,444	100%	802	100%	1,053	100%	1,248	100%	1,025	100%

Table 2: Timing of Uncontracted Surplus Dependable Energy/Capacity for Export [Lines 2 and 5 from Table 1]

		First 5 Years	Second 5 Years	Third 5 Years	Forth 5 Years	
ENERGY		**Total 2017/18 - 2021/22**	**Total 2022/23 - 2026/27**	**Total 2027/28 - 2031/32**	**Total 2032/33 - 2036/37**	**20 Year Total**
Uncontracted Surplus Dependable Energy for Export	**GWh**	5,600	19,059	15,473	6,897	47,028
	%	12%	41%	33%	15%	100%
CAPACITY		**Average 2017/18 - 2021/22**	**Average 2022/23 - 2026/27**	**Average 2027/28 - 2031/32**	**Average 2032/33 - 2036/37**	**20 Year Average**
Uncontracted Surplus Capacity for Export at Winter Peak	**MW**	277	724	647	357	501
	% Avg	14%	36%	32%	18%	100%

REFERENCE:

PUB MFR 72 Attachment Page 35 and 36 of 615

PREAMBLE TO IR (IF ANY):

Keeyask capacity is firmly contracted out until “2026+”.

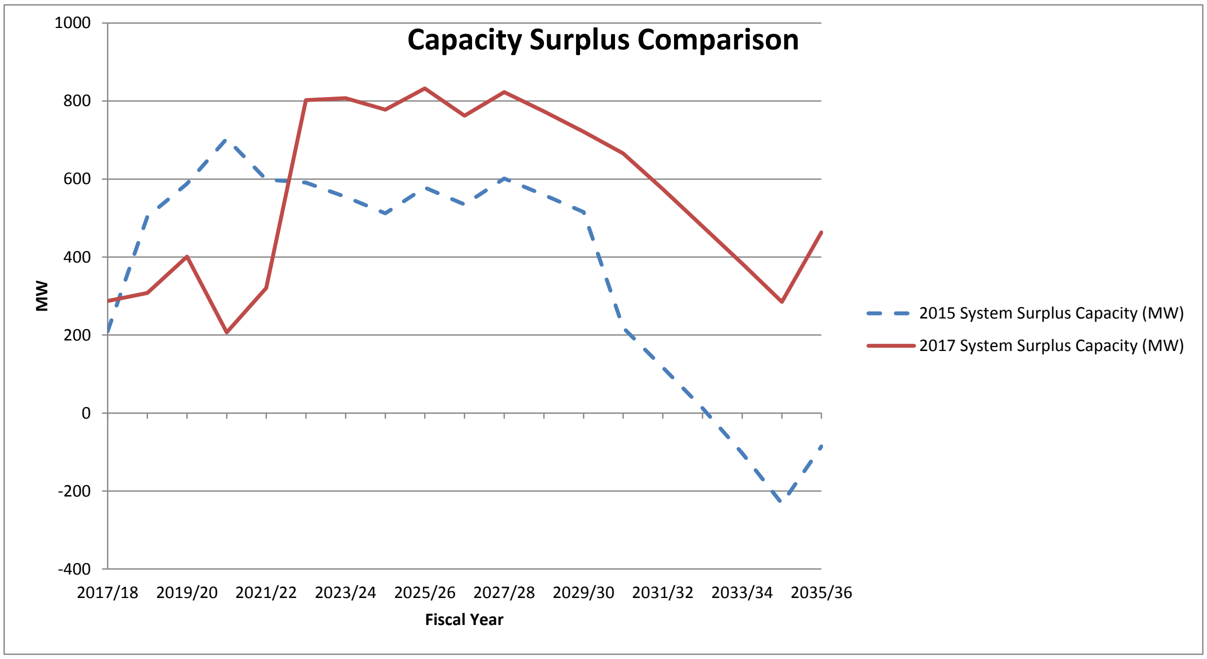
QUESTION:

b) Please confirm whether there is significant surplus capacity in most years from Manitoba Hydro’s existing generation resources, even with Keeyask capacity firmly contracted out.

RATIONALE FOR QUESTION:

RESPONSE:

The following chart shows the winter surplus capacity volumes under the 2015 assumptions (including Keeyask first unit in 2019) and the MH16 Update assumptions (including Keeyask first unit in 2021).



The values from this chart are represented in the table below.

	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
2015 System Surplus Capacity (MW)	210	504	588	704	599	591	554	512	578	535	601	559	516	219	117	12	-103	-232	-86
2017 System Surplus Capacity (MW)	287	308	401	207	321	803	808	778	833	762	823	774	721	666	574	479	383	285	464

The 2015 System Surplus is found in the 2015 Resource Planning Assumptions and Analysis document (filed as Attachment 17 of the 2016/17 Supplemental Filing) and forms the basis for the BCG work.

The 2017 System Surplus can be found in the response to PUB/MH II-45e - the 2017 Resource Planning Assumptions and Analysis document.

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Export revenue enhancement

Executive summary

Interim findings – Aug 9

① **Changes to generation planning policy could increase Dependable Energy supply although would not change available capacity**

- Export contracts currently require both capacity and energy to secure market premium
- Review of Manitoba's future net load and planning criteria could postpone capital requirements

② **Financial forward contracts would reduce market-priced export sales volatility risk**

- Near-term increases in MH surplus energy emphasize need to decrease volatility
- Dynamic modeling of US market price spreads could uncover additional opportunities

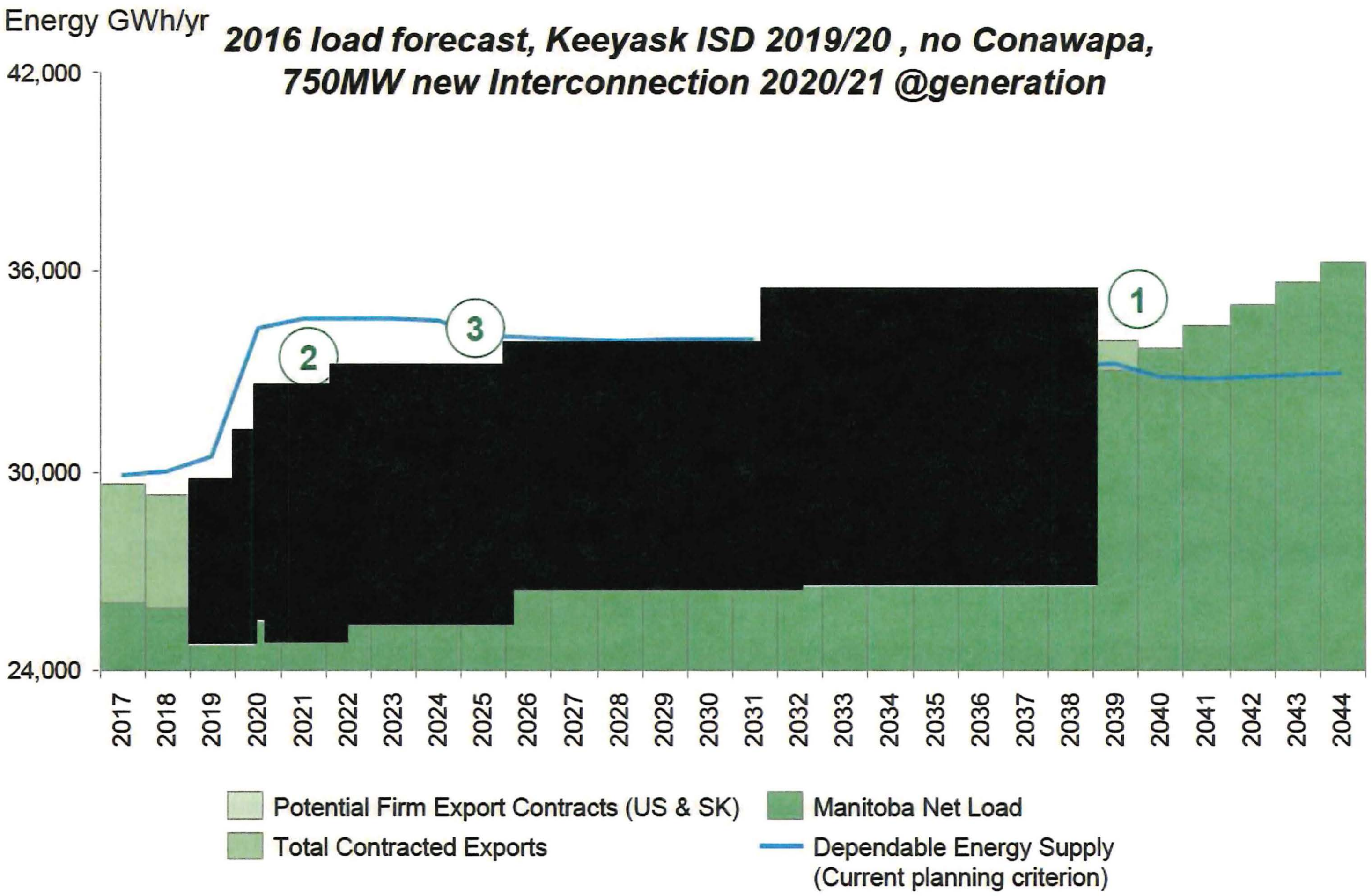
③ **MH's hydro resources would benefit from changes to MISO and US energy policies**

- MISO not currently valuing all existing portfolio attributes of Manitoba generation
- CPP could enable sale of MH's surplus hydro energy - even without capacity - at an additional [redacted]

④ **Saskatchewan current generation needs and MH supply provide also short-term opportunity**

- [redacted]
- [redacted] opportunity to Manitoba as neighbor

Dependable energy supply and projected demand show opportunities in short and long-term



2016 load forecast, Keeyask ISD 2019/20 , no Conawapa, 750MW new Interconnection 2020/21 @generation

[redacted]

① ***Updated planning criteria*** for future supply and demand could delay capital requirements

② Surplus Dependable Energy could be sold under a 5-year ***financial hedging model*** to limit risk

③ Changes in ***MISO policies and approval of CPP*** could increase value of portfolio regardless of capacity

④ Saskatchewan [redacted]

[redacted]

① Capacity constraints limit additional exports revenues above market-priced energy under current market dynamics

Capacity and energy are <u>both</u> required for firm export contracts <u>with premium</u>

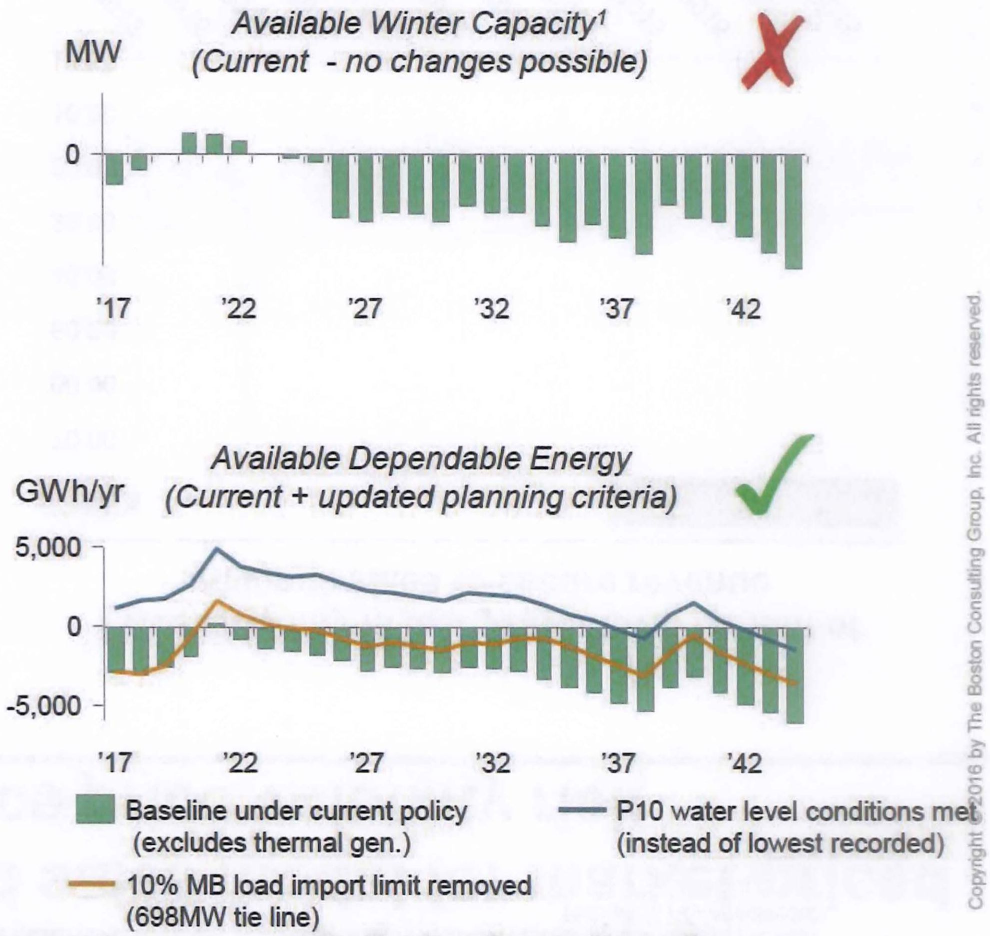
Capacity

- Allows for counterparties to ensure adequate supply for long-term resource planning
- Available capacity is determined by:
  - Peak-load plus 12% reserve margin (industry standard)
- Capacity obligations usually [redacted]

Energy

- Allows for counterparties to meet actual needs during a specific block of time
- Energy obligations are priced either at a firm value or at a market-clearing price
- Dependable Energy is determined by:
  - Energy needed to meet the lowest recorded water supply
  - Imports limited to: amount of energy available during Off Peak and cannot exceed the quantity of export contracts + 10% Manitoba load

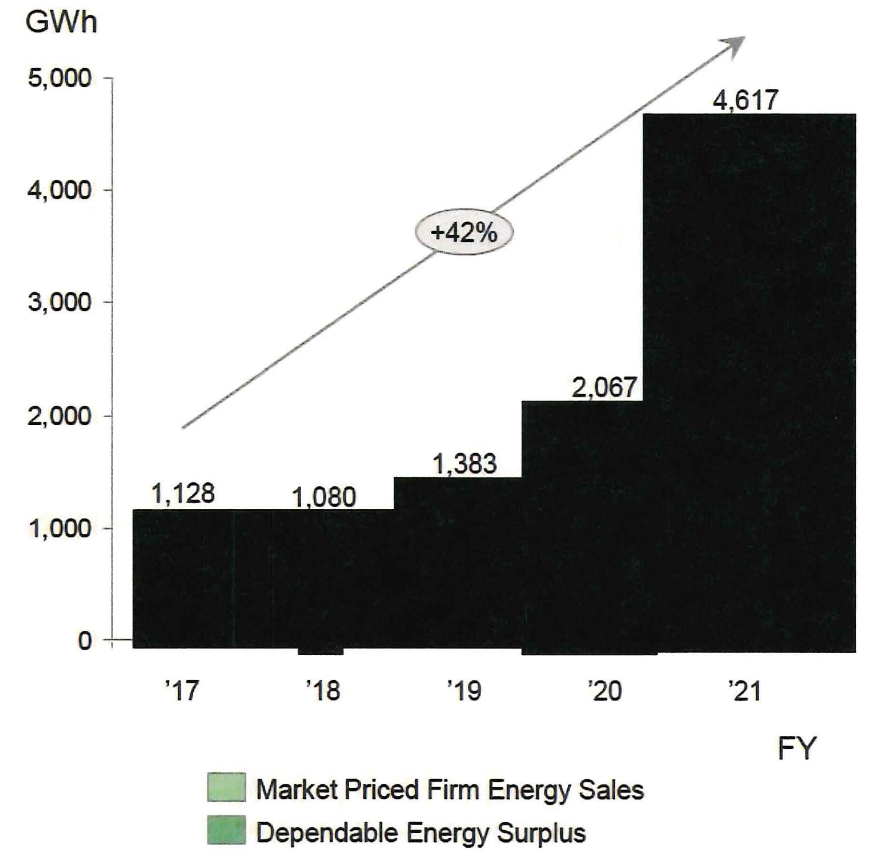
Changing planning criteria does not increase available capacity, only energy



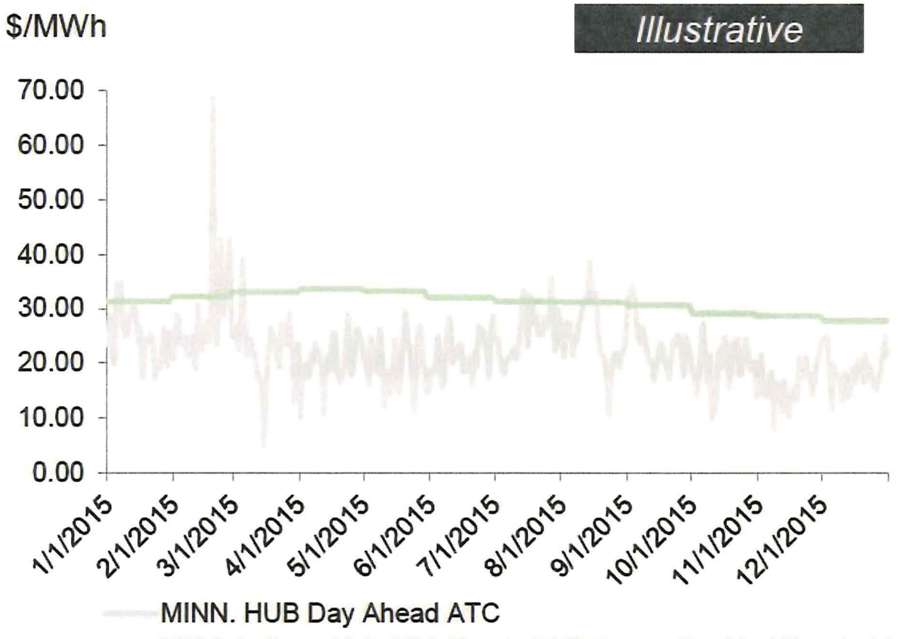
1. Excludes thermal generation. Includes Manitoba net load, firm contracts, potential firm contract

② Implementing a financial forward sales model for market-priced energy is recommended to reduce price volatility risk

Wholesale energy increases in next 5 years due to surplus DE and market contracts



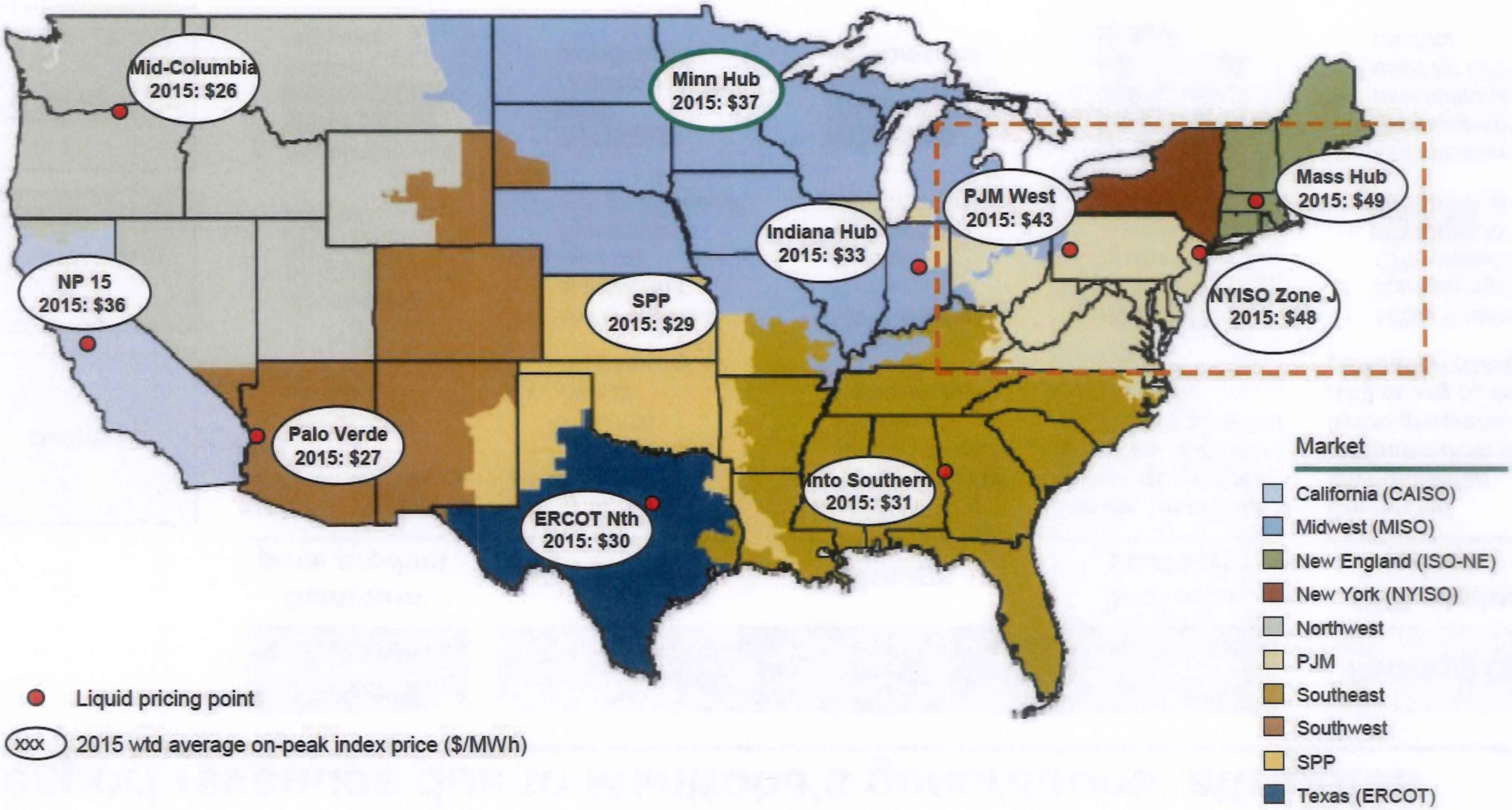
Price volatility in last year shows benefit of advance sales to secure revenue



	'17	'18	'19	'20	'21
Hedge %	80%	70%	60%	50%	40%
Energy Hedged (GWh)	902	756	830	1034	1847
Energy Unhedged (GWh)	226	324	553	1034	2770

Source: Manitoba Hydro "2016 07 20 Dependable Energy with Market Priced Energy", SNL.com

② Opportunities to optimize US market-priced export sales exist outside of MISO but transmission costs can reduce spread



Source: Federal Energy Regulatory Commission, *State of the Markets Report, 2015;* Energy Velocity, 2007, SNL.com

Export

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

③ Changes in MISO and passing of CPP in US could increase export revenues due to Manitoba's generations' attributes

	Requires counterparty	*Requires changes in MISO*			*Requires CPP*
	Semi-firm price product	**Ramp**	**Storage**	**Seasonal product[1]**	**CPP product (enviro.)**
Definition	***Semi-firm product with premium above spot prices*** • *60-80% firm energy*	***Ability to ramp generation*** • *1500 MW ramp in 10 min* • *Firm up intermittency*	***Ability for MISO to store energy via MH*** • *MISO to optimize dispatch of stored energy*	***Contracted supply variations between winter and summer*** • *Firm or semi-firm product*	***Contracted environmental attributes from new hydro generation (US) or any hydro generation (CAN)***
Requirement	• *Counterparty to be open for non-100% firm product*	• *MISO system to start valuing ramping* • *Counterparty with firming need*	• *MISO system to start valuing storage* • *Counterparty with firming need*	• *Potential need for import product from contracting party to execute*	• *MISO system to start paying for CPP products* • [redacted] *for CPP products*
Action	• *Negotiation with* [redacted] *establish reference*	• [redacted] • *Negotiation with counterparties*	• [redacted] • *Negotiation with counterparties*	• [redacted]	• *Optimization of contracts where new hydro is used for CPP product*
Incremental Annual Revenue	[redacted]	[redacted]	[redacted]	[redacted] **Detailed on next slide*	[redacted] [redacted]

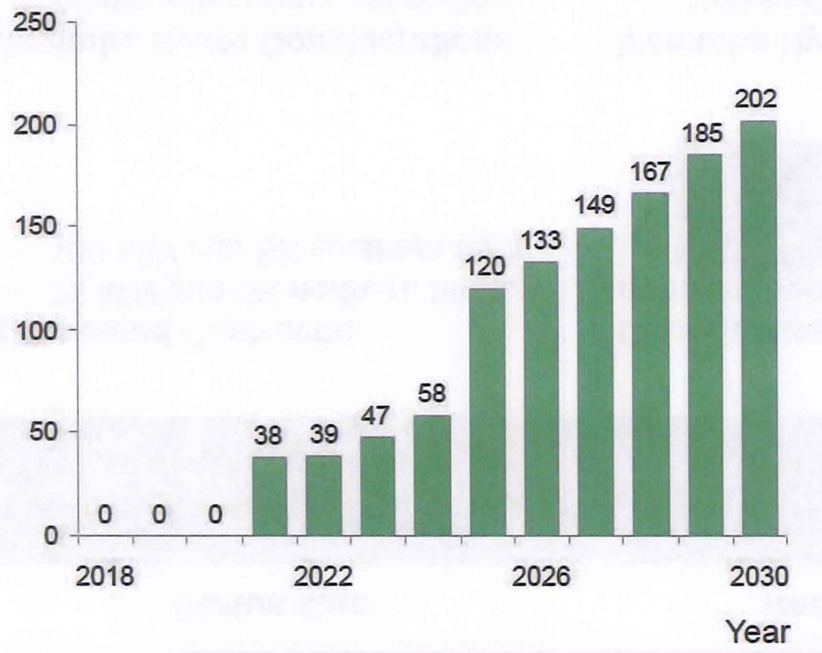
Financial estimates based on MH modeling, knowledge, BCG analysis

1. MISO Seasonal Capacity Construct Change 2. Incremental revenue from surplus energy sales EEPF [redacted] (range dependent on [redacted] % in US) 3. MISO response scenarios to CPP (incremental annual revenue based on $/MWh difference X expected opportunity sales volume; impact modeled in 2025 and 2030

③ Increased monetization of summer capacity for current [redacted] contracts would better optimize MH portfolio

Summer capacity is currently left unsold due to MISO's annual capacity regulations

MH Incremental Summer capacity (MW)[1]



US market examples show that summer capacity is valued at a premium to winter capacity

NYISO Seasonal capacity auction results '15/'16 (USD/kW-mo)

MH could receive an additional [redacted] in average incremental annual revenues if their summer capacity was valued by MISO

Source: SNL.com; MH MISO Seasonal Capacity Construct 1. No surplus when seasonal diversity contracts have optimized capacity; The low end of the range assumes that MH would achieve the monthly capacity price for 4 months over the summer season where the high end of the range assumes MH would achieve for 12 months

④ Saskatchewan provides opportunities for Manitoba due to its limited market access and domestic needs

Status Quo

Current Contracts

2 Executed Contracts:
- 25 MW into SK northern territory
- 100 MW into SK southern territory

Manitoba Hydro Considerations

+ Works with current generation
+ [redacted] in export revenues to utilize DE predicted surplus
– $70M CapEx requirement (already included in the base IFF)

Recommendation

Phase 1: Additional 100 MW

Capacity available for new firm contract beginning in '22
- [redacted]

Manitoba Hydro Considerations

+ Works with current generation
+ [redacted]

Incremental Annual Revenue: [redacted]

Decision point

Future State

Phase 2: New Generation Project

New resources required to replace retiring of 1600MW of coal in SK
- [redacted]

Manitoba Hydro Considerations

+ Could reduce cap. need to MH
+ Possible federal subsidies
– [redacted]

Long-term impact only

Decision point

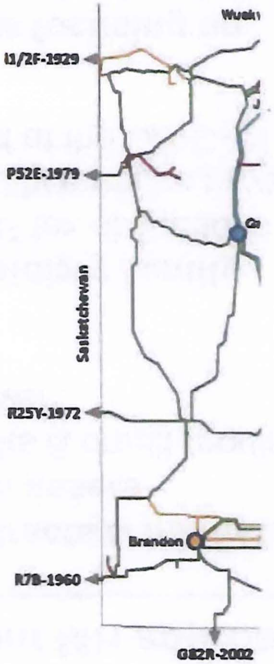
[redacted]

Source: (2016 07 26 new 100 MW sale pricing for SASK); BCG Analysis

Compared to MISO, [redacted] for firm contracts in ④ Saskatchewan, however, transmission limited

Current transmission between SK and Manitoba is limited, utilized by [redacted]

- 4 current interconnections between Manitoba and Saskatchewan
- Northern capacity is filled by 25 MW contract and SPC wheeling reserve (North to South)
- Southern Capacity is used for reserve and access to other markets (MISO)
- Additional 230-kV transmission line to be built in the South between Manitoba and Saskatchewan for 100 MW contract fulfillment



SaskPower price of alternative generation high compared to other neighboring markets

	MISO Alternatives	SaskPower Alternatives[1]	Price Premium in SK
	Average (CAN$/MWh)	Range (CAN$/MWh)	Average (CAN$/MWh)
Wind	$28.80[4]	[redacted]	[redacted]
Combined Cycle Gas	[redacted]	[redacted]	[redacted]
100MW Firm Contract w/ MH[5]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

REFERENCE:

PUB MFR 72 Attachment Pages 225 to 231 of 615; Coalition/MH I-81b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please elaborate on the potential changes to generation planning policy that could increase dependable energy supply and enhance export revenues, as identified in PUB MFR 72 Attachment page 225.

b) Please explain whether Manitoba Hydro has considered contracting for the sale of surplus dependable energy under a shorter term financial hedging model, and how such a transaction would be executed, as mentioned on page 226.

c) Please confirm whether the summer to winter capacity value differential shown on page 231 means that Manitoba Hydro's capacity exchange contracts provide more value to the U.S. counterparties than they do to Manitoba Hydro.

d) Please explain how the MISO summer capacity regulations result in Manitoba Hydro not being able to sell all of its surplus summer capacity, which for the next three years ranges from 143 MW to 363 MW.

e) Please explain the steps Manitoba Hydro is taking or has taken to attempt to have its surplus summer capacity valued by MISO.

RATIONALE FOR QUESTION:

RESPONSE:

The export revenue enhancement concepts described on Page 225 of 615 of PUB MFR 72 Attachment [BCG Analysis] were identified by Manitoba Hydro prior to and independent of BCGs work.

a) The potential changes in the generation planning criteria referenced in the BCG report (page 225 of PUB MFR 72 Attachment) are related to a potential increase, further out on the planning horizon, in the quantity of imports considered as dependable energy. The changes Manitoba Hydro is considering could potentially defer the need for new resources for the Manitoba load around the 2040 time frame, as indicated by the positioning of the number 1 on page 226 of 615 in PUB MFR 72 Attachment in the year 2039, and the statement on the slide that "Updating for future supply and demand could delay capital requirements".

b) As a regular course of business Manitoba Hydro sells surplus energy in the forward markets at a fixed price, hedging away the risk associated with pricing in the spot market. These forward sales when combined with spot market sales are included in Manitoba Hydro's opportunity sales results. Generally these forward sales are limited to the near time and are backed by hydraulic energy based upon Manitoba Hydro's expected flow and storage conditions.

   An alternative is to enter into a financial contract for fixed price energy sometime into the future and take the risk that under unfavorable water conditions, when hydraulic generation is insufficient to fulfill the obligation, the obligation would have to be satisfied by purchasing energy from the market and exposing Manitoba Hydro to a potential loss if the market price is higher than the forward price.

   Manitoba Hydro has entered into a few small longer term financial energy contracts. However there is a very limited market for this product at the current time, given the dramatic reduction in price volatility that has been experienced as a result of increased natural gas supplies.

c) The referenced chart illustrates 2015/16 capacity auction prices in the NYISO, and does not reflect the cost of building capacity to serve load over the long term.

   Manitoba Hydro's long term capacity exchange contracts allow it to avoid constructing and maintaining over 600 MW of generation capacity to meet winter peak and capacity reserve requirements in Manitoba. They provide our US counterparties with at least 550 MW of generation capacity to meet summer peak and reserve requirements.

Under these contracts no money is exchanged as it is assumed that the avoided cost of building an alternative capacity resource over the term provides equivalent benefits to each party.

However, because Manitoba Hydro generally is energy constrained and builds new generation to meet its dependable energy criterion, Manitoba Hydro receives the additional benefit associated with having access to dependable energy in the off peak hours that is made possible as a result of the firm import transmission capability that is required in order to exchange capacity. This benefit is not applicable to utilities in the MISO market as they are not subject to the risk of energy shortages due to drought. On that basis it could be argued that Manitoba Hydro is receiving more benefits from the capacity exchanges than its counterparties.

d) At this time, the MISO capacity construct (market/ resource adequacy requirements) is annual. This precludes Manitoba Hydro from selling a summer only capacity product.

e) Manitoba Hydro has participated in the MISO Stakeholder process in support of implementing a two season resource adequacy construct. However, MISO has recently decided to move away from this effort and refocus on aligning the overall MISO market availability and need for capacity resources to enhance reliability and away from winter reliability concerns.

in addition to what we've already committed to Wisconsin, is -- is in the United States. And -- and until the EPA clarifies what the rules are under the Clean Power Plan, and until the states say what their implementation plans are going to be, utilities don't know what to do. They need to know what the rules are.

And so to have a large US utility say today that, We're going to commit to -- to a large power purchase from Manitoba Hydro, they can't, because the ground is shifting. And so, you know, we can have discussions, but no one is going to commit to a term sheet with Manitoba Hydro at -- at this point until that -- that clarity is received.

And there is -- there is demand in Saskatchewan and we're working with them, but that demand isn't sufficient at this point to trigger Conawapa. So it -- it will -- it will take us several years to -- to have some clarity so that a -- a US customer can say, You know, this is -- this is the right thing for our customers; it's consistent with -- with the regulatory requirements of the federal government and the state governments. And only then would -- would they -- would they commit to signing some agreement with Manitoba Hydro.

MR. BOB PETERS: It sounds like for all

of those things to settle down, Mr. Cormie, it takes us out to closer to 2020 or beyond?

MR. DAVID CORMIE: What -- what's happening in addition to that though, Mr. Peters, is that there's a huge amount of coal generation in Minnesota that has to retire. And so when you look at the supply and demand situation for the State of Minnesota by 2030, it becomes very precarious. The nuclear plants are reaching the end of their life. Most of the coal is shut down. You can't run a state electricity system on wind and solar power. It won't work.

You need base load resources. And so, you know, that's where Manitoba Hydro brings value to the table. And if we wait till 2020, we can't meet the need in 2030. It takes ten (10) years to build Conawapa. It will take maybe five (5) years to get through the regulatory process, to go through the environmental things, to come before a panel such as this to do the business case of Manitoba.

So, you know, as I said, a couple years. If we don't have something in a couple years, it -- Conawapa won't be triggered by something in the United States. It -- it essentially will fall off the table as an opportunity to solve the issues that the State of

Minnesota has.

It doesn't mean that Conawapa won't be -- be built, but it'll be built based on the need in Manitoba. That's something like Mr. Miles said, out in 2037 we're starting to run short of -- of resources, so the question is: Do we build it for Manitoba? Not because we're building it as -- based on a business case that I've been able to put together with some -- some export customers.

2020 is too late. And we've told our customers, and the regulators, and the politicians, the United States, if you think that Manitoba Hydro will be part of the solution to meeting the EPA requirements in 2030, you need to tell us now, because it's going to take many years for us to prepare and to build that plant, so that by the time you get to 2030, or 2031, or 2032, that we can help you.

MR. BOB PETERS: Mr. Cormie, has Manitoba Hydro ruled out Conawapa as a merchant plant?

MR. DAVID CORMIE: Well, that -- that's what I've been talking about. Building a business case so that the risks of -- of Conawapa aren't borne -- of Conawapa advancement aren't borne by the domestic customers. There has to be enough of -- of firm commitments so that, you know, if the risk of building the plant isn't -- isn't borne by -- by the -- the costs of -- of advancing Conawapa for ten (10) years is fully borne by the people who are buying the power.

And -- and fundamentally, that was the problem with the case that -- that was presented at the NFAT, is that we were only halfway through that process of -- of bringing the customers to the table. And that's why we weren't asking for approval of Conawapa. We weren't prepared to reach a segment. We're -- we're going down that path.

And we would only come to the -- to the Board when the business case was robust and that -- that the uncommitted portion of the output of the plant wasn't -- the risk of that weren't being borne by the customers. So we're -- we're working on that, but it'll take several years for it to happen.

MR. BOB PETERS: Thank you. Turning to page 160 of the book of documents, Exhibit PUB-20, there's a number of listings here of export contracts after 2015, Mr. Cormie and Mr. Miles, that are considered dependable from an energy perspective. Page 160. Thank you.

I'm going to ask if there could be an undertaking from you gentlemen to quantify the dependable energy required under each of the listed

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$453M Manitoba Hydro line to Minnesota could face delay after energy board recommendation

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National Energy Board recommends lengthier 'certificate' approval process for transmission project

By Cameron MacLean, CBC News Posted: Nov 04, 2017 4:00 PM CT Last Updated: Nov 04, 2017 5:35 PM CT

A recommendation from the National Energy Board could push back the construction start date of a $453-million hydroelectric transmission line from Manitoba to Minnesota.

In a letter to federal Natural Resources Minister Jim Carr, the regulatory agency recommends using a "certificate" approval process, which could take more time than the simpler "permit" process Manitoba Hydro favours.

The certificate process involves public hearings to weigh the merits of the project, which would then go to the federal cabinet for approval.

The NEB says this process would allow for more procedural flexibility and "address Aboriginal concerns that may arise in the circumstances of this process."

- Manitoba makes hydro power deal with U.S. utility

- Hydro chooses final preferred route for Manitoba-Minnesota Transmission Project

The Manitoba-Minnesota Transmission Project would provide the final link in a chain that brings hydroelectricity from generating stations in northern Manitoba, through the Bipole III transmission line and across the U.S. border as part of a 308-megawatt deal with the Green Bay-based Wisconsin Public Service.

When Hydro filed its application in December 2016, it had expected to have approval by the end of August 2017 and to begin construction on the line in mid-December, in order to have the line in operation by May or June 2020.

Groups representing stakeholders along the proposed route of the transmission line had mixed reactions to the energy board's recommendation.

A lawyer representing a coalition of more than 120 landowners in the Rural Municipality of Taché and around La Broquerie, Man., welcomed the opportunity to have a more "fulsome" discussion about the project.

- Manitoba Hydro moves to purchase land for $350M transmission line before approval

"I think it's a positive step. As people become more familiar with the project, the deficiencies with it become more obvious," said Kevin Toyne, who represents the Southeast Stakeholders Coalition.

Toyne said some coalition members are worried that Hydro will forcibly expropriate land in order to build the line, while others are worried about potential economic and health impacts of having the line so close to their homes. They have proposed moving the line farther east.

When the Clean Environment Commission — an arm's-length provincial government agency — held public hearings on the proposed route earlier this year, the coalition brought their concerns forward, but Toyne says both the commission and Hydro ignored them.

Hydro still aiming for 2020 in-service date

The Manitoba Métis Federation also participated in those public hearings. MMF president David Chartrand worries about the impact a possible delay could have on revenue from sales of hydroelectric power to the U.S.

"I know that a lot of money, billions have been invested on this line. And if the connection line is not done, then of course this will be sitting here, not gaining any revenue, which will affect every Métis in this province, given our Hydro bill's going to go up," Chartrand said.

- What Manitoba Hydro's gamble means for your rates

The NEB letter to Minister Carr requests that he "determine this matter in an expedited manner."

Manitoba Hydro spokesperson Bruce Owen said in an email that the Crown corporation will participate in whatever process, permit or certificate, the NEB takes.

"Manitoba Hydro does not have any information at this point in time that would change the estimated in-service date (May-June 2020) for the Manitoba-Minnesota Transmission Project," he said.

The federal government "is currently reviewing the NEB's recommendation to designate the project as subject to a certificate, which would result in public hearings," said Alexandre Deslongchamps, a spokesperson for Carr.

"Under the *National Energy Board Act*, an international power line requires either the approval by the NEB through a permit or approval by the Government of Canada by a certificate. Both must be issued by the NEB," he wrote in an email to CBC News.

By law, the certificate process is not to take longer than 15 months.

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Agreements with MP leave options in case of construction delays; outcomes in event of cancellation more uncertain

Action	Cause	250 MW Sale	133 MW Sale
Delay	**Keeyask**	**Sale begins in 2020 unless agreement amended** • MH would source power required to supply 250 MW in early years of delay [redacted]	**Sale unaffected**
	Tie Line	**Contract upheld if MP and MH reach mutual agreement to use alternate transmission**	**Sale delayed until Tie Line ISD**
Cancel	**By MP due to regulatory reasons**	**Sale Cancelled**	**Sale cancelled**
	By MH due to regulatory reasons	[redacted]	**Sale cancelled**
	By MP due to economic reasons	**MH has option to request that MP revert to constructing 230 kV line**	**Sale cancelled**
	By MH due to economic reasons	**Potential for MP to pursue litigation related to costs spent to date, and potential damages for future lost earnings**	**Sale cancelled**

Source: Manitoba Hydro

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5.0 EXTRAPROVINCIAL REVENUE

IFF16 includes the following long-term firm export sales:

Minnesota Power 50 MW System Participation	May 2015	to	May 2020
Minnesota Power 250 MW System Participation	Jun 2020	to	May 2035
Minnesota Power 50 MW ZRC System Participation	Jun 2017	to	May 2020
Great River Energy 200 MW Seasonal Diversity	Nov 2014	to	Apr 2030
Northern States Power 125 MW System Power	May 2021	to	Apr 2025
Northern States Power 375/325 MW System Power	May 2015	to	Apr 2025
Northern States Power 350 MW Seasonal Diversity	May 2015	to	Apr 2025
Northern States Power 75 MW Seasonal Diversity	Jun 2016	to	May 2020
Wisconsin Public Service 100 MW Sale	Jun 2021	to	May 2027
Wisconsin Public Service 108 MW System Participation	Jun 2016	to	May 2021
SaskPower 100 MW System Participation	Jun 2020	to	May 2040
SaskPower 25 MW System Participation	Nov 2015	to	May 2022
American Electric Power 79 MW ZRC	Jun 2016	to	May 2018
American Electric Power 50 MW ZRC	Jun 2018	to	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2018	to	May 2020
Basin Electric 50 MW ZRC System Participation	Jun 2020	to	May 2021
NextEra 30 MW ZRC Sale	Jun 2015	to	May 2018
NextEra 100 MW ZRC Sale	Jun 2016	to	May 2018

Manitoba Hydro signed a 100 MW Sale Agreement with Saskatchewan Power Corporation for twenty years commencing June 1, 2020 until May 31, 2040. The sale requires the construction of a new 230 kV interconnection with a minimum firm transfer capability of 100 MW. The SaskPower 100 MW sale is at a capacity factor of 57.1% (6x16).

Extraprovincial sales volumes are forecast for the first forecast year (2016/17) based upon the actual inflow conditions and reservoir and lake level elevations as of December 2016 with expected inflows through to the end of the fiscal year. These favourable reservoir and lake level elevations are projected to carry forward into 2017/18 and assume inflow conditions based on the average of 102 water flow records. For 2018/19 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 102 years (1912/13 to 2013/14).

Over the 11-year forecast period, net extraprovincial revenues (extraprovincial revenue net of water rentals and assessments and fuel and power purchased) decreases approximately $0.7 billion compared to IFF15. The decrease in net extraprovincial revenues is mainly comprised of

Home > Sector Participants > ... > Compliance Enforcement > Negotiated Settlements

Compliance Enforcement

The IESO's Market Assessment and Compliance Division (MACD) monitors the operation of Ontario's electricity grid and market, investigating potential non-compliance with the Ontario market rules and North American reliability standards. Where appropriate, it enforces the rules by making determinations and imposing sanctions. It may also engage in alternative case resolutions, such as agreeing to settlements. A key goal of enforcement is to encourage compliance which benefits the reliability of the IESO-controlled grid and efficient and fair operations of the IESO-administered markets.

IN THIS SECTION...

Sanctions

Negotiated Settlements

Negotiated Settlements

In some circumstances, MACD may enter into a voluntary negotiated settlement with a Market Participant, rather than issuing formal enforcement actions such as the imposition of a financial penalty. MACD's main objective is to secure the best possible outcomes for both reliability and the market, rather than the enforcement of the rules for its own sake. Accordingly, it may consider whether an alternative resolution, which typically includes a range of mitigation and/or remedial features, is preferable.

Below is a list of negotiated settlements agreed upon by MACD.

2017 Negotiated Settlements

The Independent Electricity System Operator ("IESO") has approved a settlement with The Manitoba Hydro-Electric Board ("Manitoba Hydro") regarding a compliance investigation into Manitoba Hydro's trading activity on the Manitoba and Minnesota interties.

In a Notice of Alleged Breach dated September 13, 2012, staff of the Market Assessment and Compliance Division ("MACD") of the IESO alleged that, from October 2011 to September 2012, Manitoba Hydro may have breached section 3.5.6 of Chapter 7 of the *Market Rules* when its energy offers exceeded the maximum allowed injection permitted under section 3.5.6.3 of Chapter 7 of the *Market Rules*. In a Supplemental Notice of Alleged Breach dated December 4, 2015, MACD staff alleged that the offers that were the subject of the earlier Notice of Alleged Breach were misleading and may have been in breach of section 11.2.1 of Chapter 1 of the *Market Rules*. Further, on December 4, 2015, MACD staff alleged that Manitoba Hydro may have breached section 6.2.6 of Chapter 3 of the *Market Rules* by refusing to answer three questions posed in one of MACD's information requests.

In order to resolve the matter, and without Manitoba Hydro admitting any wrongdoing related to the breaches as alleged by MACD staff, the IESO and Manitoba Hydro have agreed to a settlement.

Manitoba Hydro has agreed to pay CDN $9,600,000.00 to settle the matter.

2016 Negotiated Settlements

Resolute FP Canada Inc. ("Resolute"): On August 22, 2016, pursuant to Chapter 3 of the *market rules,* the IESO issued a non-compliance letter to Resolute FP Canada Inc. ("Resolute") for breach of the requirements of the following provisions of the *market rules:*

1. Chapter 7, section 3.3.8;

2. Chapter 7, section 3.5.6; and
3. Chapter 7, section 7.5.1.

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The IESO's determination relates to Resolute's operation of its dispatchable pulp and paper facilities located in Fort Frances and Thunder Bay, during the period October, 2004 to September, 2013, as applicable. In this regard, the IESO has determined that on certain occasions during the relevant period, Resolute engaged in the following conduct:

1. submitted bid quantities to the IESO in excess of the facility's ability to withdraw energy from the IESO-controlled grid;
2. failed to update dispatch data to be consistent with the reasonable expectations of the quantity of energy to be delivered or withdrawn by the facility; and
3. deviated from the IESO's dispatch instructions.

The non-compliance letter was issued as part of a settlement between the IESO and Resolute. Without acknowledging or admitting any breach of the *market rules*, Resolute has accepted, without contest, the IESO's determinations and has agreed to voluntarily repay the amount of $8,750,000.00. This payment is in addition to an earlier voluntary repayment by Resolute in the amount of $1,825,010.03.

Going forward, Resolute has also agreed to develop and implement an Internal Compliance Program ("ICP") in order to ensure that potential breaches of the *market rules* are detected and corrected. In doing so, Resolute will take into account relevant IESO guidance, including the Statement of Approach published December 19, 2013
(see Internal Compliance Programs). Resolute will implement the ICP within one year of the date of the settlement with the IESO.

2014 Negotiated Settlements

Ontario Power Generation Inc. (OPG) paid the sum of $550,000 to the IESO for its failure, on a timely basis, to remove its offers for Lambton G4 in HE19 on October 15, 2010 as required by Chapter 7, Section 3.3.8 of the Market Rules. The payment addresses financial benefit inadvertently received by OPG, impact to the market and other factors. Along with a lack of intent to breach the rule, MACD notes in particular the timely self-report and other cooperation by OPG regarding the matter.

2013 Negotiated Settlements

Independent Electricity System Operator: On December 17, 2010 the IESO reached a settlement agreement with the Market Assessment and Compliance Division ("MACD"), in relation to a MACD finding that the IESO violated North American Electric Reliability Corporation reliability standards and associated Northeast Power Coordinating Council criteria, and thereby breached the market rules. The agreement stipulated that the IESO agreed to pay a penalty in the amount of $130,000, with $100,000 to be suspended pending MACD's evaluation of agreed improvements to the IESO's internal compliance program. MACD judged that those improvements would be of more value to the shared goal of reliability than a financial penalty, in this circumstance. That evaluation is now complete and the IESO has made the requisite improvements to its compliance program. The corresponding component of the penalty is now removed.

2010 Negotiated Settlements

The IESO has agreed to a settlement with the Market Assessment and Compliance Division ("MACD") in the amount of $130,000 for failure to identify an increased generation loss associated with a single contingency during a Bruce E Bus outage in October 2008. This event was found by MACD to violate North American Electric Reliability Corporation reliability standards and associated Northeast Power Coordinating Council criteria and market rules. An amount of $100,000 is suspended for one year. At that time, the suspension will be made permanent provided the IESO compliance program satisfies effectiveness criteria set out in the settlement.

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St. Joseph Wind Farm as the loan was repaid in November 2015. This was partially offset by an increase in temporary investment income due to higher temporary investment balances resulting from greater pre-funding of long term debt in 2015/16.

2016/17 Outlook vs. 2015/16 Actual

The decrease in finance income was primarily due to lower interest income from the St. Joseph Wind Farm as the loan was repaid in November 2015.

2017/18 Forecast vs. 2016/17 Outlook

The forecast decrease in finance income is primarily due to less interest earned on temporary investments as the average balance of temporary investments is forecast to decrease. This is partially offset by increased interest income from additional loans to the Keeyask partners as construction progresses on the generating station.

2018/19 Forecast vs. 2017/18 Forecast

The forecast increase in finance income is primarily due to additional interest on temporary investments reflecting higher interest rates. In addition, there is higher interest income from loans to the Keeyask partners as construction progresses on the generating station.

6.2.5 Operating & Administrative

Operating and administrative (O&A) expenses are comprised primarily of labour and benefits, materials, contracted services and overhead costs associated with operating and maintaining all facilities of the corporation and providing services to customers.

As part of the corporation’s plans to strengthen Manitoba Hydro’s long term financial health, significant cost reductions have been incorporated in the O&A targets embedded in MH16 for 2017/18 and 2018/19. As discussed in Tab 3, these reductions are expected to be achieved through internal workforce reductions and procurement savings obtained through the Supply Chain Management initiative.

The final results of the corporate restructuring program will have a significant impact on the detailed components of the O&A forecast as the program will ultimately affect the organization’s structure, staffing levels and employee related costs (i.e. salaries, benefits, travel etc.). Over the next number of months, the corporation will be reporting the actual savings achieved as well as associated restructuring costs. Once the corporate restructuring program is complete, detailed O&A budgets will be prepared in support of the new structure and the related responsibilities/accountabilities of the individual areas. As such, all detailed schedules embedded in the application and other filing materials for both the 2017/18 and 2018/19 fiscal years are incomplete.

Figure 6.13 Operating & Administrative

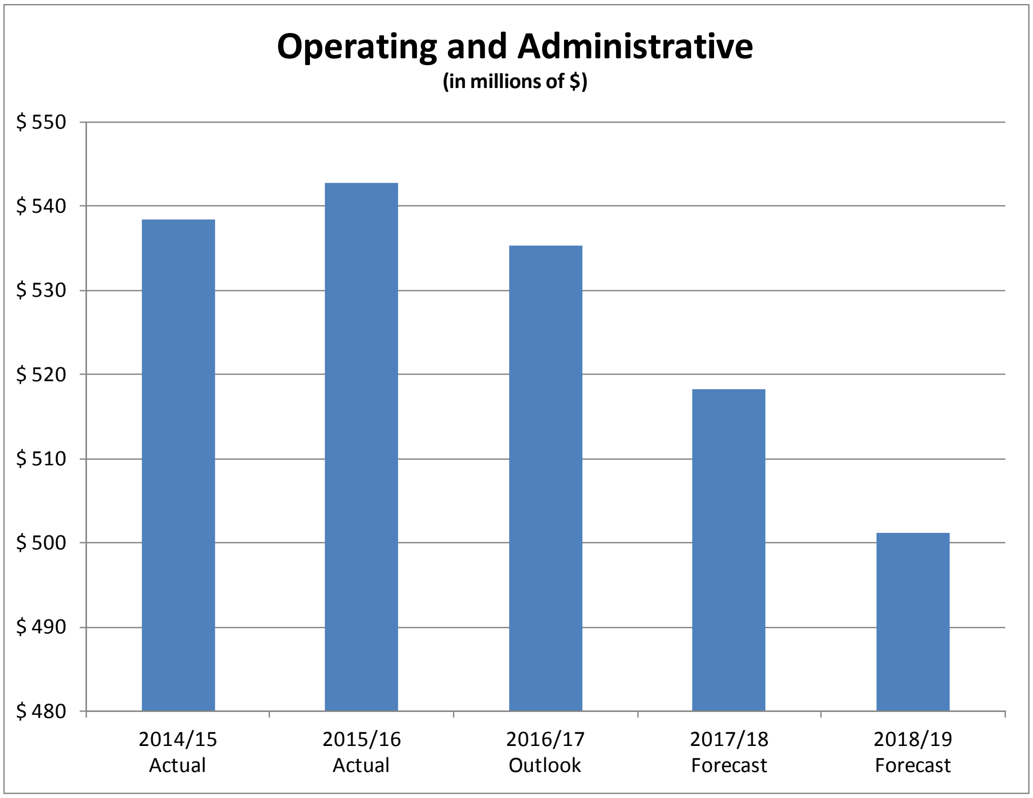

Figure 6.14 Operating and Administrative Expense breakdown

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

	2014/15 Actual	2015/16 Actual	2016/17 Outlook	Average Annual % Inc/(Dec)	2017/18 Forecast	2018/19 Forecast	Average Annual % Inc/(Dec)
Employee related expenditures							
Wages & salaries	$ 493 346	$ 506 811	$ 532 941	3.9%			
Overtime	69 541	67 982	76 975	5.5%			
Employee benefits	166 854	159 363	169 734	1.0%			
Other	73 067	70 832	75 141	1.5%			
Total employee related expenditures	802 809	804 988	854 792	3.2%			
Less: capitalized labor & overhead	(313 931)	(317 387)	(355 908)	6.6%			
Operational employee related expenditures	488 877	487 601	498 884	1.0%			
External services and materials	126 850	128 062	129 160	0.9%			
Donations, sponsorships & grants	2 804	2 592	2 367	-8.1%			
Uncollectible accounts	4 890	5 748	4 218	-4.5%			
Other	452	1 123	138	30.3%			
Cost recoveries	(15 115)	(15 789)	(15 278)	0.6%			
O&A charged to gas operations	(70 355)	(66 607)	(67 818)				
	538 404	542 729	551 670	-1.8%	518 340	501 183	-1.7%
Year end outlook adjustment**	-	-	(16 280)		-	-	
Operating and administrative expenses *	$ 538 404	$ 542 729	$ 535 390	-1.9%	$ 518 340	$ 501 183	-1.8%
Year over year $ change		$ 4 326	$ (7 339)		$ (17 051)	$ (17 156)	
Year over year % change		0.8%	-1.4%		-3.2%	-3.3%	

* Amounts for overhead not eligible for capitalization have been deferred in compliance with PUB Order 73/15 and are reflected in Net Movement

** Year end outlook adjustment - The projection of year-end results for O&A for 2016/17 of $535.4 million was based on an analysis of actual results to the end of January and high level assumptions of spend for February and March. Detailed budgets by department and cost element (e.g. wage & salaries) were not revised to reflect the overall outlook projection given the magitude of the work effort required.

The 1.8% average annual decrease over the 5 year period is primarily a result of forecasted staff reductions combined with an overall focus on cost containment including savings achieved through the supply chain initiative.

The cost containment strategy focuses on a comprehensive management of staff positions across all Corporate and Operating groups. The corporation continues to review work processes and functions to identify opportunities for the elimination of work no longer deemed essential, to consolidate similar functions where overlap may exist, and to implement changes which reduce costs and increase efficiencies.

In addition, the corporation has negotiated new Collective Agreements with AMHSSE, CUPE and Unifor which include lower wage settlements beginning January 1, 2017 through to December 2020 as shown in **Figure 6.15** below. Wage settlements for Corporate Exempt employees and employees belonging to IBEW and the Manitoba Hydro Professional Engineers Association are still to be determined.

Figure 6.15 – Contracted Wage Settlements

Effective Date	AMHSSE	CE	CUPE	IBEW	MHPEA	UNIFOR*
January 1, 2014	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
January 1, 2015	2.75%	2.75%	2.75%	2.75%	2.75%	2.75%
January 1, 2016	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
January 1, 2017	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%
January 1, 2018	1.00%	TBD	1.00%	2.00%	TBD	1.00%
January 1, 2019	1.25%	TBD	1.25%	TBD	TBD	1.25%
January 1, 2020	1.50%	TBD	1.50%	TBD	TBD	1.50%

** UNIFOR contracted wage settlements are effective the beginning of each pay period preceeding January 1st.*

In addition to contracted wage settlements, employees are also entitled to receive either merit based on performance or salary progression through the pay schedules assigned to job classifications. Merit and progression historically has resulted in an overall wage increase of 1 to 2% annually. For a detailed discussion on the corporations cost reduction plan, please refer to Tab 3 of this application.

The following sections provide an update on the cost containment strategies previously implemented to limit growth in O&A costs to 1%.

Reduction of Operational Positions

As part of its cost containment strategy, Manitoba Hydro committed to a reduction of 330 operational positions through the three year period of 2014/15 to 2016/17 and a commitment to hold non-labour costs below inflation, where possible. The corporation has leveraged its attrition by analyzing work processes and functions to identify opportunities for elimination, consolidation or technology enhancements. This has resulted in staff reductions and efficiencies of over 400 positions to date.

Figure 6.16 Position Reductions

	Committed Reductions				Achieved Reductions			
	2014/15	2015/16	2016/17	Total	2014/15	2015/16	2016/17	Total
President & CEO	2.0	-	-	2.0	2.0	1.0	1.0	4.0
General Counsel & Corporate Secretary	1.0	1.0	1.0	3.0	2.0	-	-	2.0
Human Resources & Corporate Services	33.0	27.0	21.0	81.0	53.0	23.0	1.0	77.0
Indigenous Relations	3.0	3.0	1.0	7.0	8.0	2.0	-	10.0
Finance & Strategy	4.0	3.0	3.0	10.0	6.0	6.0	1.0	13.0
Generation & Wholesale	10.0	12.0	6.0	28.0	42.0	50.0	13.0	105.0
Transmission	30.0	18.0	42.0	90.0	49.0	65.0	1.0	115.0
Marketing & Customer Service	62.0	27.0	20.0	109.0	70.0	21.0	12.0	103.0
Total	**146.0**	**91.0**	**94.0**	**330.0**	**232.0**	**168.0**	**29.0**	**429.0**

Supply Chain Management Initiatives

The corporation is continuing to undertake a number of supply chain management initiatives intended to realize savings on goods and services purchased, reduce or avoid operating costs, reduce working capital and reduce capital expenditures. These initiatives began in 2014/15 and have accumulated realized savings to date totaling approximately $8 million. These initiatives have included savings related to air travel, administrative expenses, maintenance and upgrade costs.

Year-over-Year Comparison

The following sections highlight the year over year changes in O&A from 2014/15 through 2018/19:

2015/16 Actual vs. 2014/15 Actual

The slight increase (less than 1%) in 2015/16 O&A is primarily attributable to reduced capitalization of overhead costs, an increase to bad debt expense and higher software license and maintenance contract expenditures. These increases have been partially offset by lower benefit costs as a result of changes in the discount rate as well as the impact of various cost containment initiatives.

2016/17 Outlook vs. 2015/16 Actual

The decrease in 2016/17 O&A is primarily attributable to the redeployment of staff from operations & maintenance to capital construction as well as a reduction in operations & maintenance EFTs and an overall focus on cost containment. These decreases were partially offset by higher wages and salaries due to general wage increases, merit and progression associated with previously negotiated labour contracts.

2017/18 Forecast vs. 2016/17 Outlook

The forecast decrease in 2017/18 O&A is primarily due to a significant reduction in the number of operations & maintenance EFTs as well as sourcing savings resulting from the Supply Chain Management initiative. This is partially offset by the impacts of the IBEW general wage increase and merit and progression, where applicable.

2018/19 Forecast vs. 2017/18 Forecast

The forecast decrease in 2018/19 O&A is primarily due to the full year impact of the reduction in the number of operations & maintenance EFTs as well as sourcing savings resulting from the Supply Chain Management initiative. This is partially offset by the impacts of the negotiated general wage increases and merit and progression, where applicable.

REFERENCE:

PUB/MH I-15 (a-b)

PREAMBLE TO IR (IF ANY):

Manitoba Hydro is requesting approval rates to recover in part revenue requirement including $518.3 million in OM&A costs in 2017/18 and $501.2 million in 2018/19, yet no detail in support of the balance by Corporate Group or Cost Element has been provided due to proposed reorganization considerations.

QUESTION:

Please provide detail on how Manitoba Hydro determined the change in OM&A from $535.8 million in 2016/17 to that forecast for the two test years.

RATIONALE FOR QUESTION:

RESPONSE:

The process undertaken to determine the change in O&A from the 2016/17 outlook projection of $535.8 million to the 2017/18 forecast of $518.3 and the 2018/19 forecast of $501.2 was described in response to Coalition/MH I-110.

The O&A target for 2017/18 was based on the year-end projection for 2016/17 actual results, adjusted for known wage settlements (IBEW) and the assumptions associated with senior management reductions and the voluntary departure program. The forecast assumed a reduction of approximately 500 EFTs at the corporate average salary plus benefits. Savings were assumed for a partial year as staff were anticipated to leave throughout the year. In addition, savings of approximately $6 million for supply chain initiatives for the 2017/18 fiscal year was incorporated. O&A savings from both workforce reductions and supply chain were assumed allocated 96% to electric operations and 4% to gas operations.

The O&A target for 2018/19 was based on the preliminary 2017/18 forecast adjusted for known wage settlements (IBEW) and a partial year of operating costs for Bipole III following in-service. The forecast was then reduced by the full year impact of the anticipated 500 EFT reduction. In addition, savings of a further $6 million for supply chain initiatives for the 2018/19 fiscal year was incorporated. O&A savings from both workforce reductions and supply chain were assumed allocated 96% to electric operations and 4% to gas operations.

REFERENCE:

PUB MFR 40

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update and file the response incorporating 2016 /17 actual.

RATIONALE FOR QUESTION:

RESPONSE:

The following table included in PUB MFR 40 (Revised) has been updated with 2016/17 actual information.

MANITOBA HYDRO
COSTS CAPITALIZED BY OPERATING/CORPORATE GROUP
(000's)

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual
President & CEO	$ -	$ -	$ -	$ -
General Counsel & Corporate Secretary	1 299	661	235	153
Human Resources & Corporate Services	14 876	17 146	18 302	18 174
Indigenous Relations	6 559	6 291	5 835	6 320
Finance & Strategy	940	554	305	372
Generation & Wholesale	62 976	63 108	64 462	66 644
Transmission	81 246	99 324	102 920	116 723
Marketing & Customer Service	98 118	103 815	113 099	119 603
	$ 266 013	**$ 290 899**	**$ 305 157**	**$ 327 988**

REFERENCE:

PUB/MH I-16

PREAMBLE TO IR (IF ANY):

QUESTION:

Please extend the table to cover the 20-year period through 2036. If detail is not available, please indicate the assumed level of capitalized order activities and capitalized overhead in each of the years used in the forecast.

RATIONALE FOR QUESTION:

RESPONSE:

Electric O&A targets are established considering the current business environment, known contract wage settlements, accounting changes, and operating costs associated with major new generation and transmission plant coming into service. Targets are not based on a detailed cost element breakdown including capital activity and overhead. COALITION/MH I-110 outlines the process undertaken to determine the O&A targets incorporated in the forecast for 2017/18 and 2018/19. For the years 2019/20 and beyond, adjustments to target have been made for escalation and the impacts of major new plant coming into service (Bipole and Keeyask).

REFERENCE:

PUB MFR 35

PREAMBLE TO IR (IF ANY):

QUESTION:

Please refile the response utilizing MH 16 Update and incorporating the known voluntary departure take-up - please include 2016/17 actual and forecast for 2017/18, 2018/19 and 2019/20.

RATIONALE FOR QUESTION:

RESPONSE:

Table 1 provided in PUB MFR 35 has been updated below to reflect 2016/17 actual information. The forecast for operating & administrative expenses was unchanged in MH16 Update.

Detailed O&A information (EFT, wages & salaries, overtime and benefits capitalized, etc.) for 2017/18, 2018/19 and 2019/20 is unavailable as the process of restructuring and reorganization following the voluntary departure initiative continues.

MANITOBA HYDRO
CAPITALIZED WAGES & SALARIES, OVERTIME, EMPLOYEE BENEFITS
(in thousands of $)

	2014/15 **Actual**	**2015/16** **Actual**	**2016/17** **Actual**	**2016/17** **IFF15 *** **Forecast**
Total O&A, before Capitalization	$922 689	$926 724	$950 636	$959 116
Domestic Revenue **	$1 424 515	$1 398 765	$1 418 778	$1 421 114
Wages, Salaries, Overtime & Benefits Capitalized	255 685	270 035	306 338	297 125
Wages, Salaries, Overtime & Benefits Charged to Operations	474 057	464 121	449 154	482 525
Total Wages & Salaries, Overtime & Benefits	$729 741	$734 156	$755 492	$779 650
Percentage Calculations:				
Percentage of Total Wages & Salaries, Overtime & Benefits				
Capitalized - Wages & Salaries, Overtime & Benefits	35%	37%	41%	38%
Charged to Operations - Wages & Salaries, Overtime & Benefits	65%	63%	59%	62%
	100%	100%	100%	100%
Percentage of Total O&A				
Capitalized - Wages & Salaries, Overtime & Benefits	28%	29%	32%	31%
Charged to Operations - Wages & Salaries, Overtime & Benefits	51%	50%	47%	50%
Wages & Salaries, Overtime & Benefits as Percentage of Total O&A (before capitalization)	79%	79%	78%	81%
Wages & Salaries, Overtime & Benefits Charged to Operations Percentage of Domestic Revenue	33%	33%	32%	34%

* Detailed budget information by department and cost element (i.e. wages & salaries, overtime, etc.) reflecting the overall IFF16 outlook projection is not readily available. As such, calculation of 2016/17 O&A components were based on the detailed forecasts prepared in IFF15.

** Domestic revenue forecast for 2016/17 reflects 2016/17 Outlook in IFF16.

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PUB MFR 33

Operating Expenses

Details on all cost containment actions to reduce the growth in OM&A over the last five fiscal years and forecast through the test years. [Attachment 33, 2016/17 Interim Application]

For information on cost containment actions to reduce future growth in O&A in the forecast years, please refer to Section 3.2 of Tab 3 of this Application.

For information on cost containment actions to reduce growth in O&A over the last five years, please refer to Section 6.2.5 of Tab 6 of this Application, as well as the following:

- Operating Expenses MFR 2 from the 2016/17 Supplemental Filing (Attachment 33) which can be found at the link provided below: https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/supplemental_filing_2015/35_attachment_33_operating_expenses_mfr_2.pdf
- Section 5.14 of Tab 5 from Manitoba Hydro's 2014/15 & 2015/16 General Rate Application which can be found at the link below: https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/pdf/tab_5.pdf

Operating Expenses MFR 2

Details on all cost containment actions to reduce the growth in OM&A forecast through the test years

Manitoba Hydro continues to undertake a number of initiatives intended to result in both operating and capital cost savings in order to maintain the proposed and indicative rate increases at 3.95%. These initiatives support the Corporation's commitment to manage its Operating & Administrative (O&A) expenditures to below inflationary levels and support Manitoba Hydro's debt management strategy by reducing capital investment resulting in lower overall debt and depreciation requirements.

A description of the various initiatives is provided in Tab 5, Section 5.14 of Manitoba Hydro's 2015/16 & 2016/17 General Rate Application; however updates to some of the key ongoing initiatives are outlined below:

Reduction of Operational Positions

As described in Section 6.0 of the Supplemental Filing, Manitoba Hydro has committed to a reduction of 330 operational positions over the 3 year period from 2014/15 to 2016/17. As of September 30, 2015 Manitoba Hydro has achieved a cumulative reduction of 315 operational positions. These reductions have been achieved through attrition, the application of technology and the consolidation and elimination of work processes where appropriate.

Asset Management Strategies

In order to effectively manage capital and operating costs associated with its sustaining capital investment requirements, Manitoba Hydro remains active in a number of asset management strategies as outlined below, in order to prolong the economic life of its assets and replace assets in poor health in the most cost-effective manner.

The Corporation is extending its implementation of its capital planning investment software (Copperleaf C55) into other capital intensive business units including Transmission, Customer Service & Distribution and Human Resources & Corporate Services. As well, a multi-year implementation of the Enterprise Asset Management system is underway which optimizes asset maintenance and refurbishment work activities for generation, HVDC, protection and communication assets.

To support the allocation of capital funds that maximize value to Manitoba Hydro as a whole, a Corporate Value Framework is also being developed, with the assistance of Copperleaf, in order to enhance the evaluation of investments across all lines of business in a consistent manner.

Manitoba Hydro continues to engage Kinetrics Inc. with respect to quantitatively establishing asset condition assessments of its transmission and distribution assets including refinements of health indices and recommended replacement schedules. In addition, reviews of equipment-based and strategic-based asset management practices are being undertaken to improve existing programs and advance new innovative approaches.

Supply Chain Management Initiatives

The Corporation has undertaken a number of supply change management initiatives intended to realize savings on goods and services purchased, reduce or avoid operating costs and reduce capital expenditures. This initiative began in 2014/15 and has continued throughout 2015/16 with particular focus on reducing excess inventory, implementing automatic replenishment, transitioning to strategic sourcing methods and optimizing staff levels with respect to Haulage Services.

Continuing into 2016/17, future objectives of the supply chain initiative include implementing stronger category management practices for procurement, optimizing material distribution networks, improving governance for the inventory of critical spares, improving forecasting and planning for inventory management, optimizing vehicle fleet levels and improving the repair, maintenance and fuel supply networks for fleet vehicles.

Technology Modernization

A multi-year distribution system modernization program is being developed consisting of numerous initiatives targeted at gaining efficiencies in distribution information management, basic performance monitoring, event-based grid management and outage management.

Manitoba Hydro’s distribution assets are aging and customer demand for electricity continues to strain the existing networks. This program is

> targeted at minimizing field operating costs due to an anticipated increase in outages, and prioritizing investments to areas where electric demand is the most urgent and where the condition of assets are in the poorest health. The expected outcome of the modernization program is that the Corporation will be in a better position to maintain or improve system reliability, manage localized capacity constraints and operate the distribution system more safely and efficiently.

As evidenced in Attachment 8 of the 2016/17 Supplemental Filing, Manitoba Hydro is tracking to achieve the annual O&A target of $541.7 million (target of $541.7 has remain unchanged between IFF14 and IFF15). To the end of September 2015, total O&A expenditures are $261.4 million which is $5.5 million lower than the forecast of $266.9 million. The under expenditure reflects the impacts of ongoing cost saving measures including reductions in operational positions.

5.14 COST SAVING INTIATIVES

Manitoba Hydro continues to undertake a number of initiatives that are intended to result in both operating and capital cost savings, ultimately improving financial results and easing pressures on rates. These initiatives support the Corporation's commitment to manage its OM&A expenditures below inflationary levels and support Manitoba Hydro's debt management strategy by reducing capital investment resulting in lower overall debt & depreciation requirements.

OM&A cost increases have been limited to 1% per year up to 2021/22 (excluding accounting changes and the increases associated with new major generation and transmission projects coming into service). After 2021/22, OM&A is projected to rise at the same level as inflation, despite the increasing cost pressures facing the Corporation from investments required for infrastructure renewal and increased capacity.

The following describes some of the key ongoing initiatives being undertaken by the corporation to manage its overall operating and capital expenditures.

5.14.1 Reduction of Operational Positions

Over the forecast period (2014/15 through 2016/17), Manitoba Hydro has committed to a reduction of approximately 300 operational positions and a commitment to hold non-labor costs below inflation, where possible. Manitoba Hydro intends to leverage its current attrition rate of approximately 300 staff per year by analyzing work processes and functions to identify opportunities for elimination, consolidation or technology enhancements that will result in staff reductions and efficiencies while still maintaining service levels. The reductions will vary across the corporation and are dependent upon the review of the many varied processes and functions unique to each area.

5.14.2 Consolidation of Rural District Offices

This initiative entails the closure of 24 rural district offices and their consolidation into the existing 20 Customer Service Centres. This effort is expected to enhance customer service through improved field crew deployment from the recently implemented Mobile Workforce Management System, improve system reliability by increasing distribution maintenance efforts and economize on customer-based administrative tasks.

Consolidation of the rural district offices is expected to yield a reduction in operating costs of approximately $2 million per year and result in the avoidance of future facility upgrade expenditures of $50 million and potential sales revenue of vacated properties. The first stage of facilities closures began in January 2014. The timing of this initiative is a result of declining district office traffic, increased customer demand for on-line services and increased customer requests at the previously established customer service centre hubs. This initiative is expected to maintain or improve outage response times.

Opportunities are also being derived in the centralizing of administrative work processes at Customer Service Centres. Amalgamating district staff into the larger Customer Service Centres has enabled Manitoba Hydro to create a more specialized and flexible workforce that is better equipped to respond to service disruptions. The Corporation also continues to monitor service levels and explore opportunities to optimize customer service, particularly in the areas of self-service and web-based outage information.

5.14.3 Managing Contractor Costs in Various Projects

The management of costs for capital projects involves proactively managing the schedule, scope and risks to the project. Manitoba Hydro has put in place industry standard project controls such as frequent schedule and cost monitoring with a focus on understanding the past and current costs. Manitoba Hydro is implementing a number of strategies throughout the lifecycle of major projects such as Bipole III and Keeyask.

For the procurement process, Manitoba Hydro has generally been following a multi-stage process where proponents are initially prequalified on their ability to complete the construction work, with pre-qualified proponents then competing largely on price to maximize competitiveness of the process and determine the successful proponent. In some instances, the work is awarded as a fixed price and pre-qualified proponents have input into finalization of contractual terms during the proposal phase, which balances risk between Manitoba Hydro and the proponents and reduces the overall uncertainty in the bids. The result was that proponents were able to reduce the amount of risk dollars carried in their bids, reducing overall bid price. In some instances, Manitoba Hydro informed all proponents that commercial and technical alternatives that may offer cost savings while still meeting the requirements of the contract would be considered resulting in noticeable cost savings.

5.14.4 Review of the Gillam Redevelopment and Expansion Project (GREP)

Manitoba Hydro undertook a review of the Gillam Redevelopment and Expansion Project (GREP) which involved assessing changing business requirements and developing a strategy that reflected these changes while applying the most current northern community design practices.

The revised community development plan incorporated a number of modifications including: eliminating expansion of infrastructure while strengthening community through enhanced centralized amenities, eliminating further expansion of new retail/commercial space, cancelling construction of a new 75 single detached unit housing subdivision substantially reducing the number of additional residential sub-divisions and new housing units, limiting/eliminating expansion of the existing trailer court sub-division, and cancelling construction of a new Wellness Centre.

In place of these developments, Manitoba Hydro's current plan is to expand mid-density housing within existing infrastructure, and upgrade and enhance recreation and leisure facilities in the Town Centre. The result of this assessment and strategy is a community plan with amenities intended to attract and retain Manitoba Hydro staff in Gillam and a cost savings of approximately $100 million.

5.14.5 Pointe du Bois Operations Spillway Cost Efficiencies

The Pointe du Bois Spillway Project was initiated to update the original spillway in order to meet current dam safety guidelines. The new spillway was placed into service in August 2014. River control has been a continuous challenge for Pointe du Bois Operations over the years due to constant river fluctuation.

The requirement to melt ice off the gates was a manual and very labour intensive process, requiring a crew of almost nine staff to operate the boilers. In addition, the original spillway was not designed to handle the pressure of shifting or expanding ice, and term employees were required to monitor ice thickness and cut trenches in front of the spillway structure.

As a result of the spillway replacement, Manitoba Hydro will see a reduction in OM&A costs. The in-service of the new spillway will result in an immediate and permanent reduction of approximately 1 EFT. In addition, the requirement for utility staff to be on call at all times has been eliminated with the ability to remotely control the river. Finally, the new spillway eliminates the need for boiler operation for melting ice and as a result the 9 positions held by Power Engineers have been deemed redundant.

It is estimated the Pointe du Bois spillway replacement will result in approximately $1 million in cost savings. In addition, the Pointe du Bois spillway structure replacement has resulted in a safer working environment for employees, through the ability to remote control operation.

5.14.6 Implementation of Mobile Workforce Management

Manitoba Hydro has implemented a new mobile workforce management system to effectively manage field activities for both the electric and natural gas businesses. This technology permits the planning, scheduling and dispatching of work orders in an optimized manner to derive cost efficiencies and timely service to customers. Rather than organizing work using geographic specific paper systems, field labour crews are now managed through a scheduling/dispatch centre with the ability to deploy field crews to emergency and urgent customer requests at the same time as improving the throughput of pre-scheduled maintenance work.

Work assignments are now sent to field laptop units electronically where activity details are entered in real time as the work progresses. Customer information and maintenance history are also readily available to field crews and electronic drawings can be retrieved within the vehicle. These field units are also equipped with GPS systems to identify the work locations of all crews.

The benefits of this initiative to customers include an improved ability to schedule appointments with shorter wait times and in precise time slots, improved timeliness of work flow, and the ability to track work orders. The system is also intended to result in faster response times in the event of emergencies. The implementation of mobile workforce management continues to permit the reduction of positions. To date 16 administrative positions have been eliminated and approximately four more positions each year for the next two years are identified for reduction. Field crew productivity savings are also expected due to reduced travel time and standardized matching of skills to job tasks, as well as the ability to complete greater volumes of maintenance work without increasing internal staffing requirements.

Adherence to stringent maintenance schedules is one way to prolong the life of Manitoba Hydro's aging and deteriorating distribution assets. Mobile workforce management has allowed Manitoba Hydro to meet its prescribed facility maintenance requirements, which in turn has helped to modestly relieve some pressure on advancing capital funding to replace distribution assets and also maintain existing levels of electric service reliability.

5.14.7 Asset Management Strategies

Manitoba Hydro is facing cost pressures associated with an aging electric infrastructure. In an ongoing effort to reduce expenditures, the Corporation has been undertaking a number of strategies to reduce overall costs on the electric system equipment while properly managing risk. The following initiatives have been implemented to continually improve the Corporation's asset management strategies.

Further optimization of maintenance programs based on equipment condition, performance and reliability assessments has been completed. A more detailed understanding of the overall condition of major system equipment groups has allowed Manitoba Hydro to strategically increase maintenance intervals on some equipment in relatively good condition. Manitoba Hydro will continue to monitor the overall condition of its major system equipment to ensure that the correct balance between maintenance and equipment replacement costs and reliability is achieved.

Enhanced condition assessments and economic analysis have been implemented to better determine the economic end of life of equipment or equipment groups. This strategy is expected to reduce life cycle costs as well as reduce overall system maintenance costs by undertaking equipment replacements at the optimum time considering cost and risk. A number of programs have been established for some asset types to fund replacements where condition assessments and economic analysis justify proactive replacements.

Various software systems that support asset management processes have been enhanced or replaced with more effective solutions. For example, the Corporation is presently implementing an integrated Enterprise Asset Management system that supports asset management processes at the corporate level, starting initially with the generation, HVDC, protection and communication assets. These types of systems will assist in minimizing equipment failures and also avoid decreases in system availability by ensuring all work is completed in an optimal fashion, and information is recorded to support asset management analysis processes. The Corporation has also implemented reporting enhancements for operating performance and equipment condition analysis, which further strengthens the capital planning process.

5.14.8 Technology Modernization Initiative for Better Capital Investment Decisions

Manitoba Hydro has been working with an external party to evaluate how it can advance its business activities through the use of smarter grid technologies. It is believed that investing today in smarter distribution equipment and information technology will provide economic benefit through enhanced capital improvements to Manitoba Hydro's distribution network over the decades to come.

The expected outcome of this detailed investigative partnership is that the Corporation will be in a far better position to maintain or improve system reliability, manage localized capacity constraints, operate more safely and efficiently, enhance customer service and better manage utility infrastructure with evolving customer load expectations. Other benefits that can be expected include a reduction in field operating costs when responding to outages and enhanced customer knowledge toward greater demand-side management efficiencies.

This investment in technology would allow the Corporation to gain a greater understanding of where capacity constraints and reliability issues specifically reside and prioritize its capital investments in areas that are both critically important and urgent.

5.14.9 Supply Change Management Initiatives

The Corporation is undertaking a number of supply change management initiatives intended to realize savings on goods and services purchased, reduce or avoid operating costs, reduce working capital, reduce capital expenditures on vehicle acquisitions, and reduce costs associated with fuel expenditures and external repairs and maintenance. A number of these initiatives started in 2014/15, while some are scheduled to begin in 2015/16 and 2016/17.

The supply chain management initiatives include implementing stronger category management (procurement) practices; improving inventory management processes; optimizing material distribution networks; improving governance for critical spares inventory; improving forecasting and planning for inventory management; optimizing Manitoba Hydro's vehicle fleet; and, improving the repair, maintenance and fuel supply network for fleet vehicles.

5.14.10 Records Centre Transition to Iron Mountain

Manitoba Hydro is contracting out to a third party service provider the processing and storing of the Corporation's physical records, which is currently managed by the Internal Records Centre. This initiative will deliver cost savings and improve service levels. A third party provider is able to provide a more secure environment for the Corporation's physical records.

As a result of the transition of the Records Centre to a third party provider, there will be a reduction of two EFTs, who are being redeployed to other areas of the Corporation to fill existing vacancies. In addition, this initiative will result in the availability of over 4,600 ft^2 of space to relocate work groups currently located outside of 820 Taylor Avenue. Moreover, service levels will improve with accessibility to physical records 24/7 rather than during Manitoba Hydro regular business hours.

5.14.11 Outage Management System

The implementation of Manitoba Hydro's outage management system is considered one of many steps toward modernizing the Corporation's distribution grid. Manitoba Hydro is continually undertaking efforts and implementing changes in its operations in order to leverage technology and continue to provide reliable customer service with improved labour productivity.

One of these initiatives includes the replacement of Manitoba Hydro's trouble call response system with an Outage Management System. The new system will improve Manitoba Hydro's ability to respond to and restore unplanned outages.

These cost containment measures have assisted the Corporation in maintaining projected annual rate increases at 3.95%, despite the Corporation facing significant and increasing cost pressures. This is consistent with the expectations of the PUB in Order 43/13, wherein it recommended that Manitoba Hydro control OM&A costs increases below inflation.

REFERENCE:

Tab 6 Page 24 Figure 6.16, PUB MFR 87, PUB/MH I-21(a)-(d) (2015 Interim Filing)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update the figure 6.16 in the same format as PUB/MH I-21 (a) (2015 Interim Filing) reflecting, Estimated Annual and Cumulative Savings by year. Please extend the table to include the new operational position reduction commitments for the years based on the take up from the voluntary departure program for 2017/18 and 2018/19.

b) Please provide an update to PUB/MH I-21(c) (2015 Interim Filing pages 3-4) for each the years 2013/14 through 2018/19 detailing the breakdown of EFTs based on capital construction, operations and maintenance and Governance Support Service.

c) Please provide an update to PUB MFR 87 based on the 2016/17 actual and the forecast for 2017/18 and 2018/19.

RATIONALE FOR QUESTION:

RESPONSE:

a) The table provided in Figure 6.16 provides an update on Manitoba Hydro's commitment over the three year period of 2014/15 to 2016/17 to a forecast reduction of 330 operational positions. The initiative was completed in February, 2017; as such the amounts provided in Figure 6.16 reflect the total achieved reductions for 2016/17. Detailed EFT information for 2017/18 and 2018/19 is unavailable as the process of restructuring and reorganization following the voluntary departure program continues. Figure 6.16 has been updated below to include Estimated Annual and Cumulative Savings, consistent with PUB/MH-I-21a of the 2016/17 Supplemental Filing.

O&A Cost Saving Measures
Position Reductions

	Committed Reductions				Achieved Reductions			
	2014/15	2015/16	2016/17	Total	2014/15	2015/16	2016/17	Total
President & CEO	2.0	-	-	2.0	2.0	1.0	1.0	4.0
General Counsel & Corporate Secretary	1.0	1.0	1.0	3.0	2.0	-	-	2.0
Human Resources & Corporate Services	33.0	27.0	21.0	81.0	53.0	23.0	1.0	77.0
Indigenous Relations	3.0	3.0	1.0	7.0	8.0	2.0	-	10.0
Finance & Strategy	4.0	3.0	3.0	10.0	6.0	6.0	1.0	13.0
Generation & Wholesale	10.0	12.0	6.0	28.0	42.0	50.0	13.0	105.0
Transmission	30.0	18.0	42.0	90.0	49.0	65.0	1.0	115.0
Marketing & Customer Service	62.0	27.0	20.0	109.0	70.0	21.0	12.0	103.0
Total	**146.0**	**91.0**	**94.0**	**330.0**	**232.0**	**168.0**	**29.0**	**429.0**

	Commitment Projections - Estimated Savings				Actual Reductions - Achieved Savings			
	2014/15	2015/16	2016/17	2017/18	2014/15	2015/16	2016/17	2017/18
	millions of $				*millions of $*			
Estimated Annual Savings	$ 7.3	$ 12.3	$ 10.0	$ 5.1	$ 11.6	$ 20.8	$ 10.7	
Estimated Cumulative Savings	7.3	19.3	29.7	35.8	11.6	31.9	43.2	

b) The following tables provide an update to PUB/MH I-21c of the 2016/17 Supplemental Filing for each of the years 2012/13 through 2016/17. Detailed EFT information for 2017/18 and 2018/19 is unavailable as the process of restructuring and reorganization following the voluntary departure program continues.

MANITOBA HYDRO
Straight time EFTs by Corporate / Operating Group

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual
Capital Construction	-	-	-	-
Operations & Maintenance	-	-	-	-
Governance, Support & Services	14	15	14	14
President & CEO	**14**	**15**	**14**	**14**
Capital Construction	9	4	2	1
Operations & Maintenance	1	1	2	2
Governance, Support & Services	17	20	23	23
General Counsel & Corporate Secretary	**27**	**25**	**27**	**26**
Capital Construction	126	151	143	135
Operations & Maintenance	77	80	80	95
Governance, Support & Services	620	574	569	550
Human Resources & Corporate Services	**823**	**805**	**792**	**780**
Capital Construction	55	53	47	50
Operations & Maintenance	7	7	5	5
Governance, Support & Services	37	39	37	31
Indigenous Relations	**99**	**99**	**89**	**86**
Capital Construction	8	4	2	3
Operations & Maintenance	37	42	35	36
Governance, Support & Services	131	125	129	124
Finance & Strategy	**176**	**171**	**166**	**163**
Capital Construction	482	453	438	443
Operations & Maintenance	807	736	693	686
Governance, Support & Services	181	145	155	139
Generation & Wholesale	**1 470**	**1 334**	**1 286**	**1 268**
Capital Construction	592	701	696	762
Operations & Maintenance	723	752	760	688
Governance, Support & Services	260	216	207	215
Transmission	**1 575**	**1 669**	**1 663**	**1 665**
Capital Construction	787	800	883	908
Operations & Maintenance	1 079	1 082	1 000	1 001
Governance, Support & Services	324	287	306	296
Marketing & Customer Service	**2 190**	**2 169**	**2 189**	**2 205**
Capital Construction	2 059	2 166	2 211	2 302
Operations & Maintenance	2 731	2 700	2 575	2 513
Governance, Support & Services	1 584	1 421	1 440	1 392
Total Corporation	**6 374**	**6 287**	**6 226**	**6 207**

*Note: A portion of Support & Governance EFTs are capitalized through overhead

c) Please see the response to part a).

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REFERENCE:

Tab 2 Page 6

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how Manitoba Hydro will maintain current service levels or discuss services that MH will no longer be able to offer, and what activities it will no longer be able to perform, as a result of the staffing reductions.

RATIONALE FOR QUESTION:

RESPONSE:

Manitoba Hydro has taken aggressive cost reduction action in order to mitigate to the greatest extent possible the burden on its ratepayers to contribute to the restoration of the financial health of the Corporation.

Manitoba Hydro has embarked on a broad restructuring of the organization and has undertaken the bulk of its cost efficiency program via a Voluntary Departure Program ("VDP"). Executing a headcount reduction of the scale Manitoba Hydro has initiated is an unprecedented challenge for the corporation.

Through this restructuring and with the departure of several hundred employees, Manitoba Hydro is addressing the prioritization of activities and the streamlining of work processes and reporting responsibilities throughout the organization. These preparations will not be fully tested until 2018 when the majority of identified departing employees actually leave the corporation and the process of restructuring is complete.

Manitoba Hydro acknowledges that with fewer resources and employees the risk of deterioration in service levels, reliability or satisfaction metrics increases; however, the corporation believes it can mitigate such impacts.

REFERENCE:

Tab 2 Page 6

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide rationale for the targeted of 15% reduction in headcount and how the Corporation deemed this an appropriate target in order to maintain the desired level and quality of services.

c) Please provide the accounting issues paper or similar document for the rationale surrounding the accounting treatment of the restructuring costs under IAS 37, including supporting calculations of the estimated total costs of restructuring

RATIONALE FOR QUESTION:

RESPONSE:

b) The overall reduction of 15% of the workforce was based on Manitoba Hydro's current expectation of the minimum staffing levels required to maintain reasonable levels of service and manage the operations of the corporation. The assessment also considered an analysis of the demographics of the workforce and their eligibility for retirement; as of September 2017, approximately 1000 staff would be eligible to retire. The workforce reduction program is a significant component of the financial plan to restore the financial strength of the corporation.

c) No formal accounting issues paper or similar document exists supporting the accounting treatment of the restructuring costs. IAS 37 *Provisions, Contingent Assets and Contingent Liabilities*, provides guidance on when and how to account for provisions such as restructuring liabilities. This guidance provides that a provision be recorded when "(a) an entity has a present obligation as a result of a past event; (b) it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation; and (c) a reliable estimate can be made of the amount of the obligation (paragraph 14)."

Manitoba Hydro has publicly announced the restructuring plan, employees have applied to the Voluntary Departure Program (VDP) and management has determined which employees have been accepted into that plan; therefore, as per IAS 37, Manitoba Hydro has a present obligation that can reliably be estimated.

In addition to the requirements of IAS 37, IAS 19 *Employee Benefits* requires that termination benefits resulting from either an entity's decision to terminate employment or an employee's decision to accept an entity's offer of benefits in exchange for termination of employment shall be recognized as a period expense. As per paragraph 165 of IAS 19, *"An entity shall recognise a liability and expense for termination benefits…"*.

The restructuring obligation recorded, based on detailed base salary data, was $41 million. In addition, incremental costs associated with the restructuring initiative have been forecasted, including a benefit allocation for employees who opt to take the VDP as a leave instead of a lump sum payment external consulting, legal expenses, as well as overtime incurred by staff to support the VDP initiative. The total estimated cost of restructuring to be expensed is approximately $50 million.

REFERENCE:

PUB/MH II - 6 PUB/MH I-11 (a-b); PUB/MH I-12; Coalition/MH I-153 (a)

PREAMBLE TO IR (IF ANY):

MH has reported the employee take up of the Voluntary Departure Package. Manitoba Hydro has also indicated that there is an assumed reduction of 100 capital EFTs.

QUESTION:

a) Please provide a full listing of the number of EFTs and related salary and benefits by the existing Operating Groups (prior to any proposed reorganization) related to the known take-up of the Voluntary Departure Package.

b) Please file the same information (EFTs and related salary and benefits) based on whether the individuals were in Capital Construction, Operations & Maintenance or Governance and Support prior to any proposed reorganization considerations.

RATIONALE FOR QUESTION:

RESPONSE:

a) The table below provides information by Corporate/Operating group reflecting the organization structure as of April, 2017 related to employees (not EFTs) leaving the corporation through the Voluntary Departure Program including the number of employees departing, their current annual salary and a benefit provision. In addition, four Manitoba Hydro employees seconded to subsidiary operations will be leaving the corporation as part of the Voluntary Departure Program with a current annual salary and benefits totaling $0.6 million.

VOLUNTARY DEPARTURE PROGRAM

($ in millions)

	Headcount	Salary	Benefits	Total
President & CEO	1	$ 0.1	$ 0.0	$ 0.1
General Counsel & Corporate Secretary	5	0.6	0.2	0.8
Human Resources & Corporate Services	147	12.3	4.3	16.6
Indigenous Relations	9	0.7	0.2	0.9
Finance & Strategy	33	3.0	1.1	4.1
Generation & Wholesale	157	13.9	4.9	18.8
Transmission	198	16.7	5.8	22.5
Marketing & Customer Service	267	20.8	7.3	28.1
Total	817	68.1	23.8	91.9

b) The categorization between capital construction, operations & maintenance or governance and support is an EFT classification calculated based upon the overall work deployment at the department level as captured through the time allocation process. Manitoba Hydro employees may be deployed to work on one or many functions related to capital, operations, maintenance and/or governance and support functions throughout the year.

An EFT is a stasticial calculation representing the equivalent of an employee working full-time hours of 73.7 hours bi-weekly or 1,921 hours per year.

As the VDP figures represent headcount reductions, Manitoba Hydro cannot provide the EFT category breakdown (capital, operating, governance, etc.).

REFERENCE:

PUB/MH I-17a

PREAMBLE TO IR (IF ANY):

QUESTION:

Please elaborate on what areas the Corporation has identified a risk in the deterioration of service levels, reliability or satisfaction metrics. Please discuss the mitigation measures the Corporation has identified to mitigate impacts.

RATIONALE FOR QUESTION:

RESPONSE:

The restructuring program underway is a significant undertaking. Manitoba Hydro has designed its go forward plans to maintain operations without slippage on any key metric. Management believes it has plans in place to re-allocate work processes to absorb over 800 employees (approximately 13% of total headcount) leaving the Corporation between June 1, 2017 and February 1, 2018 without any material deterioration in service levels, reliability or other metrics.

REFERENCE:

PUB/MH I-9 (a); PUB/MH I-17 (b)

PREAMBLE TO IR (IF ANY):

it is not clear when the restructuring will be completed. Detailed EFT information for 2017/18, 2018/19 and 2019/20 is unavailable as the process of restructuring and reorganization following the voluntary departure initiative continues.

QUESTION:

a) Please indicate who the Corporation has engaged to assist in change management activities related to the current restructuring of the organization.

b) Please indicate to what extent the cost incurred to date and budgeted to completion for this exercise.

c) Please file a copy of the work plan including milestones for the completion of the restructuring exercise.

d) Please file copies of any contracts, engagement letters or other documentation in support of the change management activities undertaken on behalf of the corporation.

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) to d):

The corporation has not engaged an external party to assist with change management activities related to the current restructuring of the organization. Change management is a key responsibility of management, with the overall tone, direction and expectations set by the President & CEO. In addition, management is utilizing internal staff with change management skillset and experience in various activities.

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PUB MFR 34
Operating Expenses

EFT staffing level information for the last five fiscal years and that forecast through the test years by business unit. [Attachment 34, 2016/17 Interim Application]

The following tables provide staffing levels under the current organization structure from 2011/12 through 2016/17 by Corporate and Operating Group (previously Business Unit).

As discussed in Tab 3, the Corporation is undertaking a major cost reduction program that includes a Voluntary Departure Program involving the departure of several hundred employees between June 1, 2017 and January 31, 2018. At the time of preparation of this response, it is not known as to the level of employee departures and subsequent employee reallocations within and between Corporate and Operating Groups.

As such, detailed EFT information for 2017/18 and 2018/19 by Corporate and Operating Group is unavailable.

Table 1 below provides a summary of combined straight time and overtime EFTs for the Corporation.

Table 1

MANITOBA HYDRO
TOTAL EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**
						IFF15 *
(Straight Time & Overtime Combined)	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**
President & CEO	19	18	14	15	14	14
General Counsel & Corporate Secretary	23	24	28	25	27	27
Human Resources & Corporate Services	840	835	839	821	810	839
Indigenous Relations	97	96	101	100	91	92
Finance & Strategy	174	175	177	172	166	166
Generation & Wholesale	1 533	1 573	1 622	1 479	1 417	1 481
Transmission	1 646	1 664	1 702	1 825	1 804	1 916
Marketing & Customer Service	2 276	2 293	2 273	2 276	2 281	2 295
Total	**6 608**	**6 678**	**6 756**	**6 713**	**6 610**	**6 830**

* *Detailed budget information by department and cost element (i.e. wages & salaries) as well as EFT information reflecting the overall IFF16 outlook projection is not readily available. As such, calculation of 2016/17 EFTs are based on the detailed forecasts prepared in IFF15.*

Table 2 below provides a summary of straight time EFTs by Corporate and Operating Group.

Table 2

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17 IFF15 *
	Actual	Actual	Actual	Actual	Actual	Forecast
President & CEO	19	18	14	15	14	14
General Counsel & Corporate Secretary	23	24	27	25	27	27
Human Resources & Corporate Services	826	820	823	805	792	816
Indigenous Relations	94	94	99	99	89	90
Finance & Strategy	174	174	176	171	166	165
Generation & Wholesale	1 391	1 433	1 470	1 334	1 286	1 327
Transmission	1 528	1 548	1 575	1 669	1 663	1 728
Marketing & Customer Service	2 195	2 185	2 190	2 169	2 189	2 197
Total	**6 250**	**6 296**	**6 374**	**6 287**	**6 226**	**6 364**

* *Detailed budget information by department and cost element (i.e. wages & salaries) as well as EFT information reflecting the overall IFF16 outlook projection is not readily available. As such, calculation of 2016/17 EFTs are based on the detailed forecasts prepared in IFF15.*

Table 3 below provides a summary of overtime EFTs by Corporate and Operating Group.

Table 3

MANITOBA HYDRO
OVERTIME EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 IFF15 * Forecast
General Counsel & Corporate Secretary	-	-	1	-	-	-
Human Resources & Corporate Services	14	15	17	16	18	23
Indigenous Relations	3	2	2	2	2	2
Finance & Strategy	-	-	-	-	1	-
Generation & Wholesale	143	140	152	145	131	154
Transmission	118	116	127	156	140	188
Marketing & Customer Service	80	109	83	107	92	98
Total	**358**	**382**	**382**	**426**	**384**	**466**

* *Detailed budget information by department and cost element (i.e. wages & salaries) as well as EFT information reflecting the overall IFF16 outlook projection is not readily available. As such, calculation of 2016/17 EFTs are based on the detailed forecasts prepared in IFF15.*

REFERENCE:

PUB MFR 34 – Operating Expenses, Page 2 of 4.

PREAMBLE TO IR (IF ANY):

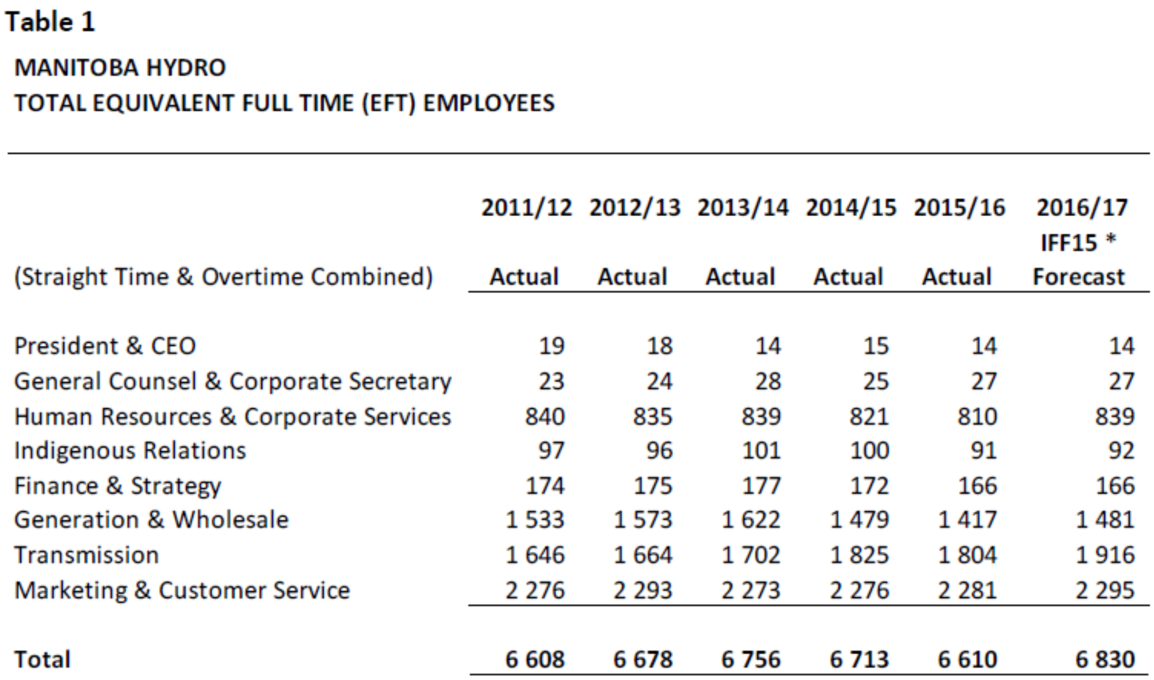

Table 1

MANITOBA HYDRO
TOTAL EQUIVALENT FULL TIME (EFT) EMPLOYEES

(Straight Time & Overtime Combined)	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 IFF15 * Forecast
President & CEO	19	18	14	15	14	14
General Counsel & Corporate Secretary	23	24	28	25	27	27
Human Resources & Corporate Services	840	835	839	821	810	839
Indigenous Relations	97	96	101	100	91	92
Finance & Strategy	174	175	177	172	166	166
Generation & Wholesale	1 533	1 573	1 622	1 479	1 417	1 481
Transmission	1 646	1 664	1 702	1 825	1 804	1 916
Marketing & Customer Service	2 276	2 293	2 273	2 276	2 281	2 295
Total	**6 608**	**6 678**	**6 756**	**6 713**	**6 610**	**6 830**

QUESTION:

a) Please explain how changing levels of expenditure in capital and OpEx programs were correlated to EFT levels over the historical period.

b) Why does Human Resources and Corporate Services account for over 12% of Manitoba Hydro's total EFT count?

RATIONALE FOR QUESTION:

RESPONSE:

a) The tables below reflect EFTs working on capital investment projects (capital construction) as well as EFTs supporting the operational programs of the corporation (operations & maintenance and governance, support and services) over the last 5 fiscal years. As shown, capital construction EFTs are the only area of growth during this period which correlates to the increased capital funding requirements to meet the electricity needs in the Province of Manitoba as well as firm sale commitments outside the province. The reduction in operational EFTs during the same period reflects Manitoba Hydro's commitment to manage its costs to levels below inflation.

MANITOBA HYDRO
TOTAL EQUIVALENT FULL TIME (EFT) EMPLOYEES

(Straight Time & Overtime Combined)	**2012/13** Actual	**2013/14** Actual	**2014/15** Actual	**2015/16** Actual	**2016/17** Actual
Capital Construction	2,082	2,204	2,345	2,384	2,497
Operations & Maintenance	2,942	2,906	2,888	2,729	2,656
Governance, Support & Services*	1,654	1,646	1,479	1,497	1,446
Total Corporation	**6,678**	**6,756**	**6,713**	**6,610**	**6,599**

	Straight Time EFTs			**Overtime EFTs**		
	2012/13 Actual	**2016/17 Actual**	**Increase/ (Decrease)**	**2012/13 Actual**	**2016/17 Actual**	**Increase/ (Decrease)**
Capital Construction	1,944	2,302	358	138	195	57
Operations & Maintenance	2,763	2,513	(250)	179	143	(36)
Governance, Support & Services*	1,589	1,392	(197)	65	54	(11)
Total	**6,296**	**6,207**	**(89)**	**382**	**392**	**10**

*Note: A portion of Governance, Support & Services EFTs are capitalized through overhead

b) Many of the support functions that the Corporation relies on for its day to day operations have been centralized within Human Resources & Corporate Services, including information technology, corporate facilities, purchasing, fleet services, etc.

As shown in the table below, this organizational group has seen an overall 5% reduction in EFT's while providing the same support functions across the corporation.

MANITOBA HYDRO
Straight time EFTs by Corporate / Operating Group

	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	5 Year Change	% Change
Capital Construction	123	126	151	143	135	12	10%
Operations & Maintenance	76	77	80	80	95	19	25%
Governance, Support & Services	621	620	574	569	550	(71)	-11%
Human Resources & Corporate Services	**820**	**823**	**805**	**792**	**780**	**(40)**	**-5%**

MIPUG MFR 8
Operating Expenses

Please provide definition and calculations supporting the EFT calculation and vacancy rate utilized. If different than the 2015/16 GRA (MIPUG/MH-I-6c) please explain.

The definitions and calculations supporting the EFT calculation and vacancy rate utilized for the 2017/18 & 2018/19 General Rate Application remain unchanged from those utilized at the time of the 2014/15 & 2015/16 General Rate Application.

An EFT represents the equivalent of an employee working full-time hours of 73.7 hours bi-weekly or 1,921 hours per year.

The vacancy rate is defined as the number of vacant positions as a percentage of the total positions. Vacant positions are attributable to a number of factors including employee retirements, turnover of staff both internally and externally and cost containment initiatives. As a result, these factors are not quantified individually in the vacancy rate calculation.

The actual vacancy rate for 2014/15 and 2015/16 and the forecast vacancy rate for 2016/17 are shown below. Actual vacancy rate results for 2016/17 are not yet available.

Fiscal Year	Vacancy Rate
2014/15	6.7%
2015/16	7.9%
2016/17 forecast	5.6%

REFERENCE:

MIPUG MFR 8 Staffing Levels

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an update of the table incorporating 2016/17 vacancy allowance and the assumed vacancy allowance for 2017/18 and 2018/19

b) Pleased add a column to the table in (a) of the assumed vacant positions on an EFT basis.

RATIONALE FOR QUESTION:

RESPONSE:

Response to part a) and b):

The table provided in MIPUG MFR 8 has been updated below to include the actual 2016/17 vacancy rate. In addition, a column has been added to include the calculated vacant EFTs for each of the fiscal years provided.

A vacancy allowance is unavailable for the forecast years 2017/18 and 2018/19 as the process of restructuring and reorganization continues; the full impact at an EFT level within the Corporation is still unknown.

Fiscal Year	Vacancy Rate	Vacant EFTs
2014/15	6.7%	454
2015/16	7.9%	530
2016/17	7.9%	532

ELECTRIC GENERAL RATE APPLICATION 2015

Manitoba Hydro Undertaking #43

Manitoba Hydro to provide an analysis of capital construction EFTs and what projects they are charging to in terms of major new generation or transmission projects for all Business Units.

Response:

Please see the table below for a summary by Business Unit of the straight time capital construction EFTs categorized as Sustaining Capital, Major New Generation & Transmission, Mitigation and DSM.

Capital Construction EFTs

	Actuals							
	2012/13				2013/14			
	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM
President & CEO	2	0	0	0	1	0	0	0
General Counsel & Corporate Secretary	1	4	0	0	1	8	0	0
Human Resources & Corporate Services	94	15	0	1	88	25	0	2
Corporate Relations	0	16	23	0	1	17	20	0
Finance & Regulatory	0	1	0	1	2	5	0	1
Generation Operations	141	117	3	0	161	130	2	0
Major Capital Projects	1	184	0	0	0	201	0	0
Transmission	352	215	0	0	386	202	1	0
Customer Service & Distribution	653	27	0	0	683	24	0	0
Customer Care & Energy Conservation	8	0	8	75	12	0	9	76
Total Corporation	1252	579	34	76	1335	612	32	78

*EFTs are rounded

Capital Construction EFTs

	Forecast											
	2014/15				2015/16				2016/17			
	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM
President & CEO	0	0	0	0	0	0	0	0	0	0	0	0
General Counsel & Corporate Secretary	1	5	0	0	1	5	0	0	1	5	0	0
Human Resources & Corporate Services	109	34	0	1	103	32	0	1	103	32	0	1
Corporate Relations	1	18	23	0	1	18	23	0	1	19	23	0
Finance & Regulatory	1	2	0	0	0	1	0	0	0	1	0	0
Generation Operations	169	116	5	0	164	113	5	0	166	114	5	0
Major Capital Projects	1	229	0	0	1	294	0	0	1	295	0	0
Transmission	403	241	0	0	431	258	0	0	431	258	0	0
Customer Service & Distribution	702	23	0	0	739	24	0	0	745	24	0	0
Customer Care & Energy Conservation	12	2	9	83	15	3	11	102	15	3	11	102
Total Corporation	1399	671	38	85	1455	748	39	104	1463	751	40	104

*EFTs are rounded

68

REFERENCE:

MFR 32 & 42 OM&A Expense Analysis

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a similar analysis comparing 2016/17 actual with forecast.

RATIONALE FOR QUESTION:

RESPONSE:

Figures 1 to 4 compare the actual vs. forecast Operating and Administrative costs for the 2016/17 fiscal year by Operating and Corporate Group (previously Business Unit) and by cost element.

Differences over 5% and $500,000 have been explained.

Figure 1. Operating & Administrative Cost by Operating/Corporate Group

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY OPERATING/CORPORATE GROUP

(In thousands of $)	**2016/17 Actual**	**2016/17 Outlook**	**2016/17 Variance**	**%**	**Ref**
President & CEO	$ 4 944	$ 5 614	$ 670	12%	1
General Counsel & Corporate Secretary	3 994	4 264	270	6%	
Human Resources & Corporate Services	108 115	109 841	1 726	2%	
Indigenous Relations	5 518	6 884	1 366	20%	2
Finance & Strategy	29 374	30 064	690	2%	
Generation & Wholesale	147 503	151 369	3 865	3%	
Transmission	147 310	155 342	8 033	5%	3
Marketing & Customer Service	197 005	198 714	1 709	1%	
Subtotal	**643 763**	**662 092**	**18 329**	**3%**	
Corporate Allocations & Adjustments	(21 116)	(20 730)	383	-2%	
Operating & Administration Charged to Gas Operations	(65 384)	(67 818)	(2 434)	4%	
Capitalized Overhead	(21 438)	(21 873)	(435)	2%	
	$ 535 826	**$ 551 670**	**$ 15 844**	**3%**	
Year End Outlook Adjustment		(16 280)			
O&A Costs Attributable to Electric Operations	**$ 535 826**	**$ 535 390**	**$ (436)**	**0%**	

Figure 2. Operating & Administrative Cost by Operating/Corporate Group with Variance Explanations

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY OPERATING/CORPORATE GROUP
2016/17

Ref	**Business Unit**	**Fav (Unfav)**	**Explanation**
1	President & CEO	670	Primarily due to a lower requirement for consulting services and lower corporate donations than anticipated.
2	Indigenous Relations	1,366	Mainly due to lower wages, salaries and associated benefits as a result of vacancies. In addition, a greater focus on capital projects such as Keeyask and capital programs such as Shoreline Protection and Waterways Management resulting in lower O&A costs.
3	Transmission	8,033	Primarily due to lower employee related costs as a result of vacancies throughout the operating group.

Figure 3. Operating & Administrative Cost by Cost Element

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2016/17 Actual	2016/17 Outlook	2016/17 Variance	%	Ref
Employee Related Expenditures					
Wages & salaries	$ 517 311	$ 532 941	$ 15 630	3%	
Overtime	72 256	76 975	4 719	6%	1
Employee benefits	165 924	169 734	3 810	2%	
Other	71 943	75 141	3 198	4%	
Total Employee Related Expenditures	827 435	854 792	27 357	3%	
Less: Capitalized labour & overhead	(349 426)	(359 223)	(9 797)	3%	
Operational Employee Related Expenditures	478 009	495 569	17 560	4%	
External services and materials	125 601	128 760	3 159	2%	
Donations, sponsorships & grants	2 134	2 367	233	10%	
Uncollectible accounts	4 266	4 218	(48)	-1%	
Other	6 905	3 853	(3 052)	-79%	2
Cost recoveries	(15 706)	(15 278)	426	-3%	
O&A charged to gas operations	(65 384)	(67 818)	(2 434)	4%	
	$ 535 826	**$ 551 670**	**$ 15 844**	**3%**	
Year End Outlook Adjustment		(16 280)			
Operating & Administrative Expenses	**$ 535 826**	**$ 535 390**	**$ (436)**	**0%**	

Figure 4. Operating & Administrative Cost by Cost Element with Variance Explanations

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
2016/17

Ref	Cost Element	Fav (Unfav)	Explanation
1	Overtime	4 719	Lower overtime costs primarily due to vacancies in the Bipole III project and at the Dorsey and Radisson/Henday converter stations, lower overall requirements for the Enterprise Asset Management (EAM) project, as well as the suspension of the Pointe Du Bois Unit & Accessories and Safety Upgrade projects. This was partly offset by overtime associated with storm restoration work. It is noted that overtime variances relating to capital projects will be offset in the overtime component of capitalized labor.
2	Other	(3 052)	Mainly due to costs associated with the expensing of projects previously recorded in CWIP as the projects are no longer providing future economic benefit.

REFERENCE:

Tab 6 Figure 6.14 OM&A by Cost Element

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a comparison of the Forecast to Actual OM&A costs by cost element for 2016/17 in the same level of detail of MH's Quarterly filings and explain material variances.

b) Please provide an updated Figure 6.14 the detail of OM&A by cost element including details of external services and materials supporting the forecast for 2017/18 through 2018/19.

RATIONALE FOR QUESTION:

RESPONSE:

a) The tables below provide a comparison of the forecast to actual O&A costs by cost element for 2016/17. Differences over 5% and $500,000 have been explained.

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

	2016/17 Actual	2016/17 Outlook	2016/17 Variance	%	Ref
Employee related expenditures					
Wages & salaries	$ 517,311	$ 532,941	$ 15,630	2.9	
Overtime	72,256	76,975	4,719	6.1	1
Employee benefits	165,924	169,734	3,810	2.2	
Employee safety & training	4,181	5,474	1,294	23.6	2
Travel expenses	28,854	31,294	2,440	7.8	3
Motor vehicle	30,133	29,522	(611)	(2.1)	
Office expenses	8,776	8,851	75	0.8	
Other	71,943	75,141	3,198		
Total employee related expenditures	827,435	854,792	27,357		
Less: capitalized labor & overhead	(349,426)	(359,223)	(9,797)	(2.7)	
Operational employee related expenditures	478,009	495,569	17,560		
Materials & tools	24,967	26,368	1,401	5.3	4
Consulting & professional fees	15,840	15,954	114	0.7	
Construction & maintenance services	16,821	17,214	393	2.3	
Building & property services	29,039	28,416	(623)	(2.2)	
Equipment maintenance & rentals	18,734	18,826	92	0.5	
Consumer services	5,236	5,268	33	0.6	
Customer & public relations	2,227	2,827	600	21.2	5
Sponsored memberships	1,677	1,674	(3)	(0.2)	
Computer services	967	1,093	126	11.5	
Communication systems	1,668	2,037	369	18.1	
Research & development costs	2,355	2,471	116	4.7	
Administrative services	6,071	6,611	541	8.2	6
External services and materials	125,601	128,760	3,159		
Donations, sponsorships & grants	2,134	2,367	233	9.9	
Uncollectible accounts	4,266	4,218	(48)	(1.1)	
Miscellaneous expense	6,905	3,715	(3,190)	(85.9)	7
Contingency planning	-	138	138	100.0	
Other	6,905	3,853	(3,052)		
Corporate recoveries	(831)	(537)	294	54.8	
Operating expense recovery	(14,875)	(14,742)	133	0.9	
Cost recoveries	(15,706)	(15,278)	427		
O&A charged to gas operations	(65,384)	(67,818)	(2,434)	(3.6)	
	$ 535,826	$ 551,670	$ 15,844	2.9	
Year end outlook adjustment		(16,280)			
Operating & Administrative Expenses	$ 535,826	$ 535,390	$ (435)	(0.1)	

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT WITH VARIANCE EXPLANATIONS
2016/17

Ref	Cost Element	Fav (Unfav)	Explanation
1	Overtime	4 719	Lower overtime costs primarily due to vacancies in the Bipole III project and at the Dorsey and Radisson/Henday converter stations, lower overall requirements for the Enterprise Asset Management (EAM) project, as well as the suspension of the Pointe Du Bois Unit & Accessories and Safety Upgrade projects. This was partly offset by overtime associated with storm restoration work. It is noted that overtime variances relating to capital projects will be offset in the overtime component of capitalized labor.
2	Employee Safety & Training	1 294	Mainly due to lower external training costs as a result of cost containment measures and lower requirement for safety clothing.
3	Travel Expenses	2 440	Primarily due to cost containment measures, more employees working within their headquarter zone as well as vacancies.
4	Materials & Tools	1 401	Mainly due to a lower material requirement for maintenance work at various generating stations as well as at Radisson and Dorsev converter stations.
5	Customer & Public Relations	600	Mainly due to lower spending on the Manitoba Hydro brand marketing campaign due to cost containment
6	Administrative Services	541	Mainly due to lower postage costs, deferral of Power Smart marketing services as well as lower electronic service costs for the Click Before you Dig program.
7	Miscellaneous Expense	(3 190)	Mainly due to costs associated with the expensing of projects previously recorded in CWIP as the projects are no longer providing future economic benefit.

b) Detailed O&A information for 2017/18 and 2018/19 is unavailable as the process of restructuring and reorganization following the voluntary departure initiative continues.

REFERENCE:

PUB/MH I-14

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has provided quarterly reporting for 2016/17 of OM&A expenditures by Cost Element for the first three quarters of the year. The answer appears to be prepared on a different basis than that previously provided, including different account groupings that do not allow for comparison.

QUESTION:

a) Please provide the detail of OM&A on a consistent basis as previously provided in the quarterly reports, including breaking out the detail of capital Order Activities and capitalized overhead and other employee expenses

b) Please provide a comparison of the OM&A by cost element from PUB/MH I-73(b) (2014/15 & 2015/16 GRA) with that provided in PUB/MH I-14 prepared on the same basis as at the last GRA and explain the differences.

RATIONALE FOR QUESTION:

RESPONSE:

a) The following table provides O&A expenditures by cost element at the same level of detail as provided in the quarterly reports for 2016/17 with additional sub-totals.

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

	2016/17 Actual	2016/17 Outlook	2016/17 Variance	%
Employee related expenditures				
Wages & salaries	$ 517,311	$ 532,941	$ 15,630	2.9
Overtime	72,256	76,975	4,719	6.1
Employee benefits	165,924	169,734	3,810	2.2
Employee safety & training	4,181	5,474	1,294	23.6
Travel expenses	28,854	31,294	2,440	7.8
Motor vehicle	30,133	29,522	(611)	(2.1)
Office expenses	8,776	8,851	75	0.8
Other	71,943	75,141	3,198	
Total employee related expenditures	827,435	854,792	27,357	
Less:				
Capitalized labor	(327,988)	(337,350)	(9,362)	
Overhead	(21,438)	(21,873)	(435)	
Operational employee related expenditures	478,009	495,569	17,560	
Materials & tools	24,967	26,368	1,401	5.3
Consulting & professional fees	15,840	15,954	114	0.7
Construction & maintenance services	16,821	17,214	393	2.3
Building & property services	29,039	28,416	(623)	(2.2)
Equipment maintenance & rentals	18,734	18,826	92	0.5
Consumer services	5,236	5,268	33	0.6
Customer & public relations	2,227	2,827	600	21.2
Sponsored memberships	1,677	1,674	(3)	(0.2)
Computer services	967	1,093	126	11.5
Communication systems	1,668	2,037	369	18.1
Research & development costs	2,355	2,471	116	4.7
Administrative services	6,071	6,611	541	8.2
External services and materials	125,601	128,760	3,159	
Donations, sponsorships & grants	2,134	2,367	233	9.9
Uncollectible accounts	4,266	4,218	(48)	(1.1)
Miscellaneous expense	6,905	3,715	(3,190)	(85.9)
Contingency planning	-	138	138	100.0
Other	6,905	3,853	(3,052)	
Corporate recoveries	(831)	(537)	294	54.8
Operating expense recovery	(14,875)	(14,742)	133	0.9
Cost recoveries	(15,706)	(15,278)	427	
O&A charged to gas operations	(65,384)	(67,818)	(2,434)	(3.6)
	$ 535,826	$ 551,670	$ 15,844	2.9
Year end outlook adjustment		(16,280)		
Operating & Administrative Expenses	$ 535,826	$ 535,390	$ (435)	(0.1)

b) The table below provides 2016/17 O&A by cost element in a format consistent with PUB/MH I-73b) from the last GRA. Variance explanations for all differences over 5% and $500,000 were provided in PUB/MH I-14.

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

	2016/17 Actual	2016/17 Outlook	2016/17 Variance	%
Wages & Salaries	$ 517,311	$ 532,941	$ 15,630	2.9
Overtime	72,256	76,975	4,719	6.1
Employee Benefits	165,924	169,734	3,810	2.2
Sub-Total	755,492	779,650	24,159	3.1
Less: Labour & Benefits Charged to Capital	(291,260)	(300,129)	(8,869)	(3.0)
Labour & Benefits Charged to Operations	464,232	479,522	15,290	3.2
Other costs				
Employee Safety & Training	4,181	5,474	1,294	23.6
Travel Expenses	28,854	31,294	2,440	7.8
Motor Vehicle	30,133	29,522	(611)	(2.1)
Materials & Tools	24,967	26,368	1,401	5.3
Consulting & Professional Fees	15,840	15,954	114	0.7
Construction & Maintenance Services	16,821	17,214	393	2.3
Building & Property Services	29,039	28,416	(623)	(2.2)
Equipment Maintenance & Rentals	18,734	18,826	92	0.5
Consumer Services	5,236	5,268	33	0.6
Customer & Public Relations	2,227	2,827	600	21.2
Sponsored Memberships	1,677	1,674	(3)	(0.2)
Computer Services	967	1,093	126	11.5
Communication Systems	1,668	2,037	369	18.1
Research & Development Costs	2,355	2,471	116	4.7
Administrative Services	6,071	6,611	541	8.2
Office Expenses	8,776	8,851	75	0.8
Donations, Sponsorships & Grants	2,134	2,367	233	9.9
Uncollectible accounts	4,266	4,218	(48)	(1.1)
Miscellaneous Expense	6,905	3,715	(3,190)	(85.9)
Contingency Planning	-	138	138	100.0
Corporate Recoveries	(831)	(537)	294	54.8
Operating Expense Recovery	(14,875)	(14,742)	133	0.9
Sub-Total	195,143	199,061	3,918	2.0
Less: Other Costs Charged to Capital	(36,728)	(37,222)	(494)	(1.3)
Other Costs Charged to Operations	158,415	161,839	3,424	2.1
Total	**622,647**	**641,361**	**18,714**	**2.9**
Less:				
Capitalized Overhead	(21,438)	(21,873)	(435)	(2.0)
O&A charged to gas operations	(65,384)	(67,818)	(2,434)	(3.6)
	$ 535,826	$ 551,670	$ 15,845	2.9
Year End Outlook Adjustment		(16,280)		
Operating & Administrative Expenses	**$ 535,826**	**$ 535,390**	**$ (435)**	**(0.1)**

In preparing a response to this information request, Manitoba Hydro noted that the 2016/17 Actual and 2016/17 IFF15 Forecast amounts for "Wages, Salaries, Overtime & Benefits Capitalized" were incorrectly stated in PUB/MH I-12 as $306,338 for 2016/17 actual and $297,125 forecast, respectively. Please note that these values should reflect the same values as "Labour and Benefits Charged to Capital" in the table above namely $291,260 for 2016/17 actual and $300,129 for 2016/17 Outlook.

A revised response to PUB/MH I-12 has been filed.

PUB MFR 41
Operating Expenses

A comparison of the OM&A per customer (actual and forecast) with that presented at the previous GRA (IFF14) for comparable years for each year through the test years. [Appendix 11.29, 2015/16 GRA]

The following table provides a comparison of O&A cost per customer for 2014/15 through 2018/19 with that presented at the last GRA (IFF14).

Table 1. Operating & Administrative Costs Actual/MH16 vs MH14

	Actual			MH16 Forecast		
	CGAAP 2015 Actual	**IFRS 2015 Actual**	**IFRS 2016 Actual**	**IFRS 2017 Outlook**	**IFRS 2018 Forecast**	**IFRS 2019 Forecast**
O&A expense (millions of $)	480	538	543	535	518	501
# of Customers	561 869	561 869	567 634	570 601	576 469	582 352
O&A per customer (in dollars)	854	958	957	938	899	860

	MH14 Forecast					
	CGAAP 2015 Forecast	**CGAAP 2015 Forecast**	**IFRS 2016 Forecast**	**IFRS 2017 Forecast**	**IFRS 2018 Forecast**	**IFRS 2019 Forecast**
O&A expense (millions of $)	486	486	542	552	557	571
# of Customers	558 871	558 871	565 222	572 144	579 324	586 385
O&A per customer (in dollars)	870	870	959	965	961	974

	2015	**2015**	**2016**	**2017**	**2018**	**2019**
Difference in O&A per customer (in dollars)	(16)	88	(2)	(27)	(62)	(114)

The MH14 Forecast for 2015 was stated using CGAAP. Actual results under CGAAP reflect a decrease in O&A cost per customer as compared to forecast primarily due to an increase in the number of customers. Conversely, actual results for 2015 under IFRS reflect an increase in O&A cost per customer primarily due to costs previously charged to capital which are no longer eligible for capitalization and must be expensed.

The marginal decrease in 2016 O&A cost per customer is primarily due to a higher number of customers. The decrease in O&A forecast cost per customer for 2017, 2018 and 2019 in

MH16 is mainly due to an overall focus on cost containment including forecasted impacts of the corporate cost reduction initiative.

6.2.10 Other Expenses

Other expenses include costs associated with Power Smart programs designed to reduce overall energy consumption and assist customers in managing their energy costs, site restoration and regulatory costs as well as the provision of work on customer owned plant and other miscellaneous expenditures.

Upon transition to IFRS, additions to Power Smart programs, site restoration and regulatory costs are recorded initially in other expenses and are then removed through net movement to regulatory deferral accounts on the statement of financial position.

Figure 6.25 Other Expenses

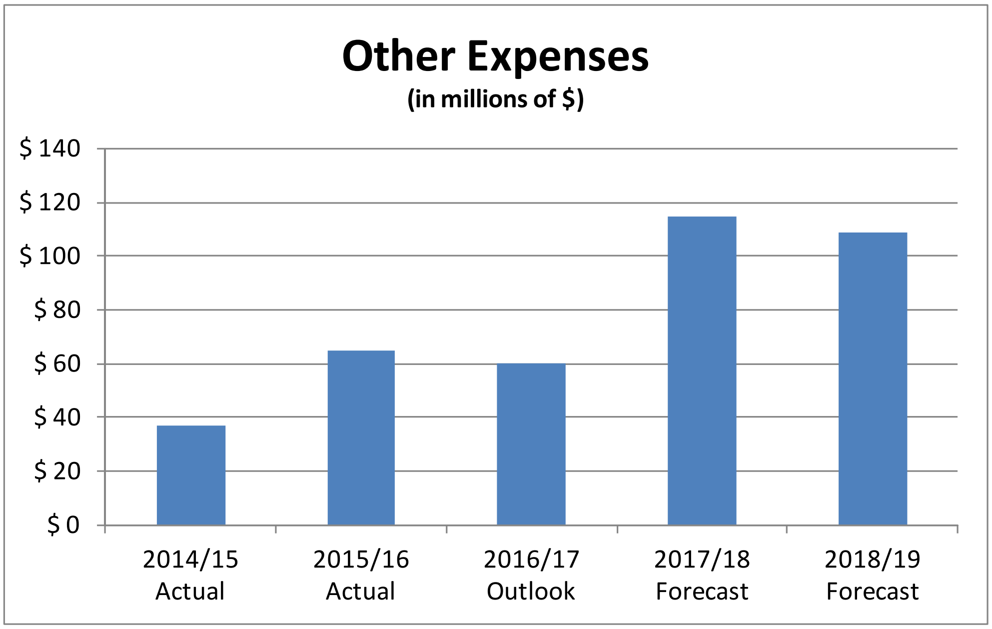

Figure 6.26 Other Expenses breakdown

MANITOBA HYDRO
OTHER EXPENSES
(000's)

	2014/15 Actual	**2015/16 Actual**	**2016/17 Outlook**	**2017/18 Forecast**	**2018/19 Forecast**
Power Smart expenses	$ 31 475	$ 53 816	$ 50 143	$ 55 678	$ 99 404
Site restoration	2 359	3 371	1 424	2 794	2 703
Regulatory costs	1 038	3 949	4 389	3 664	2 339
Cost of services provided to external entities	1 860	3 687	290	2 200	2 200
Consulting engagement	-	-	4 086	-	-
Corporate restructuring costs	-	-	-	50 388	2 193
Miscellaneous	313	116	132	132	132
Total other expenses *	$ 37 045	$ 64 939	$ 60 464	$ 114 856	$ 108 970
Year over year $ change		$ 27 894	$ (4 475)	$ 54 392	$ (5 886)
Year over year % change		75.3%	-6.9%	90.0%	-5.1%

** Amounts related to Power Smart programs, site restoration and regulatory costs have been deferred and are reflected in Net Movement*

The following sections highlight the year over year changes in other expenses from 2014/15 through 2018/19:

2015/16 Actual vs. 2014/15 Actual

The increase in 2015/16 other expenses is primarily due to an increase in investments in Power Smart programs related to the implementation of the LED Roadway Lighting Conversion program and the Customer Sited Load Displacement program, as well as increased customer participation in the commercial lighting program.

2016/17 Outlook vs. 2015/16 Actual

The decrease in 2016/17 other expenses is due to a reduction in Power Smart investments related to the LED Roadway Lighting Conversion program resulting from delays in securing a qualified contractor to continue the work from the prior year. In addition, site remediation costs declined as projects were postponed and fewer business initiative opportunities transpired compared to 2015/16. These decreases are

REFERENCE:

Tab 6, Page 37
Appendix 3.1, Page 57
Tab 3, Page 8
2016/17 Supplemental Filing, Attachment 1, Page 41

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a version of MH15 (similar in detail to that in Attachment 1 referenced above) consistent with the values used in Figure 3.4.

c) Please identify any discrepancies in the MH15 values reported in Figure 3.4 and the response to part (b) with values reported in the MH15 forecast provided in the 2016/17 Supplemental Filing (Attachment 1) and reconcile the differences.

d) Are the MH15 and MH16 values used for Figure 3.4 determined on a comparable basis or are there differences due to difference in accounting treatment or the line item under which certain costs are reported. If there are differences, please indicate what they are.

e) With respect to MH16, please provide a schedule that identifies those costs that are reported as Other Expenses for the years 2016/17 through 2033/34 but are subsequently treated as additions to regulatory deferral accounts.

f) With the adjustments identified in part (e), is Other Expense as reported in MH16 is comparable to that reported in MH14. If not, what other adjustments are required?

RATIONALE FOR QUESTION:

To understand the differences between the various forecasts of Other Expense.

RESPONSE:

b) The following MH15 projected financial statement was restated to be consistent with the presentation in MH16 and used to support Figure 3.4.

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610	1 626	1 641
additional*	61	125	191	258	335	411	493	580	672	769	872
BPIII Reserve Account	(67)	(69)	(21)	87	87	87	-	-	-	-	-
Extraprovincial	406	449	474	548	825	966	979	983	986	884	903
Other	28	28	29	30	31	32	32	32	33	34	35
	1 985	2 086	2 225	2 465	2 844	3 066	3 087	3 191	3 301	3 313	3 450
EXPENSES											
Operating and Administrative	552	557	571	585	601	607	619	631	644	657	669
Finance Expense	601	598	747	863	1 110	1 209	1 195	1 197	1 196	1 180	1 175
Finance Income	(13)	(19)	(31)	(39)	(31)	(21)	(15)	(15)	(19)	(13)	(18)
Depreciation and Amortization	383	398	472	521	617	663	677	691	707	723	739
Water Rentals and Assessments	116	113	113	115	124	127	132	132	132	132	133
Fuel and Power Purchased	151	182	180	174	206	228	227	230	242	231	241
Capital and Other Taxes	122	136	145	146	149	157	157	163	165	166	167
Other Expenses	66	104	98	95	95	100	77	69	74	81	84
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 986	2 078	2 302	2 468	2 879	3 078	3 077	3 107	3 148	3 164	3 199
Net Income before Net Movement in Reg. Deferral	(1)	8	(77)	(3)	(35)	(12)	10	84	153	149	251
Net Movement in Regulatory Deferral	21	50	33	25	20	19	(11)	(22)	(21)	(19)	(17)
Net Income	20	59	(44)	21	(15)	7	(1)	62	131	130	234
Net Income Attributable to:											
Manitoba Hydro	**29**	**63**	**(41)**	**21**	**(13)**	**6**	**(4)**	**56**	**129**	**129**	**232**
Non-controlling Interest	(9)	(4)	(3)	(0)	(2)	1	3	5	3	1	2
* Additional Domestic Revenue											
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%
Financial Ratios											
Equity	14%	14%	13%	13%	13%	12%	12%	12%	13%	13%	14%
EBITDA Interest Coverage	1.52	1.52	1.46	1.54	1.57	1.62	1.63	1.70	1.78	1.81	1.92
Capital Coverage	0.98	1.21	1.05	1.06	1.13	1.32	1.49	1.59	1.60	1.61	1.78

c) The following schedule highlights the MH15 line items that were restated for the purposes of making direct comparisons in MH16 in Figure 3.4 in comparison with MH15 filed in the 2016/17 Supplemental Filing (Attachment 1).

	MH15 2017/18 & 2018/19 GRA Figure 3.4		MH15 2016/17 Supplemental Filing Attachment 1		Difference	
	2017-2019	2017-2027	2017-2019	2017-2027	2017-2019	2017-2027
REVENUES						
Domestic Revenue						
at approved rates	4 661	17 394	4 661	17 394	-	-
additional*	378	4 767	378	4 767	-	-
BPIII Reserve Account	(157)	103	(157)	(157)	-	260
Extraprovincial	1 329	8 402	1 329	8 402	-	-
Other	86	344	86	605	-	(260)
	6 296	31 011	6 296	31 011	-	-
EXPENSES						
Operating and Administrative	1 680	6 693	1 680	6 693	-	-
Finance Expense	1 946	11 070	1 883	10 837	63	233
Finance Income	(63)	(233)	-	-	(63)	(233)
Depreciation and Amortization	1 253	6 590	1 253	6 590	-	-
Water Rentals and Assessments	341	1 369	341	1 369	-	-
Fuel and Power Purchased	513	2 292	513	2 292	-	-
Capital and Other Taxes	402	1 671	402	1 671	-	-
Other Expenses	268	942	268	942	-	-
Corporate Allocation	25	90	25	90	-	-
	6 366	30 486	6 366	30 486	-	-
Net Income before Net Movement in Reg. Deferral	(70)	525	(70)	525	-	-
Net Movement in Regulatory Deferral	105	79	105	79	-	-
Net Income	35	604	35	604	-	-
Net Income Attributable to:						
Manitoba Hydro	**51**	**607**	**51**	**607**	**-**	**-**
Non-controlling Interest	(16)	(2)	(16)	(2)	-	-

d) The restatements of MH15 line items for comparison purposes in Figure 3.4 relate to:

- Reclassification of amortization of the Bipole III Deferral Account from Other Revenue to the BPIII Reserve; and,
- The presentation of Finance Income separately from Finance Expense in in accordance with IFRS.

e) The following schedule provides a breakdown of costs reported as Other Expenses in MH16 and the costs that are subsequently treated as additions to regulatory deferral accounts.

MH16 OTHER EXPENSES
in millions of dollars

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	ACTUAL																	
Other Expense Components:																		
Power Smart expenses	50.1	55.7	99.4	94.3	88.9	86.9	66.5	60.3	62.3	66.6	70.7	74.7	78.9	82.8	82.3	83.9	85.6	87.4
Site restoration	1.4	2.8	2.7	1.4	1.3	1.1	0.0	-	-	-	-	-	-	-	-	-	-	-
Regulatory costs	4.4	3.7	2.3	1.3	1.9	1.4	2.0	1.4	2.0	1.5	2.1	1.6	2.2	1.6	2.3	1.7	2.4	1.8
Conawapa Generation	-	-	-	379.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost of services provided to external entities	0.3	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9
Consulting engagement	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate restructuring costs	-	50.4	2.2	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MH16 Other Expenses	**60.5**	**114.9**	**109.0**	**481.3**	**94.5**	**91.9**	**71.0**	**64.3**	**67.0**	**70.7**	**75.5**	**79.0**	**83.9**	**87.3**	**87.4**	**88.5**	**91.0**	**92.2**
Transfers to Net Movement:																		
Power Smart expenses	(50.1)	(55.7)	(99.4)	(94.3)	(88.9)	(86.9)	(66.5)	(60.3)	(62.3)	(66.6)	(70.7)	(74.7)	(78.9)	(82.8)	(82.3)	(83.9)	(85.6)	(87.4)
Site restoration	(1.4)	(2.8)	(2.7)	(1.4)	(1.3)	(1.1)	(0.0)	-	-	-	-	-	-	-	-	-	-	-
Regulatory costs	(4.4)	(3.7)	(2.3)	(1.3)	(1.9)	(1.4)	(2.0)	(1.4)	(2.0)	(1.5)	(2.1)	(1.6)	(2.2)	(1.6)	(2.3)	(1.7)	(2.4)	(1.8)
Conawapa Generation	-	-	-	(379.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(56.0)	**(62.1)**	**(104.4)**	**(476.8)**	**(92.1)**	**(89.5)**	**(68.5)**	**(61.7)**	**(64.4)**	**(68.1)**	**(72.8)**	**(76.2)**	**(81.1)**	**(84.4)**	**(84.6)**	**(85.6)**	**(88.0)**	**(89.1)**
MH16 Other Expenses Restated	**4.5**	**52.7**	**4.5**	**4.6**	**2.4**	**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**

f) After removing the one-time consulting engagement costs and the corporate restructuring costs, the costs are comparable to MH14. Please see the schedule below.

MH16 OTHER EXPENSES
in millions of dollars

	2017 ACTUAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cost of services provided to external entities	0.3	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9
Consulting engagement	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate restructuring costs	-	50.4	2.2	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MH16 Other Expenses Restated From (e)	**4.5**	**52.7**	**4.5**	**4.6**	**2.4**	**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**
Adjustments:																		
Consulting engagement	(4.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate restructuring costs	-	(50.4)	(2.2)	(2.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(4.1)	**(50.4)**	**(2.2)**	**(2.2)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
MH16 Other Expenses Adjusted	**0.4**	**2.3**	**2.3**	**2.4**	**2.4**	**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**

MH14 OTHER EXPENSES
in millions of dollars

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cost of services provided to external entities	2.4	2.5	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.7	2.7
MH14 Other Expenses	**2.4**	**2.5**	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.3**	**2.4**	**2.4**	**2.5**	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**

PUB MFR 32

Operating Expenses

Schedule comparing the historical OM&A actual with IFF forecasts with explanations of variances for 2015/16 and 2016/17. [Attachment 32, 2016/17 Interim Application]

PUB MFR 42

Operating Expenses

A schedule which compares OM&A cost for the forecast years at the previous GRA to actual results presented in this application in both dollar change and percentage change by:

1. **Cost element**
2. **Business unit**

and explain any variances in excess of 5%. [Appendix 11/30, 2015/16 GRA]

Figures 1 to **4** compare the actual vs. forecast Operating and Administrative costs for the 2015/16 fiscal year to the forecast provided in the 2016/17 Interim Application (COALITION/MH I-24a-d) by Operating and Corporate Group (previously Business Unit) and by cost element. The 2016/17 actual information is not yet available.

Differences over 5% and $500,000 have been explained.

Figure 1. Operating & Administrative Cost by Operating/Corporate Group

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY OPERATING/CORPORATE GROUP

(In thousands of $)	**2015/16 Actual**	**2015/16 Forecast**	**2015/16 Variance**	**%**	**Ref**
President & CEO	$ 5 941	$ 6 478	$ 538	8%	1
General Counsel & Corporate Secretary	3 944	3 343	(601)	-18%	2
Human Resources & Corporate Services	107 404	109 369	1 966	2%	
Indigenous Relations	6 534	6 776	242	4%	
Finance & Strategy	30 296	30 405	109	0%	
Generation & Wholesale	146 286	153 449	7 163	5%	3
Transmission	152 144	155 225	3 081	2%	
Marketing & Customer Service	196 991	194 868	(2 124)	-1%	
Subtotal	**649 540**	**659 914**	**10 373**	**2%**	
Corporate Allocations & Adjustments	(23 217)	(26 941)	(3 724)	14%	4
Operating & Administration Charged to Gas Operations	(66 607)	(66 691)	(84)	0%	
Capitalized Overhead	(16 986)	(24 541)	(7 555)	31%	5
O&A Costs Attributable to Electric Operations	**$ 542 729**	**$ 541 740**	**$ (989)**	**0%**	

Figure 2. Operating & Administrative Cost by Operating/Corporate Group with Variance Explanations

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY OPERATING/CORPORATE GROUP
2015/16

Ref	Business Unit	Fav (Unfav)	Explanation
1	President & CEO	538	Primarily due to lower consulting engagements and fewer corporate sponsorships and memberships partly due to cost containment initiatives.
2	General Counsel & Corporate Secretary	(601)	Mainly due to less work than anticipated related to capital projects.
3	Generation & Wholesale	7,163	Mainly due to lower reactive maintenance requirements, less travel due to trainees working within their headquarter zone and lower overall costs as a result of vacancies.
4	Corporate Allocations & Adjustments	(3,724)	Primarily due to the continued expensing of meter testing and exchange activities as per existing regulatory practices partly offset by a higher recovery of costs from subsidiaries.
5	Capitalized Overhead	(7,555)	Mainly due to cost containment measures resulting in an overall reduction of overhead costs including items such as IT infrastructure and employee relocations costs.

Figure 3. Operating & Administrative Cost by Cost Element

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	**2015/16 Actual**	**2015/16 Forecast**	**2015/16 Variance**	**%**	**Ref**
Employee Related Expenditures					
Wages & salaries	$ 506 811	$ 525 103	$ 18 292	3%	
Overtime	67 982	71 099	3 117	4%	
Employee benefits	159 363	160 329	966	1%	
Other	70 832	75 948	5 116	7%	1
Total Employee Related Expenditures	804 988	832 479	27 491	3%	
Less: Capitalized labour & overhead	(317 387)	(343 058)	(25 671)	7%	2
Operational Employee Related Expenditures	487 601	489 421	1 820	0%	
External services and materials	128 062	125 864	(2 197)	-2%	
Donations, sponsorships & grants	2 592	3 249	657	20%	3
Uncollectible accounts	5 748	4 078	(1 671)	-41%	4
Other	1 123	(478)	(1 601)	335%	5
Cost recoveries	(15 789)	(13 703)	2 086	-15%	6
O&A charged to gas operations	(66 607)	(66 691)	(84)	0%	
Operating & Administrative Expenses	**$ 542 729**	**$ 541 740**	**$ (989)**	**0%**	

Figure 4. Operating & Administrative Cost by Cost Element with Variance Explanations

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
2015/16

Ref	Cost Element	Fav (Unfav)	Explanation
1	Other - Employee related expenditures	5 116	Mainly due to lower travel costs as a result of vacancies and work being done within employees' headquarter zones as well as lower than anticipated fuel costs.
2	Capitalized labour & overhead	(25 671)	Mainly due to vacancies across the corporation resulting in lower activities and associated overhead for various projects such as Bipole III and Keeyask. In addition, cost containment measures resulted in lower overall reduction of overhead costs including items such as IT infrastructure and employee relocations costs.
3	Donations, sponsorships & grants	657	Primarily due to lower than anticipated corporate sponsorships and memberships as a result of cost containment initiatives.
4	Uncollectible accounts	(1 671)	Due to a higher bad debt write-off of uncollectible accounts as a result of enhanced processes which enabled the corporation to address a backlog of accounts requiring review.
5	Other	(1 601)	Primarily related to expensing costs resulting from the cancellation of various capital projects.
6	Cost recoveries	2 086	Primarily due to higher recovery of costs from subsidiaries and costs associated with operational work performed at diesel sites partly offset by lower staffhouse recoveries as a result of lower occupancy levels.

REFERENCE:

MFR 39 Operating Expenses

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an update to table 2 including 2016/17 actual
b) Please extend the schedule with the forecasts for 2017/18, 2018/19.

RATIONALE FOR QUESTION:

RESPONSE

Response to a) and b):

Table 1 and Table 2 from PUB MFR 39 have been updated to include 2016/17 actual results and are provided below. Detailed information for 2017/18 and 2018/19 is unavailable as the process of restructuring and reorganization following the voluntary departure plan continues.

Table 1. Operating & Administrative Costs with Compound Annual Growth

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS
(000's)

	CGAAP			
	2011/12 Actual	2012/13 Actual	2013/14 Actual	2011/12-2013/14 Compound Annual Growth
O & A Costs Attributable to Electric Operations	$ 403 304	$ 462 952	$ 480 717	9.2

	IFRS*					
	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2014/15-2018/19 Compound Annual Growth
O & A Costs Attributable to Electric Operations	$ 538 404	$ 542 729	$ 535 826	$ 518 340	$ 501 183	(1.8)

*$20 million of O&A attributable to electric operations has been deferred and reflected in Net Movement in response to the directive in PUB Order 73/15.

Table 2. Operating & Administrative Costs by Division with Compound Annual Growth Rate

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY DIVISION
(000's)

	CGAAP				IFRS*			
	2011/12 Actual	**2012/13 Actual**	**2013/14 Actual**	**2011/12-2013/14 Compound Annual Growth**	**2014/15 Actual**	**2015/16 Actual**	**2016/17 Actual**	**2014/15-2016/17 Compound Annual Growth**
President & CEO								
Administration	$ 9 377	$ 7 478	$ 6 296	(18.1)	$ 6 825	$ 5 684	$ 4 944	(14.9)
	9 377	**7 478**	**6 296**	**(18.1)**	**6 825**	**5 684**	**4 944**	**(14.9)**
General Counsel & Corporate Secretary								
Law	$ 2 032	$ 1 961	$ 1 767	(6.7)	$ 1 837	$ 2 464	$ 2 663	20.4
General Counsel & Corp Secretary	537	1 742	2 859	130.8	3 070	1 480	1 330	(34.2)
	$ 2 568	**$ 3 703**	**$ 4 626**	**34.2**	**$ 4 906**	**$ 3 944**	**$ 3 994**	**(9.8)**
Human Resources & Corporate Services								
Information Technology Services	$ 36 543	$ 38 839	$ 41 879	7.1	$ 43 718	$ 43 199	$ 42 910	(0.9)
Human Resources	10 804	12 158	18 677	31.5	17 281	18 582	18 885	4.5
Workplace Safety & Health and Corp Serv	38 642	39 894	43 007	5.5	42 319	42 849	43 307	1.2
Corporate Environmental Management	1 710	1 849	1 789	2.3	1 658	1 515	1 585	(2.2)
VP Administration	2 405	2 258	1 225	(28.6)	1 036	1 515	1 428	17.4
	90 104	**94 997**	**106 577**	**8.8**	**106 012**	**107 660**	**108 115**	**1.0**
Indigenous Relations								
Indigenous Relations	$ 2 475	$ 3 372	$ 3 537	19.6	$ 3 103	$ 3 365	$ 3 338	3.7
Partnerships & Stakeholder Initiatives	1 200	1 692	3 513	71.1	3 750	2 409	1 521	(36.3)
VP Administration	664	749	846	12.8	966	759	659	(17.5)
	4 339	**5 813**	**7 896**	**34.9**	**7 820**	**6 534**	**5 518**	**(16.0)**
Finance & Strategy								
Treasury	$ 1 915	$ 1 978	$ 2 165	6.3	$ 2 208	$ 2 109	$ 1 992	(5.0)
Corporate Risk Mgmt Department	938	921	1 069	6.8	1 116	1 080	1 104	(0.5)
Rates & Regulatory Affairs	3 152	3 276	3 334	2.9	3 663	3 591	3 336	(4.6)
Corporate Controller	9 590	9 946	10 018	2.2	10 425	10 606	10 492	0.3
Internal Audit	1 449	1 378	1 702	8.4	1 588	1 922	1 829	7.3
Administration	8 029	9 629	8 317	1.8	9 449	10 988	10 620	6.0
	25 074	**27 129**	**26 607**	**3.0**	**28 449**	**30 296**	**29 374**	**1.6**

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY DIVISION
(000's)

	CGAAP				IFRS*			
	2011/12	**2012/13**	**2013/14**	**2011/12-2013/14 Compound**	**2014/15**	**2015/16**	**2016/17**	**2014/15-2016/17 Compound**
	Actual	**Actual**	**Actual**	**Annual Growth**	**Actual**	**Actual**	**Actual**	**Annual Growth**
Generation & Wholesale								
Power Planning	$ 7 372	$ 8 028	$ 8 284	6.0	$ 10 088	$ 11 471	$ 11 107	4.9
Generation North	28 621	32 371	36 476	12.9	35 735	34 479	34 951	(1.1)
Generation South	51 298	51 394	55 341	3.9	54 949	52 200	52 259	(2.5)
Keeyask Project	(107)	(38)	137	0.0	155	356	712	114.4
Engineering Services	7 715	15 591	16 167	44.8	16 096	15 570	17 532	4.4
Power Sales & Operations	13 364	13 408	14 646	4.7	13 952	15 567	16 161	7.6
Wuskwatim Project	30	293	34	5.3	1	-	-	(100.0)
Project Services Division	(103)	268	26	0.0	278	798	793	69.0
VP Administration	20 265	24 596	25 400	12.0	17 660	15 845	13 988	(11.0)
	128 455	**145 911**	**156 512**	**10.4**	**148 914**	**146 286**	**147 503**	**(0.5)**
Transmission								
HVDC	$ 24 698	$ 26 136	$ 28 642	7.7	$ 32 750	$ 33 352	$ 32 705	(0.1)
Bipole III Converter Stations	(41)	109	(10)	(50.6)	225	274	409	34.7
Transmission System Operations	29 857	35 875	37 839	12.6	36 876	38 283	38 790	2.6
Transmission Planning & Design	4 936	9 181	8 406	30.5	7 040	9 227	7 693	4.5
Transmission Construction & Line Mtce	15 998	20 084	21 191	15.1	20 801	21 480	20 095	(1.7)
Apparatus Maintenance	38 952	43 858	45 422	8.0	44 461	46 021	44 588	0.1
VP Administration	1 446	2 726	3 147	47.5	3 327	3 507	3 030	(4.6)
	115 845	**137 968**	**144 637**	**11.7**	**145 480**	**152 144**	**147 310**	**0.6**

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY DIVISION
(000's)

	CGAAP				IFRS*			
	2011/12 Actual	**2012/13 Actual**	**2013/14 Actual**	**2011/12-2013/14 Compound Annual Growth**	**2014/15 Actual**	**2015/16 Actual**	**2016/17 Actual**	**2014/15-2016/17 Compound Annual Growth**
Marketing & Customer Service								
Distribution Eng & Construction	$ 2 335	$ 12 264	$ 11 150	118.5	$ 14 981	$ 14 594	$ 14 420	(1.9)
Customer Service Operations - Wpg&North	49 287	51 114	50 109	0.8	52 503	49 633	49 897	(2.5)
Customer Service Operations - South	43 695	50 188	47 778	4.6	48 770	47 598	49 858	1.1
Business Support & Capital Asset Mgmt	15 747	16 876	20 601	14.4	21 806	22 801	23 775	4.4
Gas Supply	2 488	2 572	2 865	7.3	3 024	3 122	3 253	3.7
Industrial & Commercial Solutions	2 870	4 735	5 705	41.0	5 032	4 638	4 473	(5.7)
Consumer Marketing & Sales	11 630	13 107	14 263	10.7	13 840	13 858	13 509	(1.2)
Business Support Services	22 012	24 089	27 658	12.1	30 038	29 109	27 446	(4.4)
Public Affairs	2 196	1 996	1 750	(10.7)	1 594	4 668	4 857	74.6
Communication & Engagement	161	194	211	14.5	507	932	470	(3.7)
Creative Services	1 559	1 813	1 615	1.8	1 177	2 109	1 496	12.7
VP Administration	7 148	7 654	6 734	(2.9)	6 713	3 930	3 551	(27.3)
	161 128	**186 603**	**190 440**	**8.7**	**199 985**	**196 991**	**197 005**	**(0.7)**
Corporate Allocations & Adjustments	(18 384)	(13 196)	(21 617)	8.4	(16 601)	(23 217)	(21 115)	12.8
Operating & Administration Charged to Centra	(62 117)	(63 735)	(66 808)	3.7	(70 355)	(66 607)	(65 384)	(3.6)
Capitalized Overhead	(53 084)	(69 720)	(74 449)	18.4	(23 032)	(16 986)	(21 438)	(3.5)
	$ 403 304	**$ 462 952**	**$ 480 717**	**9.2**	**$ 538 404**	**$ 542 729**	**$ 535 826**	**(0.2)**

*$20 million of O&A attributable to electric operations has been deferred and reflected in Net Movement in response to the directive in PUB Order 73/15.

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PUB MFR 36

Operating Expenses

Schedule that shows average salary per EFT by business unit for the last five fiscal years through the test years including the compound annual growth rate for the last five historical years and the growth for each of the test years. [PUB/MH I-7, 2016/17 Interim Application]

Table 1 below reflects a compounded annual growth of 3.1% in average salary from 2011/12 to 2015/16 and an annual increase of 2.9% for 2016/17, stated in the current organization structure by Corporate and Operating group (previously Business Unit).

As discussed in Tab 3, the Corporation is undertaking a major cost reduction program that includes a Voluntary Departure Program involving the departure of several hundred employees between June 1, 2017 and January 31, 2018. At the time of preparation of this response, it is not known as to the level of employee departures and subsequent employee reallocations within and between Corporate and Operating Groups. As a result, average salary information for 2017/18 and 2018/19 by Corporate and Operating Group is unavailable.

Table 1 Average Salary per EFT

MANITOBA HYDRO
AVERAGE SALARY PER EFT BY OPERATING/CORPORATE GROUP

	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2011/12-2015/16 Compounded Annual Growth	2016/17 IFF15 * Forecast
President & CEO	$ 157 398	$ 175 645	$ 189 657	$ 212 588	$ 251 263	12.4	$ 242 942
General Counsel & Corporate Secretary	97 976	100 394	103 041	107 236	110 747	3.1	113 434
Human Resources & Corporate Services	75 465	76 895	76 789	78 981	81 642	2.0	82 562
Indigenous Relations	76 079	77 328	79 269	81 499	83 413	2.3	87 224
Finance & Strategy	81 748	83 447	85 397	89 463	93 995	3.6	95 838
Generation & Wholesale	73 177	75 233	76 792	82 169	86 022	4.1	88 593
Transmission	74 408	77 169	78 343	80 800	84 381	3.2	86 569
Marketing & Customer Service	65 426	67 059	67 987	70 440	72 449	2.6	75 186
Total	**71 689**	**73 723**	**74 791**	**77 944**	**80 917**	**3.1**	**83 257**

* *Detailed budget information by department and cost element (i.e. wages & salaries) as well as EFT information reflecting the overall IFF16 outlook projection is not readily available. As such, calculation of 2016/17 salaries per EFT are based on the detailed forecasts prepared in IFF15.*

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PUB MFR 44

Payments to Government

A schedule of actual and forecast payments made to the Province and Municipalities for five historical years and for the 20-year forecast period. [Appendix 11.32, 2015/16 GRA]

Please see the following schedule for all actual payments to municipalities and the Province for 2012 through 2016, and forecasted payments from 2017 through 2036.

Payments to the Province and Municipalities (Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Sinking Fund Admin. Fee	Capital Taxes	Payroll Taxes	Provincial Mitigation or Settlement Obligations (1)	Municipal GILT and Business Taxes	Gross Electricity Operations Revenue	Gross Export Revenue	Total Provincial Payments (GILT & Business Tax Not Included)	Provincial Payments as a Percentage of Gross Revenue
2012	111	82	0	52	10	1	21	1,572	333	256	16%
2013	110	90	0	55	11	1	21	1,740	329	267	15%
2014	118	96	0	60	11	0	23	1,879	402	285	15%
2015	117	105	0	62	12	0	25	1,889	384	296	16%
2016	117	118	0	69	12	1	25	1,905	415	317	17%
2017	122	132	0	79	12	5	27	1,915	468	351	18%
2018	115	153	0	93	13	0	26	2,022	454	374	18%
2019	103	185	0	105	13	0	27	2,240	432	406	18%
2020	104	210	0	113	13	0	28	2,436	455	440	18%
2021	105	226	0	119	14	0	28	2,713	578	463	17%
2022	108	234	0	122	14	0	29	2,998	696	478	16%
2023	118	231	0	130	14	0	29	3,154	795	493	16%
2024	118	232	0	130	14	0	30	3,236	818	494	15%
2025	115	229	0	129	14	0	30	3,325	844	488	15%
2026	116	225	0	128	15	0	31	3,250	707	483	15%
2027	116	217	0	128	15	0	31	3,321	714	475	14%
2028	116	211	0	127	15	0	32	3,378	708	469	14%
2029	115	209	0	127	15	0	32	3,458	721	467	13%
2030	115	206	0	127	16	0	33	3,551	733	465	13%
2031	115	190	0	127	16	0	34	3,647	744	448	12%
2032	115	184	0	127	16	0	34	3,756	745	442	12%
2033	115	175	0	128	17	0	35	3,869	743	433	11%
2034	114	166	0	128	17	0	35	3,987	739	425	11%
2035	114	160	0	128	17	0	36	4,106	732	420	10%
2036	114	155	0	133	17	0	37	4,161	654	420	10%

(1) Hydro entered into an agreement with the Province whereby the Corporation assumed obligations of the Province with respect to certain northern development projects. Obligations totaling $143 million were assumed, with respect to which water rental charges had been fixed until March 31, 2001. Of these obligations, $5 million remain to be paid in fiscal 2017 and future years.

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PUB MFR 45

Payments to Government

A schedule detailing the calculation of the net Debt Guarantee Fee for five historical years and through the twenty year forecast period. [Appendix 11.33, 2015/16 GRA]

Please see **Table 1** below for the calculation of the net Manitoba Hydro Provincial Debt Guarantee Fee (PGF) for 2010/11 through to 2035/36.

Table 1 Provincial Debt Guarantee Fee Calculation

Payments to Government MFR 2

MANITOBA HYDRO
Provincial Debt Guarantee Fee (PGF) Calculations
($ millions CAD)

	Actual 2011 (1)	Actual 2012 (1)	Actual 2013 (1)	Actual 2014 (1)	Actual 2015 (1)	Actual 2016 (1)	Actual 2017 (1)	Forecast 2018 (2)	Forecast 2019 (2)	Forecast 2020 (2)	Forecast 2021 (2)	Forecast 2022 (2)	Forecast 2023 (2)
Long Term Debt Balance	8,538	8,628	9,348	9,937	10,944	12,653	14,542	16,289	19,334	21,901	23,497	24,019	23,765
Short Term Debt Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
Trust Investment from Pre-Financing	(554)	(100)	-	-	(90)	(475)	(946)	(563)	(432)	(472)	(486)	(180)	(165)
PGF Assessed On	7,984	8,528	9,348	9,937	10,854	12,178	13,596	15,725	18,902	21,429	23,012	23,840	23,600
Guarantee Fee Rate	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %
Amount Paid to Province	80	85	93	99	109	122	136	157	189	214	230	238	236
Portion Allocated to Centra	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)	(4)	(4)	(5)	(5)
Net MB Hydro Provincial Debt Guarantee Fee	**77**	**82**	**90**	**96**	**105**	**118**	**132**	**153**	**185**	**210**	**226**	**234**	**231**

Notes: (1) The fee calculation is based on ending principal par value debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the debt guarantee fee on bonds issued for mitigation purposes. The long term debt balance presented in Payments to Government MFR 2 represents that amount of debt upon which the Provincial Debt Guarantee Fee was paid or is payable.

(2) US Dollar long term debt balance at March 31, 2017 was converted at forecast year end exchange rate of 1.30 for the assessment of the 2018 PGF.
US Dollar long term debt balances at March 31, 2018, 2019, 2020, 2021, 2022 were converted at forecast year end exchange rate of 1.28, 1.25, 1.21, 1.21, 1.18 respectively for the assessment of the PGF for years 2019 to 2023.
US Dollar long term debt balances at March 31, 2023 and beyond were converted at forecast year end exchange rate of 1.15 for the assessment of the PGF for years 2024 and beyond.

Table 1 Provincial Debt Guarantee Fee Calculation (continued)

Payments to Government MFR 2

MANITOBA HYDRO
Provincial Debt Guarantee Fee (PGF) Calculations
($ millions CAD)

	Forecast 2024 (2)	Forecast 2025 (2)	Forecast 2026 (2)	Forecast 2027 (2)	Forecast 2028 (2)	Forecast 2029 (2)	Forecast 2030 (2)	Forecast 2031 (2)	Forecast 2032 (2)	Forecast 2033 (2)	Forecast 2034 (2)	Forecast 2035 (2)	Forecast 2036 (2)
Long Term Debt Balance	23,907	23,358	22,956	22,206	21,608	21,391	21,173	19,494	18,922	18,002	17,112	16,620	16,117
Short Term Debt Balance	-	-	-	-	-	-	-	11	-	45	42	-	-
Trust Investment from Pre-Financing	(249)												
PGF Assessed On	23,658	23,358	22,956	22,206	21,608	21,391	21,173	19,506	18,922	18,048	17,154	16,620	16,117
Guarantee Fee Rate	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %	1.00 %
Amount Paid to Province	237	234	230	222	216	214	212	195	189	180	172	166	161
Portion Allocated to Centra	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)
Net MB Hydro Provincial Debt Guarantee Fee	**232**	**229**	**225**	**217**	**211**	**209**	**206**	**190**	**184**	**175**	**166**	**160**	**155**

Notes: (1) The fee calculation is based on ending principal par value debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the debt guarantee fee on bonds issued for mitigation purposes. The long term debt balance presented in Payments to Government MFR 2 represents that amount of debt upon which the Provincial Debt Guarantee Fee was paid or is payable.

(2) US Dollar long term debt balance at March 31, 2017 was converted at forecast year end exchange rate of 1.30 for the assessment of the 2018 PGF.
US Dollar long term debt balances at March 31, 2018, 2019, 2020 and 2021 were converted at forecast year end exchange rate of 1.28, 1.25, 1.21, 1.21 respectively for the assessment of the PGF for years 2019, 2020, 2021 and 2022.
US Dollar long term debt balances at March 31, 2022 and beyond were converted at forecast year end exchange rate of 1.15 for the assessment of the PGF for years 2023 and beyond.

PUB MFR 46

Payments to Government

A schedule detailing the calculation of the water rental payments for the last five historical years and through the twenty year forecast period. [Appendix 11.34, 2015/16 GRA]

Please see **Table 1** below for the calculations of the water rental payments from fiscal 2011/12 to fiscal 2035/36.

Table 1 Water Rental Payments Calculations

Water Rental Calculation

	Actual 2012	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	
Megawatt-Hours Generated (million mWh)	33.2	33.1	35.3	35.0	34.9	
Converted to Horsepower-years	5.5	5.5	5.8	5.8	5.7	(1)
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32	(2)
Calculated Water Annual Rental ($ million)	$ 110.8	$ 110.8	$ 117.9	$ 116.9	$ 116.8	
Minimum Rental Adjustment				0.1		(3)
Other Adjustment		(0.4)				(4)
Total Water Rentals	$ 110.8	$ 110.4	$ 117.9	$ 117.0	$ 116.8	

(1) The Water Power Act defines "Horsepower-year" as kW.h/6535 X 1.075.

(2) The water rental fee was calculated at a rate of 9.90 per Horsepower-year generated up to March 31, 2001. Effective April 1, 2001 the rate was increased to its current level of $20.32 per Horsepower-year.

(3) The Water Power Act of Manitoba provides that the water rentals charged for each generation site be the greater of (a) a fixed rate multiplied by the installed capacity of that site and (b) a fixed rate multiplied by the electrical output for the year of that site. Generally , the calculation under (b) based on actual output results in the greatest amount for each generation site. In some years, such as in 2015, it is necessary to adjust the amounts calculated under the (b) calculation for some specific sites to bring the total up to the amount calculated under the (a) installed capacity calculation method.

(4) Water rentals relating to the Wuskwatim Generating Station were calculated at a reduced rate during the commissioning process. The full rental rate of $20.32 per Horsepower-year was charged commencing October 6, 2012.

Water Rental Calculation

	Outlook 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
Megawatt-Hours Generated (million mWh)	36.5	34.3	30.8	31.1	31.3
Converted to Horsepower-years	6.0	5.6	5.1	5.1	5.1
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 122.0	$ 114.7	$ 103.1	$ 104.0	$ 104.6

	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026
Megawatt-Hours Generated (million mWh)	32.3	35.2	35.4	35.4	35.4
Converted to Horsepower-years	5.3	5.8	5.8	5.8	5.8
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 108.0	$ 117.7	$ 118.4	$ 118.4	$ 118.4

	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031
Megawatt-Hours Generated (million mWh)	35.4	35.4	35.4	35.4	35.4
Converted to Horsepower-years	5.8	5.8	5.8	5.8	5.8
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 118.4	$ 118.4	$ 118.4	$ 118.4	$ 118.3

	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Megawatt-Hours Generated (million mWh)	35.4	35.4	35.4	35.4	35.3
Converted to Horsepower-years	5.8	5.8	5.8	5.8	5.8
Rental Rate per Horsepower-year	20.32	20.32	20.32	20.32	20.32
Total Water Rentals ($ million)	$ 118.3	$ 118.3	$ 118.3	$ 118.2	$ 118.2

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REFERENCE:

MFR 45 and 46

PREAMBLE TO IR (IF ANY):

QUESTION:

Quantify all payments to Government included in the forecast, by year, for Keeyask (by component) and for Bipole III (by component) and also as a percentage of MH's gross revenues.

RATIONALE FOR QUESTION:

RESPONSE:

The following tables quantify payments to the Government for the Keeyask and Bipole III projects. Please note the following assumptions:

- Water rental payments have been assigned based on the forecasted supply for the Keeyask Generating Station. No such payment is applicable to Bipole III.

- Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, the Provincial Guarantee Fee (PGF) attributable to a specific project is estimated for the purposes of this analysis by applying the 1% PGF to construction work in progress until the asset is in-service and the net book value (projected in-service cost net of accumulated depreciation) thereafter.

- Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as a proxy for paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

KEEYASK PROJECT - PAYMENTS MADE TO PROVINCE OF MANITOBA
MILLIONS OF DOLLARS

FISCAL YR ENDING	WATER RENTALS	PGF	CAPITAL TAX	TOTAL PMTS TO GOVT	TOTAL ELECTRIC DOMESTIC REVENUE	GOVT PMTS AS A % OF TOTAL DOMESTIC REVENUE
2017	-	33	16	49	1 419	3.5%
2018	-	44	22	65	1 464	4.5%
2019	-	56	28	85	1 746	4.8%
2020	-	68	34	101	1 946	5.2%
2021	-	76	38	114	2 075	5.5%
2022	4	83	42	129	2 243	5.7%
2023	14	85	43	142	2 410	5.9%
2024	15	85	42	142	2 541	5.6%
2025	18	84	42	143	2 647	5.4%
2026	18	82	41	141	2 724	5.2%
2027	18	81	41	139	2 807	5.0%
2028	18	80	40	138	2 893	4.8%
2029	18	79	39	136	2 979	4.6%
2030	18	77	39	134	3 069	4.4%
2031	18	76	38	133	3 163	4.2%
2032	18	75	38	131	3 277	4.0%
2033	19	74	37	129	3 397	3.8%
2034	19	73	36	128	3 521	3.6%
2035	19	71	36	126	3 651	3.5%
2036	19	70	35	124	3 785	3.3%

BIPOLE III PROJECT - PAYMENTS MADE TO PROVINCE OF MANITOBA
MILLIONS OF DOLLARS

FISCAL YR ENDING	PGF	CAPITAL TAX	TOTAL PMTS TO GOVT	TOTAL ELECTRIC DOMESTIC REVENUE	GOVT PMTS AS A % OF TOTAL DOMESTIC REVENUE
2017	32	16	48	1 419	3.4%
2018	43	22	65	1 464	4.4%
2019	49	25	74	1 746	4.2%
2020	49	25	74	1 946	3.8%
2021	49	24	73	2 075	3.5%
2022	48	24	73	2 243	3.2%
2023	48	24	72	2 410	3.0%
2024	47	24	71	2 541	2.8%
2025	46	23	69	2 647	2.6%
2026	45	23	68	2 724	2.5%
2027	44	22	66	2 807	2.3%
2028	43	21	64	2 893	2.2%
2029	42	21	63	2 979	2.1%
2030	41	20	61	3 069	2.0%
2031	40	20	60	3 163	1.9%
2032	39	19	58	3 277	1.8%
2033	38	19	56	3 397	1.7%
2034	37	18	55	3 521	1.6%
2035	35	18	53	3 651	1.5%
2036	34	17	52	3 785	1.4%

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Figure 6.24 Capital and Other Taxes breakdown

MANITOBA HYDRO
CAPITAL AND OTHER TAXES
(000's)

	2014/15 Actual	**2015/16 Actual**	**2016/17 Outlook**	**2017/18 Forecast**	**2018/19 Forecast**
Capital tax	$ 62 299	$ 69 372	$ 78 707	$ 92 763	$ 104 553
Grants in lieu of taxes	25 199	25 192	26 642	26 187	26 944
Payroll tax	11 636	11 909	12 288	12 740	13 002
GST reassessment on city tax	620	66	-	-	-
Total capital & other taxes	$ 99 754	$ 106 539	$ 117 637	$ 131 690	$ 144 499
Year over year $ change		$ 6 785	$ 11 098	$ 14 052	$ 12 810
Year over year % change		6.8%	10.4%	11.9%	9.7%

The following provides a description of capital & other tax components:

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

The corporation pays grants in lieu on its land and buildings. The amount of grants in lieu paid is determined based on property valuations and municipal and school division mill rates, similar to the manner in which property taxes are determined for other tax payers in Manitoba.

Payroll tax is based on a tax rate of 2.15% which is applied to the corporation's gross payroll

Business taxes are paid with respect to commercial space occupied by the company in both leased and owned properties. The corporation pays property taxes to the landlords of leased premises as part of the required lease payments.

The corporation also makes other municipal payments with respect to the town of Gillam and the Frontier School Division.

REFERENCE:

Tab 6, Pages 33-35

PREAMBLE TO IR (IF ANY):

At Tab 6, page 34 the Application states that capital tax is based on 0.5% of taxable capital. However the discussion on page 35 links changes in capital tax to changes in debt level.

QUESTION:

a) Please explain how the capital tax in any particular year is determined and precisely what the 0.5% is applied to.

b) In particular, do the balances in Manitoba Hydro's regulatory deferral accounts have any effect on the calculation of capital taxes?

RATIONALE FOR QUESTION:

To clarify the basis for determining capital taxes

RESPONSE:

a) Capital tax is calculated on the total paid up capital less the investment allowance multiplied by 0.5%. Please see the following table for an illustration of the calculation.

+ Debt
+ Retained earnings
+/- Accumulated other comprehensive income
= Total paid up capital

+ Temporary investments
+ Sinking fund assets
+ Pension assets
+ Investment in subsidiaries
+ Loans to subsidiaries
= Eligible assets

+ Total paid up capital
- Investment allowance ((Eligible assets/total assets) X total paid up capital)
= Taxable paid up capital

X 0.5%

= Capital tax payable

b) Regulatory deferral accounts that are in a debit balance are included in "total assets" which is the denominator in the investment allowance calculation. The regulatory deferral asset balances increased capital tax by approximately $0.3 million in fiscal 2016/17.

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REFERENCE:

Tab 6 page 27 Figure 6.18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file an update to figure 6.18 schedule detailing depreciation and amortization expense including the years 2019/20 to 2023/24.

b) Please provide the same table as in (a) based on Board approved 2014 ASL rates (no net salvage).

RATIONALE FOR QUESTION:

RESPONSE:

a) As requested figure 6.18 has been updated to include the years 2019/20 to 2023/24.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
ELG rates (no net salvage)
(in thousands)

	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast
PROPERTY, PLANT & EQUIPMENT					
Generation					
Hydraulic Generating Stations	122 805	124 673	148 515	230 923	246 115
Thermal Generating Stations	15 923	15 963	16 003	16 380	17 094
Diesel Generating Stations	2 041	3 690	4 285	4 292	4 300
	140 769	144 325	168 803	251 596	267 510
Transmission					
Transmission	41 178	45 622	48 285	51 634	52 399
	41 178	45 622	48 285	51 634	52 399
Stations					
Substations	162 625	168 005	169 949	171 568	174 081
Transformers	1 804	1 804	1 682	1 671	1 681
	164 428	169 809	171 632	173 240	175 763
Distribution					
Subtransmission Lines	8 435	9 046	9 777	10 234	10 680
Distribution Lines	71 119	74 686	78 470	82 279	86 103
Meters & Transformers	6 220	6 241	6 334	6 441	6 557
	85 775	89 973	94 580	98 955	103 340
Other					
Communications	24 807	24 588	24 230	23 007	23 096
Motor Vehicles	14 672	15 163	15 459	15 784	16 129
Structures & Improvements	10 481	10 891	11 109	11 212	11 308
General Equipment	18 140	17 918	18 221	18 284	18 351
Miscellaneous	(9 320)	(10 151)	(9 910)	(9 986)	(10 111)
Corporate Allocation	(1 372)	(1 309)	(1 003)	(1 003)	(1 003)
	57 408	57 101	58 107	57 297	57 770
Total Depreciation on PP & E	**489 558**	**506 829**	**541 407**	**632 722**	**656 781**
INTANGIBLES					
Computer Development	23 754	24 666	25 740	26 487	27 325
Easements	2 092	2 291	2 346	2 346	2 346
Transmission Rights		21 205	27 762	27 762	27 762
Total Amortization on Intangibles	**25 845**	**48 162**	**55 848**	**56 595**	**57 433**
Loss on Disposition	-	-	-	-	-
Total Loss on Disposition	**-**	**-**	**-**	**-**	**-**
Total Depreciation & Amortization Expense ***	**$ 515 404**	**$ 554 991**	**$ 597 255**	**$ 689 317**	**$ 714 214**
Year over year $ change	44 565	39 587	42 264	92 062	24 897
Year over year % change	9.5%	7.7%	7.6%	15.4%	3.6%

**** Amounts for change in depreciation method and loss on disposal have been deferred in compliance with PUB Order 73/15 and are reflected in Net Movement*

b) The table in part (a) has been reproduced using the 2014 ASL rates (no net salvage) below.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
ASL rates (no net salvage)
(in thousands)

	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast
PROPERTY, PLANT & EQUIPMENT					
Generation					
Hydraulic Generating Stations	114 132	115 920	138 413	216 076	230 382
Thermal Generating Stations	14 967	15 007	15 047	15 405	16 081
Diesel Generating Stations	1 777	3 270	3 807	3 814	3 820
	130 876	134 197	157 267	235 294	250 283
Transmission					
Transmission	38 244	42 376	44 141	44 623	44 935
	38 244	42 376	44 141	44 623	44 935
Stations					
Substations	149 165	153 964	155 714	157 237	159 614
Transformers	1 748	1 748	1 632	1 622	1 632
	150 914	155 713	157 346	158 859	161 246
Distribution					
Subtransmission Lines	6 777	7 290	7 902	8 298	8 678
Distribution Lines	60 612	63 701	66 975	70 271	73 557
Meters & Transformers	5 865	5 876	5 953	6 045	6 144
	73 253	76 866	80 830	84 614	88 379
Other					
Communications	22 788	22 531	22 139	20 891	20 955
Motor Vehicles	13 406	13 848	14 108	14 393	14 695
Structures & Improvements	9 799	10 173	10 372	10 456	10 533
General Equipment	18 140	17 918	18 221	18 284	18 351
Miscellaneous	(9 059)	(9 880)	(9 624)	(9 645)	(9 692)
Corporate Allocation	(1 372)	(1 309)	(1 003)	(1 003)	(1 003)
	53 703	53 281	54 214	53 375	53 839
Total Depreciation on PP & E	**446 989**	**462 434**	**493 798**	**576 766**	**598 681**
INTANGIBLES					
Computer Development	23 454	24 359	25 425	26 164	26 995
Easements	2 092	2 291	2 346	2 346	2 346
Transmission Rights	-	21 205	27 762	27 762	27 762
Total Amortization on Intangibles	**25 546**	**47 855**	**55 533**	**56 272**	**57 102**
Loss on Disposition	-	-	-	-	-
Total Loss on Disposition	**-**	**-**	**-**	**-**	**-**
Total Depreciation & Amortization Expense	**472 535**	**510 289**	**549 331**	**633 038**	**655 783**
Year over year $ change	41 119	37 754	39 042	83 707	22 745
Year over year % change	9.5%	8.0%	7.7%	15.2%	3.6%

REFERENCE:

PUB MFR 22
Tab 6, Page 42
2015/16 & 2016/17 GRA, Appendix 3.3, Page 36

PREAMBLE TO IR (IF ANY):

QUESTION:

c) After allowing for the factors noted in parts (a) and (b) is the Depreciation forecast in MH14 for the years 2014/15 through 2018/19 comparable to that in the actual values reported and MH16? If not, please provide a schedule that expresses the two on a comparable basis and indicates the items contributing to the difference.

d) Please provide the MH14 forecast for Depreciation for 2019/20 through to 2033/34 without the inclusion of the amortization of the BP III Reserve account. In the same schedule, please include i) MH16 Depreciation forecast and ii) the annual adjustments required to the MH16 forecast to make it comparable to the MH14 forecast in terms of the cost items included.

e) Please confirm that the MH15 and MH 16 Depreciation forecast for the period up to 2033/34 are prepared on a comparable basis (i.e., the same cost items are reflected in both). If not, please provide a schedule that identifies the difference in items included for the year through to 2033/34.

RATIONALE FOR QUESTION:

To understand the basis for the Depreciation charges included in MH16 and the changes from previous forecasts.

RESPONSE:

c) After allowing for the factors noted in parts (a) and (b), the depreciation forecast in MH14 is comparable to that in the actual values reported, and MH16 Update with Interim. Please see table below for the adjusted MH14 depreciation balances.

Manitoba Hydro
Depreciation and Amortization
MH14 comparable to MH16
(in thousands)

	2014/15	2015/16	2016/17	2017/18	2018/19
As reported in MH14 *	404 590	400 866	422 404	445 218	521 299
Removal of Net Salvage **	(57 107)	-	-	-	-
ELG to ASL depreciation valuation adjustment **	33 088	-	-	-	-
Reclassified to Net Movement in Regulatory Deferral Accounts					
Power Smart programs	(31 576)	(34 957)	(37 501)	(40 952)	(44 541)
Site restoration costs	(3 791)	(3 725)	(3 713)	(3 658)	(3 403)
Regulatory costs	(27)	(765)	(1 307)	(739)	(761)
Acquisition costs	(692)	(692)	(692)	(692)	(692)
Affordable energy fund	(5 270)	(4 290)	(1 509)	(209)	(110)
Amortization of Contributions reclassified to Other Income	9 366	10 164	10 764	11 348	11 941
Adjusted MH14	348 581	366 601	388 446	410 316	483 733

* Depreciation and amortization reported in MH14 for 2014/15 are CGAAP amounts.
** Commencing in 2015/16 MH14 is based on ELG depreciation rates with the removal of net salvage.

d) Please see table below for MH16 depreciation and amortization forecast with required adjustments to make it comparable to MH14 without the inclusion of the BPIII Reserve account. Please note, for the period in the table below both MH14 and MH16 use ELG depreciation rates with the removal of net salvage.

Manitoba Hydro
Depreciation and Amortization Forecast
For MH16 compared to MH14
(in thousands)

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
MH16 Update with Interim Rates	515 404	554 991	597 255	689 317	714 214	726 038	739 343	751 967	764 666	775 607	790 375	805 029	822 330	840 103	856 546
Adjustments															
Power Smart Programs	43 202	49 473	55 519	61 480	65 459	68 888	71 976	73 251	75 309	77 059	75 008	73 863	73 203	72 900	74 807
Site Restoration Costs	3 855	3 559	2 990	2 629	2 234	2 170	1 991	1 826	1 724	1 514	1 334	1 046	891	616	433
Regulatory Costs	2 884	2 495	1 883	1 400	1 657	1 684	1 721	1 749	1 789	1 821	1 866	1 900	1 947	1 982	2 031
Acquisition costs	692	692	692	692	692	692	692	692	692	692	678	300	300	199	6
Affordable Energy Fund	563	545	511	489	454	322	147	97	95	-	-	-	-	-	-
Conawapa	11 592	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645
Amortization of Contributions	(11 313)	(12 162)	(12 665)	(12 607)	(12 339)	(12 601)	(12 732)	(13 043)	(13 281)	(13 547)	(13 791)	(14 000)	(14 319)	(14 400)	(14 415)
MH16 comparable to MH14	566 880	612 237	658 829	756 045	785 015	799 839	815 782	829 185	843 639	855 791	868 117	880 783	896 997	914 044	932 053
MH14 Depreciation and Amortization	524 325	612 653	666 542	736 255	752 152	767 373	779 908	791 208	803 923	811 283	820 324	831 047	842 420	856 532	872 691
Remove BPIII Reserve account	53 895	53 895	53 895	-	-	-	-	-	-	-	-	-	-	-	-
Adjusted MH14	578 220	666 548	720 437	736 255	752 152	767 373	779 908	791 208	803 923	811 283	820 324	831 047	842 420	856 532	872 691

e) The depreciation forecast in MH15 and MH16 Update with Interim for the period up to 2033/34 are prepared on a comparable basis.

75

REFERENCE:

PUB/MH I-26

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file updates to schedules detailing the accumulated depreciation variance (Appendix 5.6 Attachment 1 and Attachment 2 – Table 2: Calculated Accrued Depreciation, Book Accumulated Depreciations and Determination of Annual Provision for the True-Up (2015/16 GRA))

b) Please provide an update to MIPUG/MH I-22(b) Attachment 1 Page 20 (2015/16 GRA)

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) and b):

Manitoba Hydro is unable to file updates to the 2014 Depreciation Study schedules as neither a formal depreciation study or technical update has been performed since the completion of the 2014 study. The Corporation's practice is that such studies are typically conducted every five years. In order to update this information, Manitoba Hydro would need to formally engage a depreciation consultant.

Section:	Appendix 5.6	**Page No.:**	Page 7 - 14
Topic:	Depreciation		
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide pages 7 through 14 separately breaking out the net salvage component of the ASL rates from the asset life depreciation component.

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study and implications on rate payers.

RESPONSE:

Please see the schedules below breaking out the net salvage component of the ASL rates from the asset life component.

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
HYDRAULIC GENERATION					
GREAT FALLS					
DAMS, DYKES AND WEIRS	125	1.28	1.32	1.11	1.12
POWERHOUSE	125	1.27	1.28	1.07	1.07
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.59	1.50	1.26	1.35
WATER CONTROL SYSTEMS	65	2.07	1.52	1.28	1.35
ROADS AND SITE IMPROVEMENTS	50	2.33	2.42	2.18	2.42
TURBINES AND GENERATORS	60	1.82	2.25	1.99	2.03
GOVERNORS AND EXCITATION SYSTEM	50	2.11	2.25	1.99	2.06
LICENCE RENEWAL	50	2.00	2.04	2.04	2.04
A/C ELECTRICAL POWER SYSTEMS	55	2.10	1.84	1.55	1.67
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.43	3.86	3.20	3.79
AUXILIARY STATION PROCESSES	50	2.59	2.03	1.75	2.10
SUPPORT BUILDINGS	65	1.73	1.69	1.42	1.36
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
POINTE DU BOIS - Original					
DAMS, DYKES AND WEIRS	125	3.63	3.10	2.70	2.70
POWERHOUSE	125	4.39	2.94	2.55	2.55
POWERHOUSE RENOVATIONS	40	5.24	4.10	3.71	3.71
SPILLWAY	80	10.76	84.53	73.57	73.37
WATER CONTROL SYSTEMS	65	3.35	2.11	1.72	1.73
ROADS AND SITE IMPROVEMENTS	50	3.36	4.09	3.68	3.80
TURBINES AND GENERATORS	60	4.04	2.84	2.44	2.44
GOVERNORS AND EXCITATION SYSTEM	50	5.24	4.02	3.65	3.68
LICENCE RENEWAL	50	4.76	3.85	3.85	3.85
A/C ELECTRICAL POWER SYSTEMS	55	4.58	3.16	2.76	2.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.12	4.30	3.80	4.26
AUXILIARY STATION PROCESSES	50	4.03	3.71	3.29	3.59
SUPPORT BUILDINGS	65	2.93	2.99	2.59	2.59
SUPPORT BUILDING RENOVATIONS	20	5.50	4.47	3.84	3.84
POINTE DU BOIS - New					
DAMS, DYKES AND WEIRS	125	-	0.91	0.83	0.85
SPILLWAY	80	1.47	1.37	1.25	1.49
WATER CONTROL SYSTEMS	65	-	1.69	1.54	1.64
ROADS AND SITE IMPROVEMENTS	50	-	2.20	2.00	2.36
A/C ELECTRICAL POWER SYSTEMS	55	-	2.40	2.18	1.94
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	-	4.40	4.00	4.54
AUXILIARY STATION PROCESSES	50	-	2.20	2.00	3.01
SUPPORT BUILDINGS	65	-	1.69	1.54	1.65
SUPPORT BUILDING RENOVATIONS	20	-	5.50	5.00	5.00
SEVEN SISTERS					
DAMS, DYKES AND WEIRS	125	1.03	1.06	0.88	0.90
POWERHOUSE	125	0.90	0.91	0.73	0.74
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.17	1.36	1.14	1.17
WATER CONTROL SYSTEMS	65	1.80	1.25	1.02	1.02
ROADS AND SITE IMPROVEMENTS	50	1.84	1.78	1.46	1.30
TURBINES AND GENERATORS	60	1.64	1.84	1.61	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.00	2.22	1.99	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.91	1.74	1.48	1.56
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	3.73	3.80	3.19	3.44
AUXILIARY STATION PROCESSES	50	2.13	1.91	1.65	2.03
SUPPORT BUILDINGS	65	1.74	1.65	1.44	1.52
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
SLAVE FALLS					
DAMS, DYKES AND WEIRS	125	1.69	1.71	1.54	1.54
POWERHOUSE	125	1.58	1.59	1.42	1.43
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.87	1.82	1.64	1.74
WATER CONTROL SYSTEMS	65	2.18	1.77	1.58	1.65
ROADS AND SITE IMPROVEMENTS	50	2.20	2.30	2.08	2.36
TURBINES AND GENERATORS	60	1.79	1.91	1.70	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.22	2.01	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	2.00	1.79	1.91
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.72	4.42	3.96	4.56
AUXILIARY STATION PROCESSES	50	2.73	2.34	2.11	2.70
SUPPORT BUILDINGS	65	1.81	2.01	1.81	1.89
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
PINE FALLS					
DAMS, DYKES AND WEIRS	125	1.17	1.23	1.10	1.12
POWERHOUSE	125	0.83	0.83	0.67	0.71
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.60	1.50	1.35	1.49
WATER CONTROL SYSTEMS	65	1.95	1.28	1.03	1.06
ROADS AND SITE IMPROVEMENTS	50	1.81	1.68	2.00	1.61
TURBINES AND GENERATORS	60	1.47	1.62	1.33	1.37
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.00	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.06	1.83	1.56	1.58
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.25	4.17	3.61	4.04
AUXILIARY STATION PROCESSES	50	2.54	1.78	1.50	1.81
SUPPORT BUILDINGS	65	1.61	1.62	1.40	1.56
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
COMMUNITY DEVELOPMENT COSTS	78	1.17	1.28	1.28	1.28
MCARTHUR FALLS					
DAMS, DYKES AND WEIRS	125	0.91	1.12	0.98	1.00
POWERHOUSE	125	0.83	0.84	0.68	0.72
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.19	1.19	0.86	0.97
WATER CONTROL SYSTEMS	65	2.06	1.37	1.15	1.25
ROADS AND SITE IMPROVEMENTS	50	1.99	1.94	1.59	1.71
TURBINES AND GENERATORS	60	1.06	1.35	0.97	0.94
GOVERNORS AND EXCITATION SYSTEM	50	2.10	2.08	1.78	1.94
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.90	1.72	1.37	1.32
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.29	3.62	2.88	2.74
AUXILIARY STATION PROCESSES	50	2.58	1.82	1.54	1.85
SUPPORT BUILDINGS	65	1.63	1.73	1.57	1.67
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
KELSEY					
DAMS, DYKES AND WEIRS	125	1.05	1.13	1.01	1.03
POWERHOUSE	125	0.89	1.18	1.06	1.08
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.34	1.71	1.47	1.58
WATER CONTROL SYSTEMS	65	2.09	1.70	1.52	1.61
ROADS AND SITE IMPROVEMENTS	50	2.05	2.44	2.13	2.30
TURBINES AND GENERATORS	60	1.68	1.90	1.72	1.85
GOVERNORS AND EXCITATION SYSTEM	50	2.14	2.25	2.04	2.17
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.03	2.11	1.91	2.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.67	4.14	4.62
AUXILIARY STATION PROCESSES	50	2.63	2.19	1.92	2.31
SUPPORT BUILDINGS	65	1.67	1.79	1.60	1.73
SUPPORT BUILDING RENOVATIONS	20	4.98	4.98	4.44	4.44
GRAND RAPIDS					
DAMS, DYKES AND WEIRS	125	0.98	1.01	0.87	0.90
POWERHOUSE	125	0.91	0.92	0.77	0.81
POWERHOUSE RENOVATIONS	40	4.40	2.55	2.28	2.28
SPILLWAY	80	1.30	1.28	1.01	1.15
WATER CONTROL SYSTEMS	65	1.79	1.10	0.95	0.99
ROADS AND SITE IMPROVEMENTS	50	1.68	1.63	1.23	1.21
TURBINES AND GENERATORS	60	1.64	1.82	1.59	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.13	2.21	2.00	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.07	1.84	1.57	1.66
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.08	3.90	2.99	2.49
AUXILIARY STATION PROCESSES	50	2.62	2.02	1.78	2.29
SUPPORT BUILDINGS	65	1.66	1.69	1.46	1.60
SUPPORT BUILDING RENOVATIONS	20	5.50	5.67	5.00	5.00
COMMUNITY DEVELOPMENT COSTS ***	79	1.16	1.21	1.21	1.21
KETTLE					
DAMS, DYKES AND WEIRS	125	0.86	0.86	0.73	0.78
POWERHOUSE	125	0.87	0.86	0.74	0.79
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.33	1.26	1.03	1.16
WATER CONTROL SYSTEMS	65	1.55	0.99	0.81	0.89
ROADS AND SITE IMPROVEMENTS	50	2.14	2.20	1.99	2.31
TURBINES AND GENERATORS	60	1.48	1.90	1.62	1.73
GOVERNORS AND EXCITATION SYSTEM	50	1.66	2.14	1.84	1.92
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.04	2.04	1.84	1.96
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.11	4.20	3.55	3.37
AUXILIARY STATION PROCESSES	50	2.44	1.82	1.57	1.86
SUPPORT BUILDINGS	65	1.46	1.75	1.58	1.70
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
LAURIE RIVER					
DAMS, DYKES AND WEIRS	125	3.47	3.20	2.70	2.70
POWERHOUSE	125	4.25	3.89	3.39	3.40
POWERHOUSE RENOVATIONS	40	5.00	5.24	4.76	4.76
SPILLWAY	80	3.88	3.44	2.94	2.96
WATER CONTROL SYSTEMS	65	3.84	3.52	3.02	3.03
ROADS AND SITE IMPROVEMENTS	50	4.01	3.69	3.15	3.23
TURBINES AND GENERATORS	60	4.49	4.11	3.62	3.62
GOVERNORS AND EXCITATION SYSTEM	50	4.70	4.29	3.79	3.81
LICENCE RENEWAL	50	4.55	4.76	4.76	4.76
A/C ELECTRICAL POWER SYSTEMS	55	4.08	3.63	3.12	3.15
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	7.23	6.28	4.87	5.15
AUXILIARY STATION PROCESSES	50	4.30	3.73	3.19	3.31
SUPPORT BUILDINGS	65	3.75	3.36	2.85	2.87
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
JENPEG					
DAMS, DYKES AND WEIRS	125	0.92	0.91	0.80	0.84
POWERHOUSE	125	0.89	0.90	0.78	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.48	2.48
SPILLWAY	80	1.42	1.35	1.14	1.28
WATER CONTROL SYSTEMS	65	2.02	1.24	0.95	1.07
ROADS AND SITE IMPROVEMENTS	50	2.12	2.07	1.68	1.87
TURBINES AND GENERATORS	60	1.63	1.89	1.59	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.00	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.05	1.81	1.42	1.53
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.53	4.15	3.17	3.39
AUXILIARY STATION PROCESSES	50	2.66	1.92	1.67	2.06
SUPPORT BUILDINGS	65	1.67	1.69	1.46	1.61
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
LAKE WINNIPEG REGULATION					
DAMS, DYKES AND WEIRS	125	0.82	0.82	0.71	0.77
LICENCE RENEWAL	50	2.00	2.02	2.02	2.02
COMMUNITY DEVELOPMENT COSTS	85	0.94	1.18	1.18	1.18
CHURCHILL RIVER DIVERSION					
DAMS, DYKES AND WEIRS	125	0.88	0.88	0.77	0.83
SPILLWAY	80	1.47	1.39	1.18	1.32
WATER CONTROL SYSTEMS	65	2.21	1.17	0.88	1.00
ROADS AND SITE IMPROVEMENTS	50	2.21	2.11	1.63	1.78
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	1.88	1.45	1.57
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.82	4.78	3.01	2.36
AUXILIARY STATION PROCESSES	50	2.75	1.97	1.70	2.11
SUPPORT BUILDINGS	65	1.69	1.71	1.54	1.66
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
COMMUNITY DEVELOPMENT COSTS	90	0.93	1.07	1.07	1.07

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
LONG SPRUCE					
DAMS, DYKES AND WEIRS	125	0.90	0.90	0.79	0.83
POWERHOUSE	125	0.90	0.90	0.79	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.43	1.36	1.15	1.30
WATER CONTROL SYSTEMS	65	2.04	0.99	0.66	0.78
ROADS AND SITE IMPROVEMENTS	50	2.10	2.07	1.69	1.87
TURBINES AND GENERATORS	60	1.63	1.88	1.50	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.19	2.18	1.93	2.08
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.09	1.79	1.37	1.51
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.37	4.37	3.81	3.87
AUXILIARY STATION PROCESSES	50	2.63	1.60	1.30	1.53
SUPPORT BUILDINGS	65	1.69	1.69	1.51	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.90	4.90
LIMESTONE					
DAMS, DYKES AND WEIRS	125	0.90	0.91	0.81	0.85
POWERHOUSE	125	0.91	0.91	0.81	0.85
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.45	1.37	1.20	1.37
WATER CONTROL SYSTEMS	65	2.17	1.39	1.16	1.28
ROADS AND SITE IMPROVEMENTS	50	2.17	2.14	1.80	2.03
TURBINES AND GENERATORS	60	1.68	1.90	1.63	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.17	2.15	1.80	1.96
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.17	1.89	1.59	1.73
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.67	4.16	3.16	3.48
AUXILIARY STATION PROCESSES	50	2.71	1.78	1.47	1.80
SUPPORT BUILDINGS	65	1.68	1.71	1.48	1.63
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.89	4.89
WUSKWATIM					
DAMS, DYKES AND WEIRS	125	0.88	0.91	0.82	0.87
POWERHOUSE	125	0.88	0.91	0.83	0.87
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.47	1.36	1.24	1.46
WATER CONTROL SYSTEMS	65	2.20	1.68	1.52	1.62
ROADS AND SITE IMPROVEMENTS	50	2.20	2.19	1.99	2.32
TURBINES AND GENERATORS	60	1.69	1.83	1.66	1.78
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.19	1.98	2.12
A/C ELECTRICAL POWER SYSTEMS	55	2.20	1.99	1.81	1.92
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.78	4.24	3.83	4.39
AUXILIARY STATION PROCESSES	50	2.75	2.13	1.93	2.93
SUPPORT BUILDINGS	65	1.69	1.69	1.53	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
INFRASTRUCTURE SUPPORTING GENERATION					
PROVINCIAL ROADS	50	2.30	2.49	2.02	2.21
TOWN SITE BUILDING	55	1.71	2.12	1.93	2.03
TOWN SITE BUILDINGS RENOVATIONS	20	5.94	5.30	5.00	5.00
TOWN SITE OTHER INFRASTRUCTURE	45	2.49	3.11	2.77	2.93

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
THERMAL GENERATION					
BRANDON UNIT 5 (COAL)					
POWERHOUSE	75	3.87	4.52	4.52	4.50
POWERHOUSE RENOVATIONS	40	10.00	15.88	15.88	15.88
ROADS AND SITE IMPROVEMENTS	50	4.56	5.37	5.37	5.36
THERMAL TURBINES AND GENERATORS	60	5.03	5.73	5.73	5.72
GOVERNORS AND EXCITATION SYSTEM	50	5.07	5.51	5.51	5.52
STEAM GENERATOR AND AUXILIARIES	60	3.93	4.06	4.06	4.05
LICENCE RENEWAL	50	10.00	14.81	14.81	14.81
A/C ELECTRICAL POWER SYSTEMS	55	4.06	4.65	4.65	4.64
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.41	4.44	4.44	4.41
AUXILIARY STATION PROCESSES	50	4.67	5.36	5.36	5.37
SUPPORT BUILDINGS	65	4.25	5.97	5.97	5.97
SUPPORT BUILDING RENOVATIONS	20	10.00	16.67	16.67	16.67
BRANDON UNITS 6 AND 7					
POWERHOUSE	75	1.65	1.38	1.22	1.26
POWERHOUSE RENOVATIONS	40	4.40	2.72	2.46	2.46
THERMAL TURBINES AND GENERATORS	60	2.12	1.70	1.49	1.64
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.00	2.13
COMBUSTION TURBINE	25	4.05	3.87	3.18	3.66
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
COMBUSTION TURBINE OVERHAULS	15	11.00	7.33	6.67	6.67
A/C ELECTRICAL POWER SYSTEMS	55	2.12	1.88	1.65	1.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.52	4.00	4.63
AUXILIARY STATION PROCESSES	50	2.64	1.91	1.66	2.10
SELKIRK					
POWERHOUSE	75	0.93	0.76	0.76	0.79
POWERHOUSE RENOVATIONS	40	4.00	2.45	2.45	2.45
ROADS AND SITE IMPROVEMENTS	50	1.35	1.34	1.34	1.42
THERMAL TURBINES AND GENERATORS	60	1.46	1.09	1.09	1.18
GOVERNORS AND EXCITATION SYSTEM	50	2.00	1.13	1.13	1.30
STEAM GENERATOR AND AUXILIARIES	60	1.34	1.49	1.49	1.66
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.21	1.06	1.06	1.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	2.41	2.11	2.11	2.40
AUXILIARY STATION PROCESSES	50	1.64	1.19	1.19	1.44
SUPPORT BUILDINGS	65	1.06	1.06	1.06	1.13
SUPPORT BUILDING RENOVATIONS	20	5.00	5.00	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
DIESEL GENERATION					
BUILDINGS	25	2.57	3.15	2.78	3.17
BUILDING RENOVATIONS	15	5.14	6.67	6.67	6.67
ENGINES AND GENERATORS - OVERHAULS	4	20.00	25.00	25.00	25.00
ENGINES AND GENERATORS	22	1.88	2.24	2.24	2.73
ACCESSORY STATION EQUIPMENT	20	3.07	3.70	3.38	3.67
FUEL STORAGE AND HANDLING	25	2.28	2.37	2.09	2.60
TRANSMISSION					
ROADS, TRAILS AND BRIDGES	50	2.51	2.19	1.96	2.18
METAL TOWERS AND CONCRETE POLES	85	1.51	1.54	1.16	1.23
POLES AND FIXTURES	55	2.49	2.48	1.59	1.80
GROUND LINE TREATMENT	10	10.00	10.00	10.00	10.00
OVERHEAD CONDUCTOR AND DEVICES	80	1.62	1.27	1.02	1.10
UNDERGROUND CABLE AND DEVICES	45	2.23	1.96	1.63	1.81
COMMUNITY DEVELOPMENT COSTS ***	79	1.27	1.27	1.27	1.27
SUBSTATIONS					
BUILDINGS	65	1.49	1.47	1.37	1.46
BUILDING RENOVATIONS	20	5.00	5.00	5.00	5.00
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	2.10	1.95	1.67	1.76
POLES AND FIXTURES	45	3.25	3.01	1.99	2.39
POWER TRANSFORMERS	50	2.21	2.44	2.00	2.43
OTHER TRANSFORMERS	50	3.09	2.29	1.86	2.26
INTERRUPTING EQUIPMENT	50	2.41	2.52	2.05	2.31
OTHER STATION EQUIPMENT	45	2.54	2.47	1.98	2.20
ELECTRONIC EQUIPMENT AND BATTERIES	25	4.76	3.81	3.28	3.90
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMER	65	1.68	1.80	1.40	1.52
SYNCHRONOUS CONDENSER OVERHAULS	15	7.43	7.15	5.58	5.58
HVDC CONVERTER EQUIPMENT	30	4.13	3.22	2.47	2.61
HVDC SERIALIZED EQUIPMENT	30	4.18	3.04	2.24	2.07
HVDC ACCESSORY STATION EQUIPMENT	36	2.85	2.98	2.40	2.67
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	25	4.66	3.10	2.49	2.27
DISTRIBUTION					
CONCRETE DUCTLINE AND MANHOLES	75	2.29	2.23	2.09	2.25
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENT	30	2.08	3.66	3.47	3.70
METAL TOWERS	60	1.99	2.10	1.62	1.87
POLES AND FIXTURES	65	2.10	1.96	1.19	1.58
GROUND LINE TREATMENT	12	9.58	7.39	7.39	7.39
OVERHEAD CONDUCTOR AND DEVICES	60	1.98	2.24	1.40	1.80
UNDERGROUND CABLE AND DEVICES - 66 KV	60	1.48	1.72	1.63	2.07
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	1.69	1.70	1.60	1.83
UNDERGROUND CABLE AND DEVICES - SECONDARY	44	2.21	2.27	2.12	2.31
SERIALIZED EQUIPMENT - OVERHEAD	45	2.86	2.28	1.84	2.10
DSC - HIGH VOLTAGE TRANSFORMERS	50	2.19	2.34	2.02	2.34
SERIALIZED EQUIPMENT - UNDERGROUND	42	2.62	2.60	2.13	2.40
ELECTRONIC EQUIPMENT	10	10.00	10.53	10.53	10.53
SERVICES	35	4.38	2.92	1.50	1.89
STREET LIGHTING	45	3.04	2.56	2.02	2.20

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
METERS					
METERS - ELECTRONIC	15	6.10	9.61	9.61	10.52
METERS - ANALOG	26	13.54	3.84	3.84	4.21
METERING EXCHANGES	15	6.67	6.67	6.67	6.67
METERING TRANSFORMERS	50	2.20	1.80	1.80	2.12
COMMUNICATION					
BUILDINGS	65	1.67	1.41	1.30	1.48
BUILDING RENOVATIONS	20	5.67	4.95	4.58	4.58
BUILDING - SYSTEM CONTROL CENTRE	75	1.68	1.39	1.30	1.40
COMMUNICATION TOWERS	60	1.82	1.82	1.71	2.01
FIBRE OPTIC AND METALLIC CABLE	35	3.06	3.12	2.97	3.45
CARRIER EQUIPMENT	20	7.68	4.74	4.34	4.90
OPERATIONAL IT EQUIPMENT	5	22.97	21.00	20.00	20.00
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCIN	8	10.24	18.56	16.64	16.64
OPERATIONAL DATA NETWORK	8	14.10	13.13	12.50	12.50
POWER SYSTEM CONTROL	15	11.16	5.63	5.14	5.50
MOTOR VEHICLES					
PASSENGER VEHICLES	11	11.09	7.03	7.03	7.59
LIGHT TRUCKS	12	7.85	7.16	7.16	7.54
HEAVY TRUCKS	19	5.83	4.68	4.68	5.01
CONSTRUCTION EQUIPMENT	23	5.27	2.77	2.77	3.23
LARGE SOFT-TRACK EQUIPMENT	27	4.28	2.96	2.96	3.79
TRAILERS	35	1.94	2.38	2.38	2.91
MISCELLANEOUS VEHICLES	13	5.93	4.90	4.90	6.60
BUILDINGS					
BUILDINGS - GENERAL	65	1.59	1.65	1.54	1.73
BUILDING RENOVATIONS	20	7.14	5.59	5.00	5.00
BUILDING - 360 PORTAGE - CIVIL	100	1.00	1.00	1.00	1.06
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	2.21	2.23	2.23	2.56
LEASEHOLD IMPROVEMENTS - SONY PLACE	10	10.00	10.00	10.00	10.00
GENERAL EQUIPMENT					
TOOLS, SHOP AND GARAGE EQUIPMENT	15	7.74	6.48	6.48	6.48
COMPUTER EQUIPMENT	5	28.48	20.00	20.00	20.00
OFFICE FURNITURE AND EQUIPMENT	20	4.81	5.00	5.00	5.00
HOT WATER TANKS	6	21.20	16.67	16.67	16.67
EASEMENTS					
EASEMENTS	75	1.28	1.33	1.33	1.33
COMPUTER SOFTWARE AND DEVELOPMENT					
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	11	9.47	8.75	8.75	8.82
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10.00	9.13	9.13	9.13
COMPUTER SOFTWARE - GENERAL	5	19.76	20.00	20.00	20.00
COMPUTER SOFTWARE - COMMUNICATION/OPERATION	5	13.93	27.31	27.31	27.31
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	7	23.35	8.06	8.06	9.33

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous* ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)					
HYDRAULIC GENERATION					
WPLP - DAMS, DYKES AND WEIRS	125		0.91	0.83	0.87
WPLP - POWERHOUSE	125		0.91	0.83	0.87
WPLP - POWERHOUSE RENOVATIONS	40		2.75	2.50	2.50
WPLP - SPILLWAY	80		1.37	1.24	1.46
WPLP - WATER CONTROL SYSTEMS	65		1.68	1.52	1.62
WPLP - ROADS AND SITE IMPROVEMENTS	50		2.19	1.99	2.32
WPLP - TURBINES AND GENERATORS	60		1.84	1.67	1.79
WPLP - GOVERNORS AND EXCITATION SYSTEM	50		2.20	1.99	2.12
WPLP - A/C ELECTRICAL POWER SYSTEMS	55		1.99	1.80	1.91
WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEM	25		4.36	3.93	4.51
WPLP - AUXILIARY STATION PROCESSES	50		2.17	1.97	2.75
WPLP - SUPPORT BUILDINGS	65		1.69	1.53	1.65
WPLP - SUPPORT BUILDING RENOVATIONS	20		5.50	5.00	5.00
WPLP - OPERATIONAL EMPLOYMENT FUND	95		0.97	0.97	0.97
SUBSTATIONS					
WPLP - BUILDINGS	65		1.62	1.54	1.64
WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WOI	50		2.20	1.99	2.13
WPLP - POWER TRANSFORMERS	50		2.28	1.98	3.11
WPLP - INTERRUPTING EQUIPMENT	50		2.29	1.98	2.54
WPLP - OTHER STATION EQUIPMENT	45		2.55	2.20	2.56
WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	25		4.33	3.90	5.23
COMMUNICATION					
WPLP - FIBRE OPTIC AND METALLIC CABLE	35		2.95	2.83	3.57
WPLP - CARRIER EQUIPMENT	20		4.98	4.71	5.88
MOTOR VEHICLES					
WPLP - HEAVY TRUCKS	19		2.43	2.43	2.75
WPLP - CONSTRUCTION EQUIPMENT	23		3.61	3.61	4.44
WPLP - TRAILERS	35		2.45	2.45	3.12
WPLP - MISCELLANEOUS VEHICLES	13		6.38	6.38	9.42
GENERAL EQUIPMENT					
WPLP - COMPUTER EQUIPMENT	5		15.66	15.66	15.66

* Depreciation rates were not established in the 2010 Depreciation Study

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous* ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
WPLP INTANGIBLE ASSETS					
TRANSMISSION					
WPLP - ROADS, TRAILS AND BRIDGES	50		2.18	1.98	2.20
WPLP - METAL TOWERS AND CONCRETE POLES	85		1.47	1.17	1.24
WPLP - POLES AND FIXTURES	55		2.45	1.80	2.10
WPLP - OVERHEAD CONDUCTOR AND DEVICES	80		1.43	1.24	1.32
WPLP - TRANSMISSION DEVELOPMENT FUND	79		1.26	1.26	1.26
SUBSTATIONS					
WPLP - BUILDINGS	65		1.62	1.54	1.64
WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WOI	50		2.20	1.99	2.13
WPLP - POWER TRANSFORMERS	50		2.28	1.98	3.12
WPLP - OTHER TRANSFORMERS	50		2.27	1.96	2.52
WPLP - INTERRUPTING EQUIPMENT	50		2.29	1.98	2.54
WPLP - OTHER STATION EQUIPMENT	45		2.55	2.20	2.57
WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	25		4.33	3.90	5.23
DISTRIBUTION					
WPLP - POLES AND FIXTURES	65		2.12	1.52	2.20
WPLP - OVERHEAD CONDUCTOR AND DEVICES	60		2.30	1.65	2.65
WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY	60		1.75	1.67	1.94
WPLP - SERIALIZED EQUIPMENT - UNDERGROUND	42		2.73	2.36	2.75
COMMUNICATION					
WPLP - FIBRE OPTIC AND METALLIC CABLE	35		2.95	2.83	3.57
WPLP - CARRIER EQUIPMENT	20		4.98	4.71	5.88
WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCIN	8		13.62	12.85	12.85
WPLP - OPERATIONAL DATA NETWORK	8		12.66	11.89	11.89
EASEMENTS	75		1.33	1.33	1.33

* Depreciation rates were not established in the 2010 Depreciation Study

Depreciation Rate Schedules (Electric operations)

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
HYDRAULIC GENERATION				
GREAT FALLS				
DAMS, DYKES AND WEIRS	125	1.28	1.32	1.12
POWERHOUSE	125	1.27	1.28	1.07
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.59	1.50	1.35
WATER CONTROL SYSTEMS	65	2.07	1.52	1.35
ROADS AND SITE IMPROVEMENTS	50	2.33	2.42	2.42
TURBINES AND GENERATORS	60	1.82	2.25	2.03
GOVERNORS AND EXCITATION SYSTEM	50	2.11	2.25	2.06
LICENCE RENEWAL	50	2.00	2.04	2.04
A/C ELECTRICAL POWER SYSTEMS	55	2.10	1.84	1.67
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.43	3.86	3.79
AUXILIARY STATION PROCESSES	50	2.59	2.03	2.10
SUPPORT BUILDINGS	65	1.73	1.69	1.36
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
POINTE DU BOIS - Original				
DAMS, DYKES AND WEIRS	125	3.63	3.10	2.70
POWERHOUSE	125	4.39	2.94	2.55
POWERHOUSE RENOVATIONS	40	5.24	4.10	3.71
SPILLWAY	80	10.76	84.53	73.37
WATER CONTROL SYSTEMS	65	3.35	2.11	1.73
ROADS AND SITE IMPROVEMENTS	50	3.36	4.09	3.80
TURBINES AND GENERATORS	60	4.04	2.84	2.44
GOVERNORS AND EXCITATION SYSTEM	50	5.24	4.02	3.68
LICENCE RENEWAL	50	4.76	3.85	3.85
A/C ELECTRICAL POWER SYSTEMS	55	4.58	3.16	2.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.12	4.30	4.26
AUXILIARY STATION PROCESSES	50	4.03	3.71	3.59
SUPPORT BUILDINGS	65	2.93	2.99	2.59
SUPPORT BUILDING RENOVATIONS	20	5.50	4.47	3.84
POINTE DU BOIS - New				
DAMS, DYKES AND WEIRS	125	-	0.91	0.85
SPILLWAY	80	1.47	1.37	1.49
WATER CONTROL SYSTEMS	65	-	1.69	1.64
ROADS AND SITE IMPROVEMENTS	50	-	2.20	2.36
A/C ELECTRICAL POWER SYSTEMS	55	-	2.40	1.94
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	-	4.40	4.54
AUXILIARY STATION PROCESSES	50	-	2.20	3.01
SUPPORT BUILDINGS	65	-	1.69	1.65
SUPPORT BUILDING RENOVATIONS	20	-	5.50	5.00
SEVEN SISTERS				
DAMS, DYKES AND WEIRS	125	1.03	1.06	0.90
POWERHOUSE	125	0.90	0.91	0.74
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.17	1.36	1.17
WATER CONTROL SYSTEMS	65	1.80	1.25	1.02
ROADS AND SITE IMPROVEMENTS	50	1.84	1.78	1.30
TURBINES AND GENERATORS	60	1.64	1.84	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.00	2.22	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.91	1.74	1.56
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	3.73	3.80	3.44
AUXILIARY STATION PROCESSES	50	2.13	1.91	2.03
SUPPORT BUILDINGS	65	1.74	1.65	1.52
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
SLAVE FALLS				
DAMS, DYKES AND WEIRS	125	1.69	1.71	1.54
POWERHOUSE	125	1.58	1.59	1.43
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.87	1.82	1.74
WATER CONTROL SYSTEMS	65	2.18	1.77	1.65
ROADS AND SITE IMPROVEMENTS	50	2.20	2.30	2.36
TURBINES AND GENERATORS	60	1.79	1.91	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.22	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	2.00	1.91
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.72	4.42	4.56
AUXILIARY STATION PROCESSES	50	2.73	2.34	2.70
SUPPORT BUILDINGS	65	1.81	2.01	1.89
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
PINE FALLS				
DAMS, DYKES AND WEIRS	125	1.17	1.23	1.12
POWERHOUSE	125	0.83	0.83	0.71
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.60	1.50	1.49
WATER CONTROL SYSTEMS	65	1.95	1.28	1.06
ROADS AND SITE IMPROVEMENTS	50	1.81	1.68	1.61
TURBINES AND GENERATORS	60	1.47	1.62	1.37
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.06	1.83	1.58
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.25	4.17	4.04
AUXILIARY STATION PROCESSES	50	2.54	1.78	1.81
SUPPORT BUILDINGS	65	1.61	1.62	1.56
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
COMMUNITY DEVELOPMENT COSTS	78	1.17	1.28	1.28
MCARTHUR FALLS				
DAMS, DYKES AND WEIRS	125	0.91	1.12	1.00
POWERHOUSE	125	0.83	0.84	0.72
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.19	1.19	0.97
WATER CONTROL SYSTEMS	65	2.06	1.37	1.25
ROADS AND SITE IMPROVEMENTS	50	1.99	1.94	1.71
TURBINES AND GENERATORS	60	1.06	1.35	0.94
GOVERNORS AND EXCITATION SYSTEM	50	2.10	2.08	1.94
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.90	1.72	1.32
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.29	3.62	2.74
AUXILIARY STATION PROCESSES	50	2.58	1.82	1.85
SUPPORT BUILDINGS	65	1.63	1.73	1.67
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
KELSEY				
DAMS, DYKES AND WEIRS	125	1.05	1.13	1.03
POWERHOUSE	125	0.89	1.18	1.08
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.34	1.71	1.58
WATER CONTROL SYSTEMS	65	2.09	1.70	1.61
ROADS AND SITE IMPROVEMENTS	50	2.05	2.44	2.30
TURBINES AND GENERATORS	60	1.68	1.90	1.85
GOVERNORS AND EXCITATION SYSTEM	50	2.14	2.25	2.17
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.03	2.11	2.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.67	4.62
AUXILIARY STATION PROCESSES	50	2.63	2.19	2.31
SUPPORT BUILDINGS	65	1.67	1.79	1.73
SUPPORT BUILDING RENOVATIONS	20	4.98	4.98	4.44
GRAND RAPIDS				
DAMS, DYKES AND WEIRS	125	0.98	1.01	0.90
POWERHOUSE	125	0.91	0.92	0.81
POWERHOUSE RENOVATIONS	40	4.40	2.55	2.28
SPILLWAY	80	1.30	1.28	1.15
WATER CONTROL SYSTEMS	65	1.79	1.10	0.99
ROADS AND SITE IMPROVEMENTS	50	1.68	1.63	1.21
TURBINES AND GENERATORS	60	1.64	1.82	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.13	2.21	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.07	1.84	1.66
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.08	3.90	2.49
AUXILIARY STATION PROCESSES	50	2.62	2.02	2.29
SUPPORT BUILDINGS	65	1.66	1.69	1.60
SUPPORT BUILDING RENOVATIONS	20	5.50	5.67	5.00
COMMUNITY DEVELOPMENT COSTS ***	79	1.16	1.21	1.21
KETTLE				
DAMS, DYKES AND WEIRS	125	0.86	0.86	0.78
POWERHOUSE	125	0.87	0.86	0.79
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.33	1.26	1.16
WATER CONTROL SYSTEMS	65	1.55	0.99	0.89
ROADS AND SITE IMPROVEMENTS	50	2.14	2.20	2.31
TURBINES AND GENERATORS	60	1.48	1.90	1.73
GOVERNORS AND EXCITATION SYSTEM	50	1.66	2.14	1.92
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.04	2.04	1.96
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.11	4.20	3.37
AUXILIARY STATION PROCESSES	50	2.44	1.82	1.86
SUPPORT BUILDINGS	65	1.46	1.75	1.70
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
LAURIE RIVER				
DAMS, DYKES AND WEIRS	125	3.47	3.20	2.70
POWERHOUSE	125	4.25	3.89	3.40
POWERHOUSE RENOVATIONS	40	5.00	5.24	4.76
SPILLWAY	80	3.88	3.44	2.96
WATER CONTROL SYSTEMS	65	3.84	3.52	3.03
ROADS AND SITE IMPROVEMENTS	50	4.01	3.69	3.23
TURBINES AND GENERATORS	60	4.49	4.11	3.62
GOVERNORS AND EXCITATION SYSTEM	50	4.70	4.29	3.81
LICENCE RENEWAL	50	4.55	4.76	4.76
A/C ELECTRICAL POWER SYSTEMS	55	4.08	3.63	3.15
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	7.23	6.28	5.15
AUXILIARY STATION PROCESSES	50	4.30	3.73	3.31
SUPPORT BUILDINGS	65	3.75	3.36	2.87
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
JENPEG				
DAMS, DYKES AND WEIRS	125	0.92	0.91	0.84
POWERHOUSE	125	0.89	0.90	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.48
SPILLWAY	80	1.42	1.35	1.28
WATER CONTROL SYSTEMS	65	2.02	1.24	1.07
ROADS AND SITE IMPROVEMENTS	50	2.12	2.07	1.87
TURBINES AND GENERATORS	60	1.63	1.89	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.05	1.81	1.53
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.53	4.15	3.39
AUXILIARY STATION PROCESSES	50	2.66	1.92	2.06
SUPPORT BUILDINGS	65	1.67	1.69	1.61
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
LAKE WINNIPEG REGULATION				
DAMS, DYKES AND WEIRS	125	0.82	0.82	0.77
LICENCE RENEWAL	50	2.00	2.02	2.02
COMMUNITY DEVELOPMENT COSTS	85	0.94	1.18	1.18
CHURCHILL RIVER DIVERSION				
DAMS, DYKES AND WEIRS	125	0.88	0.88	0.83
SPILLWAY	80	1.47	1.39	1.32
WATER CONTROL SYSTEMS	65	2.21	1.17	1.00
ROADS AND SITE IMPROVEMENTS	50	2.21	2.11	1.78
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	1.88	1.57
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.82	4.78	2.36
AUXILIARY STATION PROCESSES	50	2.75	1.97	2.11
SUPPORT BUILDINGS	65	1.69	1.71	1.66
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
COMMUNITY DEVELOPMENT COSTS	90	0.93	1.07	1.07

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
LONG SPRUCE				
DAMS, DYKES AND WEIRS	125	0.90	0.90	0.83
POWERHOUSE	125	0.90	0.90	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.43	1.36	1.30
WATER CONTROL SYSTEMS	65	2.04	0.99	0.78
ROADS AND SITE IMPROVEMENTS	50	2.10	2.07	1.87
TURBINES AND GENERATORS	60	1.63	1.88	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.19	2.18	2.08
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.09	1.79	1.51
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.37	4.37	3.87
AUXILIARY STATION PROCESSES	50	2.63	1.60	1.53
SUPPORT BUILDINGS	65	1.69	1.69	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.90
LIMESTONE				
DAMS, DYKES AND WEIRS	125	0.90	0.91	0.85
POWERHOUSE	125	0.91	0.91	0.85
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.45	1.37	1.37
WATER CONTROL SYSTEMS	65	2.17	1.39	1.28
ROADS AND SITE IMPROVEMENTS	50	2.17	2.14	2.03
TURBINES AND GENERATORS	60	1.68	1.90	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.17	2.15	1.96
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.17	1.89	1.73
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.67	4.16	3.48
AUXILIARY STATION PROCESSES	50	2.71	1.78	1.80
SUPPORT BUILDINGS	65	1.68	1.71	1.63
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.89
WUSKWATIM				
DAMS, DYKES AND WEIRS	125	0.88	0.91	0.87
POWERHOUSE	125	0.88	0.91	0.87
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.47	1.36	1.46
WATER CONTROL SYSTEMS	65	2.20	1.68	1.62
ROADS AND SITE IMPROVEMENTS	50	2.20	2.19	2.32
TURBINES AND GENERATORS	60	1.69	1.83	1.78
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.19	2.12
A/C ELECTRICAL POWER SYSTEMS	55	2.20	1.99	1.92
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.78	4.24	4.39
AUXILIARY STATION PROCESSES	50	2.75	2.13	2.93
SUPPORT BUILDINGS	65	1.69	1.69	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
INFRASTRUCTURE SUPPORTING GENERATION				
PROVINCIAL ROADS	50	2.30	2.49	2.21
TOWN SITE BUILDING	55	1.71	2.12	2.03
TOWN SITE BUILDINGS RENOVATIONS	20	5.94	5.30	5.00
TOWN SITE OTHER INFRASTRUCTURE	45	2.49	3.11	2.93

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
THERMAL GENERATION				
BRANDON UNIT 5 (COAL)				
POWERHOUSE	75	3.87	4.52	4.50
POWERHOUSE RENOVATIONS	40	10.00	15.88	15.88
ROADS AND SITE IMPROVEMENTS	50	4.56	5.37	5.36
THERMAL TURBINES AND GENERATORS	60	5.03	5.73	5.72
GOVERNORS AND EXCITATION SYSTEM	50	5.07	5.51	5.52
STEAM GENERATOR AND AUXILIARIES	60	3.93	4.06	4.05
LICENCE RENEWAL	50	10.00	14.81	14.81
A/C ELECTRICAL POWER SYSTEMS	55	4.06	4.65	4.64
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.41	4.44	4.41
AUXILIARY STATION PROCESSES	50	4.67	5.36	5.37
SUPPORT BUILDINGS	65	4.25	5.97	5.97
SUPPORT BUILDING RENOVATIONS	20	10.00	16.67	16.67
BRANDON UNITS 6 AND 7				
POWERHOUSE	75	1.65	1.38	1.26
POWERHOUSE RENOVATIONS	40	4.40	2.72	2.46
THERMAL TURBINES AND GENERATORS	60	2.12	1.70	1.64
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
COMBUSTION TURBINE	25	4.05	3.87	3.66
LICENCE RENEWAL	50	2.00	2.00	2.00
COMBUSTION TURBINE OVERHAULS	15	11.00	7.33	6.67
A/C ELECTRICAL POWER SYSTEMS	55	2.12	1.88	1.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.52	4.63
AUXILIARY STATION PROCESSES	50	2.64	1.91	2.10
SELKIRK				
POWERHOUSE	75	0.93	0.76	0.79
POWERHOUSE RENOVATIONS	40	4.00	2.45	2.45
ROADS AND SITE IMPROVEMENTS	50	1.35	1.34	1.42
THERMAL TURBINES AND GENERATORS	60	1.46	1.09	1.18
GOVERNORS AND EXCITATION SYSTEM	50	2.00	1.13	1.30
STEAM GENERATOR AND AUXILIARIES	60	1.34	1.49	1.66
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.21	1.06	1.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	2.41	2.11	2.40
AUXILIARY STATION PROCESSES	50	1.64	1.19	1.44
SUPPORT BUILDINGS	65	1.06	1.06	1.13
SUPPORT BUILDING RENOVATIONS	20	5.00	5.00	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
DIESEL GENERATION				
BUILDINGS	25	2.57	3.15	3.17
BUILDING RENOVATIONS	15	5.14	6.67	6.67
ENGINES AND GENERATORS - OVERHAULS	4	20.00	25.00	25.00
ENGINES AND GENERATORS	22	1.88	2.24	2.73
ACCESSORY STATION EQUIPMENT	20	3.07	3.70	3.67
FUEL STORAGE AND HANDLING	25	2.28	2.37	2.60
TRANSMISSION				
ROADS, TRAILS AND BRIDGES	50	2.51	2.19	2.18
METAL TOWERS AND CONCRETE POLES	85	1.51	1.54	1.23
POLES AND FIXTURES	55	2.49	2.48	1.80
GROUND LINE TREATMENT	10	10.00	10.00	10.00
OVERHEAD CONDUCTOR AND DEVICES	80	1.62	1.27	1.10
UNDERGROUND CABLE AND DEVICES	45	2.23	1.96	1.81
COMMUNITY DEVELOPMENT COSTS ***	79	1.27	1.27	1.27
SUBSTATIONS				
BUILDINGS	65	1.49	1.47	1.46
BUILDING RENOVATIONS	20	5.00	5.00	5.00
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	2.10	1.95	1.76
POLES AND FIXTURES	45	3.25	3.01	2.39
POWER TRANSFORMERS	50	2.21	2.44	2.43
OTHER TRANSFORMERS	50	3.09	2.29	2.26
INTERRUPTING EQUIPMENT	50	2.41	2.52	2.31
OTHER STATION EQUIPMENT	45	2.54	2.47	2.20
ELECTRONIC EQUIPMENT AND BATTERIES	25	4.76	3.81	3.90
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	65	1.68	1.80	1.52
SYNCHRONOUS CONDENSER OVERHAULS	15	7.43	7.15	5.58
HVDC CONVERTER EQUIPMENT	30	4.13	3.22	2.61
HVDC SERIALIZED EQUIPMENT	30	4.18	3.04	2.07
HVDC ACCESSORY STATION EQUIPMENT	36	2.85	2.98	2.67
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	25	4.66	3.10	2.27
DISTRIBUTION				
CONCRETE DUCTLINE AND MANHOLES	75	2.29	2.23	2.25
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENTS	30	2.08	3.66	3.70
METAL TOWERS	60	1.99	2.10	1.87
POLES AND FIXTURES	65	2.10	1.96	1.58
GROUND LINE TREATMENT	12	9.58	7.39	7.39
OVERHEAD CONDUCTOR AND DEVICES	60	1.98	2.24	1.80
UNDERGROUND CABLE AND DEVICES - 66 KV	60	1.48	1.72	2.07
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	1.69	1.70	1.83
UNDERGROUND CABLE AND DEVICES - SECONDARY	44	2.21	2.27	2.31
SERIALIZED EQUIPMENT - OVERHEAD	45	2.86	2.28	2.10
DSC - HIGH VOLTAGE TRANSFORMERS	50	2.19	2.34	2.34
SERIALIZED EQUIPMENT - UNDERGROUND	42	2.62	2.60	2.40
ELECTRONIC EQUIPMENT	10	10.00	10.53	10.53
SERVICES	35	4.38	2.92	1.89
STREET LIGHTING	45	3.04	2.56	2.20

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
METERS				
METERS - ELECTRONIC	15	6.10	9.61	10.52
METERS - ANALOG	26	13.54	3.84	4.21
METERING EXCHANGES	15	6.67	6.67	6.67
METERING TRANSFORMERS	50	2.20	1.80	2.12
COMMUNICATION				
BUILDINGS	65	1.67	1.41	1.48
BUILDING RENOVATIONS	20	5.67	4.95	4.58
BUILDING - SYSTEM CONTROL CENTRE	75	1.68	1.39	1.40
COMMUNICATION TOWERS	60	1.82	1.82	2.01
FIBRE OPTIC AND METALLIC CABLE	35	3.06	3.12	3.45
CARRIER EQUIPMENT	20	7.68	4.74	4.90
OPERATIONAL IT EQUIPMENT	5	22.97	21.00	20.00
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8	10.24	18.56	16.64
OPERATIONAL DATA NETWORK	8	14.10	13.13	12.50
POWER SYSTEM CONTROL	15	11.16	5.63	5.50
MOTOR VEHICLES				
PASSENGER VEHICLES	11	11.09	7.03	7.59
LIGHT TRUCKS	12	7.85	7.16	7.54
HEAVY TRUCKS	19	5.83	4.68	5.01
CONSTRUCTION EQUIPMENT	23	5.27	2.77	3.23
LARGE SOFT-TRACK EQUIPMENT	27	4.28	2.96	3.79
TRAILERS	35	1.94	2.38	2.91
MISCELLANEOUS VEHICLES	13	5.93	4.90	6.60
BUILDINGS				
BUILDINGS - GENERAL	65	1.59	1.65	1.73
BUILDING RENOVATIONS	20	7.14	5.59	5.00
BUILDING - 360 PORTAGE - CIVIL	100	1.00	1.00	1.06
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	2.21	2.23	2.56
LEASEHOLD IMPROVEMENTS - SONY PLACE	10	10.00	10.00	10.00
GENERAL EQUIPMENT				
TOOLS, SHOP AND GARAGE EQUIPMENT	15	7.74	6.48	6.48
COMPUTER EQUIPMENT	5	28.48	20.00	20.00
OFFICE FURNITURE AND EQUIPMENT	20	4.81	5.00	5.00
HOT WATER TANKS	6	21.20	16.67	16.67
EASEMENTS				
EASEMENTS	75	1.28	1.33	1.33
COMPUTER SOFTWARE AND DEVELOPMENT				
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	11	9.47	8.75	8.82
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10.00	9.13	9.13
COMPUTER SOFTWARE - GENERAL	5	19.76	20.00	20.00
COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	5	13.93	27.31	27.31
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	7	23.35	8.06	9.33

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE		PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP	
					AMOUNT	PERCENT			
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)	
	COMMUNICATION								
5000B	BUILDINGS	6,955,504	2,165,736	2,947,372	(781,636)	(36.09)	46.9	(16,666)	
5000C	BUILDING RENOVATIONS	3,486,352	1,243,551	1,440,484	(196,933)	(15.84)	13.6	(14,480)	
5000D	BUILDING - SYSTEM CONTROL CENTRE	15,857,686	3,263,340	3,525,976	(262,636)	(8.05)	59.6	(4,407)	
5000G	COMMUNICATION TOWERS	12,362,119	3,538,441	3,350,680	187,761	5.31	42.6	4,408	
5000H	FIBRE OPTIC AND METALLIC CABLE	131,559,381	32,888,279	29,139,100	3,749,179	11.40	26.2	143,098	
5000J	CARRIER EQUIPMENT	125,921,733	51,244,346	61,816,520	(10,572,174)	(20.63)	12.7	(832,455)	
5000K	OPERATIONAL IT EQUIPMENT	4,821,768	2,484,791	2,691,962	(207,171)	(8.34)	2.7		**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8,862,073	5,464,791	4,438,690	1,026,101	18.78	2.8	366,465	
5000N	OPERATIONAL DATA NETWORK	18,817,356	7,986,904	8,136,535	(149,631)	(1.87)	4.7		**
5000R	POWER SYSTEM CONTROL	14,264,753	6,390,903	8,431,858	(2,040,955)	(31.94)	11.1	(183,870)	
	TOTAL COMMUNICATION	**342,908,725**	**116,671,082**	**125,919,176**	**(9,248,094)**	**(7.93)**		**(537,907)**	
	MOTOR VEHICLES								
6000E	PASSENGER VEHICLES	1,145,330	471,876	487,352	(15,476)	(3.28)	5.5	(2,814)	
6000F	LIGHT TRUCKS	69,461,644	28,139,845	29,754,753	(1,614,908)	(5.74)	6.9	(234,045)	
6000G	HEAVY TRUCKS	73,416,587	27,603,941	29,435,263	(1,831,322)	(6.63)	11.6	(157,873)	
6000H	CONSTRUCTION EQUIPMENT	21,130,532	5,649,098	8,256,831	(2,607,733)	(46.16)	17.4	(149,870)	
6000I	LARGE SOFT-TRACK EQUIPMENT	15,620,474	3,468,440	4,072,604	(604,164)	(17.42)	20.6	(29,328)	
6000J	TRAILERS	18,887,911	4,304,614	4,536,914	(232,300)	(5.40)	25.8	(9,004)	
6000K	MISCELLANEOUS VEHICLES	6,114,461	1,529,829	2,553,455	(1,023,626)	(66.91)	10.2	(100,356)	
	TOTAL MOTOR VEHICLES	**205,776,939**	**71,167,643**	**79,097,171**	**(7,929,528)**	**(11.14)**		**(683,288)**	
	BUILDINGS								
8000B	BUILDINGS - GENERAL	103,251,540	29,602,068	29,525,141	76,928	0.26	46.3	1,662	
8000C	BUILDING RENOVATIONS	37,401,024	12,021,426	10,936,091	1,085,335	9.03	13.3		**
8000D	BUILDING - 360 PORTAGE - CIVIL	202,792,903	10,946,359	10,816,316	130,043	1.19	94.6	1,375	
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	77,339,398	8,759,755	8,539,762	219,993	2.51	39.9	5,514	
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE	1,007,453	631,159	617,462	13,698	2.17	3.7		**
	TOTAL BUILDINGS	**421,792,317**	**61,960,767**	**60,434,771**	**1,525,996**	**2.46**		**8,550**	
	GENERAL EQUIPMENT								
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT	87,537,592	42,845,748	39,778,073	3,067,676	7.16	7.3		**
9000K	COMPUTER EQUIPMENT	49,555,418	23,823,338	25,481,868	(1,658,530)	(6.96)	3.0		**
9000L	OFFICE FURNITURE AND EQUIPMENT	26,318,137	9,159,013	9,724,793	(565,780)	(6.18)	13.3		**
9000M	HOT WATER TANKS	881,848	643,731	636,218	7,513	1.17	1.9		**
	TOTAL GENERAL EQUIPMENT	**164,292,994**	**76,471,830**	**75,620,951**	**850,879**	**1.11**		**0**	
	EASEMENTS								
A100A	EASEMENTS	66,021,103	12,551,916	12,901,908	(349,992)	(2.79)	60.8		**
	TOTAL EASEMENTS	**66,021,103**	**12,551,916**	**12,901,908**	**(349,992)**	**(2.79)**		**0**	
	COMPUTER SOFTWARE AND DEVELOPMENT								
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS	111,692,382	67,182,098	68,946,077	(1,763,979)	(2.63)	4.7	(375,315)	
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS	48,787,249	23,415,498	26,099,591	(2,684,093)	(11.46)	6.3	(426,046)	
A200J	COMPUTER SOFTWARE - GENERAL	6,701,454	3,603,877	3,490,469	113,409	3.15	2.5	0	**
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	4,652,481	2,407,134	1,659,404	747,730	31.06	2.2	339,877	
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	10,313,958	3,036,286	6,634,595	(3,598,309)	(118.51)	5.6	(642,555)	
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT	**182,147,524**	**99,644,893**	**106,830,136**	**(7,185,243)**	**(7.21)**		**(1,104,039)**	
	TOTAL MANITOBA HYDRO	**14,230,425,552**	**4,366,181,882**	**5,381,231,843**	**(1,015,049,961)**			**(29,017,007)**	

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** True-up excluded as exisiting assets in account are fully depreciated.

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c) The following table identifies the change in depreciation for the forecasted balance of the plant groups for the years in which the Bipole III and Keeyask plant are fully in-service. The Bipole III plant is forecast to go in service in July 2018 so a comparison is made for the following 2019/20 fiscal year. The last unit for the Keeyask plant is forecast to go in service in August 2022 so a comparison is made for the following 2023/24 fiscal year.

PUB/MH-II-2c
MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
(in thousands)

	ELG	CGAAP ASL		ELG	CGAAP ASL	
	2019/20	2019/20	2019/20	2023/24	2023/24	2023/24
	Forecast	Forecast	Difference	Forecast	Forecast	Difference
PROPERTY, PLANT & EQUIPMENT						
Generation						
Hydraulic Generating Stations	122 806	114 132	8 673	246 115	226 890	19 226
Thermal Generating Stations	15 923	14 967	956	17 094	16 081	1 013
Diesel Generating Stations	2 041	1 777	264	4 300	3 820	480
	140 769	130 876	9 894	267 510	246 790	20 719
Transmission						
Transmission	41 129	38 195	2 934	50 072	46 397	3 675
	41 129	38 195	2 934	50 072	46 397	3 675
Stations						
Substations	162 625	149 165	13 459	176 057	161 325	14 732
Transformers	1 804	1 748	55	1 681	1 632	50
	164 428	150 914	13 515	177 739	162 957	14 782
Distribution						
Subtransmission Lines	8 435	6 777	1 659	10 680	8 678	2 002
Distribution Lines	71 029	60 521	10 507	86 140	73 562	12 578
Meters & Transformers	6 220	5 865	356	6 557	6 144	413
	85 684	73 163	12 522	103 377	88 384	14 993
Other						
Communications	24 807	22 788	2 019	23 096	20 955	2 141
Motor Vehicles	14 672	13 406	1 266	16 129	14 695	1 434
Structures & Improvements	10 481	9 799	682	11 308	10 533	775
General Equipment	18 140	18 140	-	18 351	18 351	-
Miscellaneous	(7 047)	(6 785)	(261)	(7 665)	(7 246)	(419)
Corporate Allocation	(1 372)	(1 372)	-	(1 003)	(1 003)	-
	59 681	55 976	3 705	60 215	56 285	3 931
Total Depreciation on PP & E	491 693	449 124	42 569	658 913	600 812	58 101
INTANGIBLES						
Computer Development	21 480	21 181	300	24 880	24 549	331
Easements	2 231	2 231	0	2 660	2 659	0
Transmission Rights	-	-	-	27 762	27 762	-
Total Amortization on Intangibles	23 711	23 412	300	55 301	54 971	331
Loss on Disposition	-	-		-	-	
Total Loss on Disposition	-	-		-	-	
Total Depreciation & Amortization Expense	**515 404**	**472 535**	**42 869**	**714 214**	**655 783**	**58 431**

In addition, the table below identifies the forecast depreciation expense for each of the Bipole III and Keeyask plant assets:

	FORECAST DEPRECIATION EXPENSE ELG NO SALVAGE (IFRS) 2019/20 $ 000'S	FORECAST DEPRECIATION EXPENSE CGAAP ASL NO SALVAGE 2019/20 $ 000'S	FORECAST DEPRECIATION EXPENSE ELG NO SALVAGE (IFRS) 2023/24 $ 000'S	FORECAST DEPRECIATION EXPENSE CGAAP ASL NO SALVAGE 2023/24 $ 000'S
BIPOLE III				
Transmission	25 766	23 954		
Substations	64 859	60 438		
Communications	3 894	3 565		
General Equipment	714	714		
Motor Vehicles	1 216	1 113		
Other	701	701		
Total	**97 151**	**90 486**		
KEEYASK PLANT				
Generation			116 159	105 985
Transmission			2 180	1 888
Substations			2 341	2 028
Distribution			275	238
Total			**120 955**	**110 138**

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TABLE 3: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL DEBIT BALANCE

in thousands of dollars

	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of regulatory deferral debit balance											
Power Smart programs	$ 188 873	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361
Change in depreciation method	59 441	90 827	124 778	164 284	200 716	236 074	272 464	314 894	298 439	280 577	262 716
Deferred ineligible overhead	40 400	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938
Loss on disposal of assets	8 339	9 641	9 352	8 775	8 198	7 622	7 045	6 468	5 891	5 314	4 737
Site restoration costs	30 710	28 001	26 689	25 401	22 954	20 712	18 855	16 232	13 998	11 828	9 837
Regulatory costs	3 821	5 409	6 131	4 805	3 260	2 648	2 155	2 709	2 496	2 841	2 620
Acquisition costs	10 480	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560
Affordable Energy Fund	4 324	4 163	3 714	3 234	2 670	2 126	1 615	1 126	672	350	203
Conawapa Generation	-	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294
DSM deferral	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	389 987	461 617	533 425	646 965	1 111 433	1 182 497	1 246 148	1 288 788	1 241 241	1 191 690	1 143 065
Additions to regulatory deferral debit balance											
Power Smart programs	$ 50 453	$ 57 184	$ 99 404	$ 94 251	$ 88 857	$ 86 929	$ 66 549	$ 60 271	$ 62 350	$ 66 576	$ 70 722
Change in depreciation method	31 386	33 952	39 506	42 869	44 702	47 924	56 279	-	-	-	-
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-	-
Loss on disposal of assets	1 302	-	-	-	-	-	-	-	-	-	-
Site restoration costs	1 361	2 794	2 703	1 408	1 317	1 133	6	-	-	-	-
Regulatory costs	3 946	3 664	2 339	1 339	1 882	1 391	1 954	1 444	2 029	1 499	2 114
Acquisition costs	-	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	63	-	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	379 758	-	-	-	-	-	-	-
DSM deferral	5 200	-	-	-	-	-	-	-	-	-	-
	113 912	117 794	164 151	539 825	156 958	157 576	144 988	61 715	64 379	68 075	72 836
Amortization of regulatory deferral debit balance											
Power Smart programs	$ (34 937)	$ (35 742)	$ (36 662)	$ (43 202)	$ (49 473)	$ (55 519)	$ (61 480)	$ (65 459)	$ (68 888)	$ (71 976)	$ (73 251)
Change in depreciation method	-	-	-	(6 437)	(9 345)	(11 534)	(13 850)	(16 455)	(17 862)	(17 862)	(17 862)
Deferred ineligible overhead	-	(1 768)	(4 545)	(5 555)	(6 565)	(7 575)	(8 585)	(9 090)	(9 090)	(9 090)	(9 090)
Loss on disposal of assets	-	(288)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)
Site restoration costs	(4 070)	(4 106)	(3 990)	(3 855)	(3 559)	(2 990)	(2 629)	(2 234)	(2 170)	(1 991)	(1 826)
Regulatory costs	(2 358)	(2 942)	(3 665)	(2 884)	(2 495)	(1 883)	(1 400)	(1 657)	(1 684)	(1 721)	(1 749)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)
Affordable Energy Fund	(224)	(449)	(480)	(563)	(545)	(511)	(489)	(454)	(322)	(147)	(97)
Conawapa Generation	-	-	-	(11 592)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	(42 281)	(45 987)	(50 612)	(75 357)	(85 894)	(93 926)	(102 347)	(109 263)	(113 930)	(116 700)	(117 790)
Closing balance of regulatory deferral debit balance											
Power Smart programs	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361	$ 395 831
Change in depreciation method	90 827	124 778	164 284	200 716	236 074	272 464	314 894	298 439	280 577	262 716	244 854
Deferred ineligible overhead	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938	110 848
Loss on disposal of assets	9 641	9 352	8 775	8 198	7 622	7 045	6 468	5 891	5 314	4 737	4 160
Site restoration costs	28 001	26 689	25 401	22 954	20 712	18 855	16 232	13 998	11 828	9 837	8 011
Regulatory costs	5 409	6 131	4 805	3 260	2 648	2 155	2 709	2 496	2 841	2 620	2 985
Acquisition costs	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560	2 868
Affordable Energy Fund	4 163	3 714	3 234	2 670	2 126	1 615	1 126	672	350	203	106
Conawapa Generation	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294	279 649
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	461 617	**533 425**	**646 965**	**1 111 433**	**1 182 497**	**1 246 148**	**1 288 788**	**1 241 241**	**1 191 690**	**1 143 065**	**1 098 110**

TABLE 3: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL DEBIT BALANCE

in thousands of dollars

	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of regulatory deferral debit balance									
Power Smart programs	$ 395 831	$ 395 200	$ 397 041	$ 404 833	$ 413 227	$ 423 916	$ 436 640	$ 449 200	$ 460 818
Change in depreciation method	244 854	226 992	209 130	191 269	173 407	155 545	137 684	119 822	101 960
Deferred ineligible overhead	110 848	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128
Loss on disposal of assets	4 160	3 583	3 006	2 429	1 852	1 275	698	121	(456)
Site restoration costs	8 011	6 286	4 773	3 439	2 393	1 502	885	452	157
Regulatory costs	2 985	2 760	3 145	2 911	3 313	3 070	3 489	3 235	3 672
Acquisition costs	2 868	2 176	1 484	806	506	206	7	1	1
Affordable Energy Fund	106	11	11	11	11	11	11	11	11
Conawapa Generation	279 649	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	1 098 110	1 054 570	1 014 416	979 788	947 064	916 145	888 298	859 990	831 577
Additions to regulatory deferral debit balance									
Power Smart programs	$ 74 678	$ 78 900	$ 82 801	$ 82 257	$ 83 893	$ 85 623	$ 87 367	$ 89 135	$ 90 933
Change in depreciation method	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-
Regulatory costs	1 564	2 206	1 632	2 302	1 703	2 402	1 777	2 506	1 854
Acquisition costs	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	-	-	-	-	-	-
DSM deferral	-	-	-	-	-	-	-	-	-
	76 243	81 106	84 433	84 558	85 596	88 025	89 144	91 640	92 787
Amortization of regulatory deferral debit balance									
Power Smart programs	$ (75 309)	$ (77 059)	$ (75 008)	$ (73 863)	$ (73 203)	$ (72 900)	$ (74 807)	$ (77 517)	$ (80 195)
Change in depreciation method	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)
Deferred ineligible overhead	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)
Loss on disposal of assets	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)
Site restoration costs	(1 724)	(1 514)	(1 334)	(1 046)	(891)	(616)	(433)	(295)	(188)
Regulatory costs	(1 789)	(1 821)	(1 866)	(1 900)	(1 947)	(1 982)	(2 031)	(2 068)	(2 120)
Acquisition costs	(692)	(692)	(678)	(300)	(300)	(199)	(6)	-	-
Affordable Energy Fund	(95)	-	-	-	-	-	-	-	-
Conawapa Generation	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)
DSM deferral	-	-	-	-	-	-	-	-	-
	(119 783)	(121 259)	(119 061)	(117 283)	(116 515)	(115 871)	(117 452)	(120 054)	(122 677)
Closing balance of regulatory deferral debit balance									
Power Smart programs	$ 395 200	$ 397 041	$ 404 833	$ 413 227	$ 423 916	$ 436 640	$ 449 200	$ 460 818	$ 471 556
Change in depreciation method	226 992	209 130	191 269	173 407	155 545	137 684	119 822	101 960	84 098
Deferred ineligible overhead	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128	29 038
Loss on disposal of assets	3 583	3 006	2 429	1 852	1 275	698	121	(456)	(1 032)
Site restoration costs	6 286	4 773	3 439	2 393	1 502	885	452	157	(31)
Regulatory costs	2 760	3 145	2 911	3 313	3 070	3 489	3 235	3 672	3 407
Acquisition costs	2 176	1 484	806	506	206	7	1	1	1
Affordable Energy Fund	11	11	11	11	11	11	11	11	11
Conawapa Generation	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486	165 840
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	1 054 570	**1 014 416**	**979 788**	**947 064**	**916 145**	**888 298**	**859 990**	**831 577**	**801 687**

TABLE 4: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL CREDIT BALANCE

in thousands of dollars

	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of regulatory deferral credit balance											
DSM deferral	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
Additions to regulatory deferral credit balance											
DSM deferral	5 200	-	-	-	-	-	-	-	-	-	-
	5 200	-	-	-	-	-	-	-	-	-	-
Amortization of regulatory deferral credit balance											
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Closing balance of regulatory deferral credit balance											
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	48 800	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**

TABLE 4: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL CREDIT BALANCE

in thousands of dollars

	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of regulatory deferral credit balance									
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
Additions to regulatory deferral credit balance									
DSM deferral	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Amortization of regulatory deferral credit balance									
DSM deferral	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Closing balance of regulatory deferral credit balance									
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	48 800	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**

Figure 2. Net Movement in Regulatory Deferral Accounts (MH16 Update with Interim)

MANITOBA HYDRO (Updated MH16)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS
(000's)

	2016/17 Actual	**2017/18 Forecast**	**2018/19 Forecast**	**2019/20 Forecast**	**2020/21 Forecast**	**2021/22 Forecast**	**2022/23 Forecast**	**2023/24 Forecast**	**2024/25 Forecast**	**2025/26 Forecast**
Additions of regulatory deferral accounts										
Power Smart programs	$ (50 453)	$ (57 184)	$ (99 404)	$ (94 251)	$ (88 857)	$ (86 929)	$ (66 549)	$ (60 271)	$ (62 350)	$ (66 576)
Conawapa Generation	-	-	-	(379 758)	-	-	-	-	-	-
Change in depreciation method	(31 386)	(33 952)	(39 506)	(42 869)	(44 702)	(47 924)	(56 279)	-	-	-
Deferred ineligible overhead	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	-	-	-
Loss on disposal of assets	(1 302)	-	-	-	-	-	-	-	-	-
Site restoration costs	(1 361)	(2 794)	(2 703)	(1 408)	(1 317)	(1 133)	(6)	-	-	-
Regulatory costs	(3 946)	(3 664)	(2 339)	(1 339)	(1 882)	(1 391)	(1 954)	(1 444)	(2 029)	(1 499)
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	(63)	-	-	-	-	-	-	-	-	-
Total additions of regulatory deferral accounts	(108 712)	(117 794)	(164 151)	(539 825)	(156 958)	(157 576)	(144 988)	(61 715)	(64 379)	(68 075)
Amortization of regulatory deferral accounts										
Power Smart programs	34 937	35 742	36 662	43 202	49 473	55 519	61 480	65 459	68 888	71 976
Conawapa Generation	-	-	-	11 592	12 645	12 645	12 645	12 645	12 645	12 645
Affordable Energy Fund	224	449	480	563	545	511	489	454	322	147
Site restoration costs	4 070	4 106	3 990	3 855	3 559	2 990	2 629	2 234	2 170	1 991
Regulatory costs	2 358	2 942	3 665	2 884	2 495	1 883	1 400	1 657	1 684	1 721
Acquisition costs	692	692	692	692	692	692	692	692	692	692
Change in depreciation method	-	-	-	6 437	9 345	11 534	13 850	16 455	17 862	17 862
Loss on disposal of assets	-	288	577	577	577	577	577	577	577	577
Deferred ineligible overhead	-	1 768	4 545	5 555	6 565	7 575	8 585	9 090	9 090	9 090
Total amortization of regulatory deferral accounts	42 281	45 986	50 611	75 357	85 894	93 926	102 347	109 263	113 930	116 700
Total net movement in regulatory deferral balances	$ (66 431)	$ (71 808)	$ (113 540)	$ (464 468)	$ (71 064)	$ (63 651)	$ (42 641)	$ 47 548	$ 49 551	$ 48 625
Year over year $ change		$ (5 377)	$ (41 732)	$ (350 928)	$393 404	$ 7 413	$ 21 010	$ 90 189	$ 2 003	$ (926)
Year over year % change		8%	58%	309%	-85%	-10%	-33%	-212%	4%	-2%

MANITOBA HYDRO (Updated MH16)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS
(000's)

	2026/27 Forecast	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Additions of regulatory deferral accounts										
Power Smart programs	$ (70 722)	$ (74 678)	$ (78 900)	$ (82 801)	$ (82 257)	$ (83 893)	$ (85 623)	$ (87 367)	$ (89 135)	$ (90 933)
Conawapa Generation	-	-	-	-	-	-	-	-	-	-
Change in depreciation method	-	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-	-
Regulatory costs	(2 114)	(1 564)	(2 206)	(1 632)	(2 302)	(1 703)	(2 402)	(1 777)	(2 506)	(1 854)
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-	-
Total additions of regulatory deferral accounts	(72 836)	(76 243)	(81 106)	(84 433)	(84 558)	(85 596)	(88 025)	(89 144)	(91 640)	(92 787)
Amortization of regulatory deferral accounts										
Power Smart programs	73 251	75 309	77 059	75 008	73 863	73 203	72 900	74 807	77 517	80 195
Conawapa Generation	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645
Affordable Energy Fund	97	95	-	-	-	-	-	-	-	-
Site restoration costs	1 826	1 724	1 514	1 334	1 046	891	616	433	295	188
Regulatory costs	1 749	1 789	1 821	1 866	1 900	1 947	1 982	2 031	2 068	2 120
Acquisition costs	692	692	692	678	300	300	199	6	-	-
Change in depreciation method	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862
Loss on disposal of assets	577	577	577	577	577	577	577	577	577	577
Deferred ineligible overhead	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090
Total amortization of regulatory deferral accounts	117 790	119 783	121 259	119 061	117 283	116 515	115 871	117 452	120 054	122 677
Total net movement in regulatory deferral balances	$ 44 955	$ 43 541	$ 40 154	$ 34 627	$ 32 724	$ 30 919	$ 27 846	$ 28 308	$ 28 413	$ 29 890
Year over year $ change	$ (3 670)	$ (1 414)	$ (3 387)	$ (5 526)	$ (1 903)	$ (1 805)	$ (3 073)	$ 462	$ 105	$ 1 477
Year over year % change	-8%	-3%	-8%	-14%	-5%	-6%	-10%	2%	0%	5%

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REFERENCE:

PUB/MH I-22

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please articulate the current future economic benefit to be derived from the Conawapa expenditures to support its carrying value within Manitoba Hydro's balance sheet.

b) Please articulate why the expenditures on Conawapa merit future recognition as a regulatory asset.

c) Please provide a schedule detailing the actual/forecast capital costs incurred on Conawapa Generation and Licencing by year (including a break-down of Other in a similar level of detail to PUB/MH I-17b (2015 & 2016 GRA)).

RATIONALE FOR QUESTION:

RESPONSE:

a) Expenditures related to the Conawapa Generating Station are being maintained in construction work in process through to the end of fiscal 2018/19 pending the direction from the PUB with respect to proposed deferral and subsequent amortization of costs incurred.

b) Regulatory assets represent timing differences between when an expenditure must be recognized for financial reporting purposes and when an expenditure is to be recognized for rate setting purposes, as directed by the entity's regulator. MH16 assumes that, for financial reporting purposes, Manitoba Hydro will be required to write-off 100% of the $380 million deferred Conawapa expenditures to net income in fiscal 2020. Given the material negative impact this write-off would have on the net income, retained earnings and customer rates of Manitoba Hydro, Manitoba Hydro is proposing that the

$380 million be deferred as a regulatory asset and amortized over 30 years so as to minimize the impact on customer rates.

c) Please see the attached schedule detailing the actual capital costs incurred on Conawapa Generation and Licensing by year.

Manitoba Hydro 2016/2017 General Rate Application
PUB/MH-12c Cumulative Detail of the Conawapa Expenditures

CONAWAPA GS								**Fiscal Year**							
In thousands	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Total**
Conawapa - Generation															
Internal MH Staff Costs	$ 49	$ 2 503	$ 4 790	$ 6 762	$ 6 338	$ 5 792	6 292	5 141	5 526	6 880	10 562	3 884	668	576	65 764
External Consultants hired by MH	148	4 096	8 167	12 585	11 748	12 591	6 674	5 238	2 869	4 551	7 176	6 227	1 496	485	84 049
MH Funded Expenses for Costs Incurred by Third Parties	-	26	415	3 107	1 540	670	1 313	628	59	352	2 263	3 260	93	1	13 726
Materials & Other	-	1 563	13 992	5 239	4 707	2 294	2 305	4 116	3 299	309	302	276	98	62	38 561
Joint Generation Development Agreements, Process and Study Costs	-	291	734	1 510	3 958	3 961	3 699	2 414	2 431	3 146	3 477	3 903	1 790	1 642	32 956
Mitigation	-	-	-	-	-	-	4 800	-	-	-	-	-	-	-	4 800
Capitalized Interest	-	(1)	-	3 434	5 740	8 120	10 087	12 187	14 019	15 496	16 716	18 921	19 633	15 027	139 379
	197	8 478	28 098	32 636	34 030	33 429	35 169	29 724	28 203	30 733	40 496	36 471	23 778	17 793	$ 379 235

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REFERENCE:

Tab 3, Page 19
Tab 6, Page 42

PREAMBLE TO IR (IF ANY):

QUESTION:

Tab 3 indicates that the Conawapa costs will be recognized in deferral accounts and amortized commencing April 1, 2019 and total $380 M. Have the Conawapa costs to be amortized changed since the last GRA and, if yes, why?

RATIONALE FOR QUESTION:

To clarify the basis for the Conawapa costs.

RESPONSE:

Since the last GRA, project costs related to Conawapa have decreased by $17 million to $380 million to reflect lower costs associated with environmental studies/field work and agreements costs related to Aboriginal Traditional Knowledge (ATK) studies.

In addition, interest was discontinued upon completion of all wind-down activities, effective December 31, 2016, in accordance with International Accounting Standards (IAS) 23 - Borrowing Costs, which states that *"An entity shall suspend capitalization of borrowing costs during extended periods in which it suspends active development of a qualifying asset."*

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REFERENCE:

Tab 3, pg. 18

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the accounting issues paper related to the treatment of Conawapa under IAS 36 Impairment including the rationale surrounding the following assumptions:

a) Future economic benefits to support the carrying amount of the $380 million CWIP balance until April 1, 2019 (anticipated write-off date);
b) Eligibility of the recovery of the balance through the regulatory deferral account and the rationale for the 30-year write-off period

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) and b):

An issues paper relating to the accounting treatment of Conawapa under the IAS 36 Impairment standard was not prepared as it was Manitoba Hydro's intent, should a decision be made to ultimately suspend Conawapa to seek PUB endorsement of the inclusion of costs incurred with respect to the Conawapa Generating Station project into Manitoba Hydro's regulatory deferral balances with subsequent amortization. As such, Manitoba Hydro assumed there would be no impairment of the Construction Work In Progress balance.

It was decided to maintain the costs in Construction Work In Progress while the federal government was determining its strategy for federal carbon reduction initiatives. Overall, the assumption was that there was enough uncertainty with respect to the timing of such initiatives to warrant deferring the Conawapa project costs in Construction Work In Progress through to the end of fiscal 2018/19. MH16 assumes

Conawapa costs are recognized as a regulatory deferral account, with amortization commencing effective April 1, 2019.

The 30 year amortization period was assumed in order to minimize the potential further impact on rates.

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REFERENCE:

Appendix 3.6

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the 20 year financial forecast schedules for MH16 (Updated) that separately tracks Conawapa cost treatment in the projected operating statement, balance sheet and cash flow statement.

RATIONALE FOR QUESTION:

RESPONSE:

Please see the MH16 Update with Interim financial statements below with the cost treatment of Conawapa separately tracked.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim Reflecting Conawapa Cost Treatment
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Gross Finance Expense	*623*	*587*	*677*	*744*	*817*	*882*	*1 115*	*1 140*	*1 123*	*1 092*	*1 056*
Conawapa Generation	*(15)*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	176
Gross Other Expenses	*60*	*116*	*109*	*102*	*94*	*92*	*71*	*64*	*67*	*71*	*76*
Conawapa Generation	*-*	*-*	*-*	*380*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Gross Net Movement in Regulatory Deferral	*66*	*72*	*114*	*96*	*84*	*76*	*55*	*(35)*	*(37)*	*(36)*	*(32)*
Conawapa Generation	*-*	*-*	*-*	*368*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Gross Net Income	*26*	*85*	*209*	*219*	*366*	*539*	*456*	*436*	*545*	*504*	*593*
Conawapa Generation	*15*	*-*	*-*	*(12)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Gross Manitoba Hydro	*38*	*93*	*211*	*217*	*361*	*530*	*446*	*424*	*542*	*501*	*589*
Conawapa Generation	*15*	*0*	*0*	*(12)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	208	354	526	443	423	533	491	580
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim Reflecting Conawapa Cost Treatment
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Gross Finance Expense	*1 037*	*1 020*	*994*	*909*	*850*	*800*	*742*	*675*	*618*
Conawapa Generation	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Finance Expense	1 037	1 020	994	909	850	800	742	675	618
Finance Income	(29)	(46)	(57)	(18)	(19)	(19)	(26)	(32)	(50)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	183	184	190
Gross Other Expenses	*79*	*84*	*87*	*87*	*89*	*91*	*92*	*95*	*96*
Conawapa Generation	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 894	2 892	2 888	2 878	2 833	2 818	2 792	2 762	2 714
Net Income before Net Movement in Reg. Deferral	698	801	915	1 032	1 189	1 320	1 465	1 623	1 714
Gross Net Movement in Regulatory Deferral	*(31)*	*(28)*	*(22)*	*(20)*	*(18)*	*(15)*	*(16)*	*(16)*	*(17)*
Conawapa Generation	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Gross Net Income	*667*	*773*	*893*	*1 012*	*1 170*	*1 305*	*1 449*	*1 607*	*1 697*
Conawapa Generation	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*
Net Income	654	761	880	999	1 158	1 292	1 437	1 595	1 684
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	650	755	873	989	1 147	1 280	1 423	1 579	1 668
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Gross Manitoba Hydro	*663*	*768*	*885*	*1 002*	*1 159*	*1 292*	*1 435*	*1 592*	*1 681*
Conawapa Generation	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*	*(13)*
Manitoba Hydro	**650**	**755**	**873**	**989**	**1 147**	**1 280**	**1 423**	**1 579**	**1 668**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	654	761	880	999	1 158	1 292	1 437	1 595	1 684
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	27%	30%	33%	37%	41%	46%	52%	57%	64%
EBITDA Interest Coverage	2.48	2.65	2.85	3.09	3.45	3.79	4.25	4.86	5.52
Capital Coverage	2.39	2.47	2.68	2.71	2.93	3.08	3.25	3.16	3.23

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim Reflecting Conawapa Cost Treatment
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2016	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS												
Plant in Service		13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation		(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service		12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Gross Construction in Progress		*6 699*	*9 091*	*6 365*	*7 522*	*8 012*	*3 836*	*367*	*454*	*418*	*414*	*411*
Conawapa Generation	*361*	*380*	*380*	*380*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Construction in Progress		7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Gross Current and Other Assets		*1 776*	*1 918*	*2 272*	*2 500*	*2 572*	*1 946*	*1 775*	*1 992*	*2 233*	*2 088*	*2 202*
Conawapa Generation		*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*
Current and Other Assets		1 773	1 915	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
Goodwill and Intangible Assets		327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral		21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
Gross Regulatory Deferral Balance		*462*	*533*	*647*	*743*	*827*	*903*	*959*	*924*	*887*	*851*	*818*
Conawapa Generation		*-*	*-*	*-*	*368*	*356*	*343*	*330*	*318*	*305*	*292*	*280*
Regulatory Deferral Balance		462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
		21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY												
Long-Term Debt		15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities		3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions		70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue		450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account		196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Gross Retained Earnings		*2 734*	*2 827*	*3 037*	*3 254*	*3 615*	*4 146*	*4 592*	*5 016*	*5 558*	*6 060*	*6 649*
Conawapa Generation		*15*	*15*	*15*	*3*	*(9)*	*(22)*	*(35)*	*(47)*	*(60)*	*(72)*	*(85)*
Retained Earnings		2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income		(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral		21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance		49	49	49	49	49	49	49	49	49	49	49
		21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt		15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity		2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio		16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim Reflecting Conawapa Cost Treatment
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Gross Construction in Progress	*493*	*454*	*490*	*400*	*374*	*366*	*406*	*461*	*257*
Conawapa Generation	-	-	-	-	-	-	-	-	-
Construction in Progress	493	454	490	400	374	366	406	461	257
Gross Current and Other Assets	*2 827*	*3 633*	*2 362*	*2 044*	*2 281*	*2 628*	*3 632*	*4 071*	*5 512*
Conawapa Generation	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*
Current and Other Assets	2 824	3 630	2 359	2 041	2 278	2 625	3 629	4 069	5 509
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	31 004	31 781	30 458	30 114	30 315	30 623	31 584	32 041	33 501
Gross Regulatory Deferral Balance	*788*	*760*	*738*	*718*	*700*	*684*	*669*	*653*	*636*
Conawapa Generation	*267*	*254*	*242*	*229*	*216*	*204*	*191*	*178*	*166*
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 751	14 977	14 280	13 859	13 743
Current and Other Liabilities	2 920	5 271	7 325	5 089	5 140	3 906	4 103	3 363	3 230
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Gross Retained Earnings	*7 311*	*8 080*	*8 965*	*9 967*	*11 126*	*12 418*	*13 853*	*15 445*	*17 126*
Conawapa Generation	*(98)*	*(110)*	*(123)*	*(136)*	*(148)*	*(161)*	*(174)*	*(186)*	*(199)*
Retained Earnings	7 214	7 969	8 842	9 831	10 977	12 257	13 680	15 259	16 927
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	32 010	32 747	31 389	31 012	31 183	31 463	32 395	32 824	34 254
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
Net Debt	20 197	19 357	18 386	17 327	16 094	14 725	13 200	11 587	9 877
Total Equity	7 564	8 325	9 206	10 203	11 357	12 645	14 077	15 665	17 343
Equity Ratio	27%	30%	33%	37%	41%	46%	52%	57%	64%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim Reflecting Conawapa Cost Treatment
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Gross Interest Paid	*(568)*	*(531)*	*(635)*	*(700)*	*(762)*	*(834)*	*(1 063)*	*(1 112)*	*(1 101)*	*(1 072)*	*(1 037)*
Conawapa Generation	*15*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Gross PP&E	*(2 907)*	*(3 660)*	*(3 002)*	*(2 391)*	*(1 760)*	*(1 368)*	*(898)*	*(700)*	*(704)*	*(732)*	*(756)*
Conawapa Generation	*(18)*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Gross Net Increase (Decrease in Cash)	*(306)*	*(145)*	*74*	*(18)*	*19*	*(236)*	*146*	*(16)*	*295*	*(283)*	*71*
Conawapa Generation	*(3)*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Gross Cash at End of Year	*637*	*491*	*565*	*547*	*566*	*331*	*477*	*461*	*757*	*473*	*544*
Conawapa Generation	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim Reflecting Conawapa Cost Treatment
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 087)	(1 097)
Gross Interest Paid	*(1 019)*	*(1 014)*	*(997)*	*(908)*	*(837)*	*(795)*	*(742)*	*(696)*	*(632)*
Conawapa Generation	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Interest Paid	(1 019)	(1 014)	(997)	(908)	(837)	(795)	(742)	(696)	(632)
Interest Received	26	51	63	20	15	22	36	49	67
	1 604	1 720	1 843	1 972	2 155	2 307	2 473	2 637	2 752
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 150	1 140	360	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(195)	(193)	(188)	(189)	(184)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 223)	(1 219)	(704)	(1 383)	(209)
INVESTING ACTIVITIES									
Gross PP&E	*(767)*	*(798)*	*(793)*	*(832)*	*(840)*	*(857)*	*(870)*	*(948)*	*(966)*
Conawapa Generation	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Gross Net Increase (Decrease in Cash)	*505*	*594*	*(1 229)*	*(41)*	*19*	*160*	*829*	*238*	*1 510*
Conawapa Generation	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*	*-*
Net Increase (Decrease) in Cash	505	594	(1 229)	(41)	19	160	829	238	1 510
Cash at Beginning of Year	541	1 047	1 640	411	370	389	549	1 378	1 616
Gross Cash at End of Year	*1 049*	*1 643*	*414*	*373*	*392*	*552*	*1 381*	*1 619*	*3 128*
Conawapa Generation	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*	*(3)*
Cash at End of Year	1 047	1 640	411	370	389	549	1 378	1 616	3 126

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REFERENCE:

PUB/MH I-22

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please refile IFF16 Update with Interim assuming the costs related to Conawapa are written off and are not recovered through a regulatory deferral asset, indicated rate increases are to remain the same.

RATIONALE FOR QUESTION:

RESPONSE:

The following projected financial statements provide a scenario based on MH16 Update with Interim where the costs related to Conawapa are written off to Other Expenses in 2020 and not recovered through a regulatory deferral asset. The write-off results in a $161 million loss in 2020 and a 1-year delay in restoring Manitoba Hydro's capital structure to 25% equity to 2028 absent any compensating adjustment to the indicative profile of rate increases in the 2024/25 to 2026/27 time frame.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	881	1 114	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(28)	(22)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	152	159	164	173	173	174	174	174
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 653	2 390	2 505	2 820	2 891	2 902	2 885	2 887
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(255)	285	465	403	472	584	541	627
Net Movement in Regulatory Deferral	66	72	114	96	84	76	55	(35)	(37)	(36)	(32)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	(159)	368	541	458	437	547	505	594
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	(161)	363	532	448	426	544	503	591
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**(161)**	**363**	**532**	**448**	**426**	**544**	**503**	**591**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	(159)	368	541	458	437	547	505	594
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	13%	14%	15%	16%	18%	20%	22%	24%
EBITDA Interest Coverage	1.51	1.54	1.71	1.36	1.85	2.02	2.03	2.08	2.22	2.24	2.37
Capital Coverage	1.53	1.40	1.48	1.48	1.88	2.35	2.25	2.37	2.34	2.20	2.30

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	907	850	799	739	665	607
Finance Income	(29)	(47)	(57)	(17)	(20)	(19)	(24)	(27)	(46)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	176	177	178	179	180	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 892	2 890	2 886	2 876	2 831	2 815	2 789	2 755	2 707
Net Income before Net Movement in Reg. Deferral	699	803	917	1 034	1 191	1 322	1 468	1 630	1 721
Net Movement in Regulatory Deferral	(31)	(28)	(22)	(20)	(18)	(15)	(16)	(16)	(17)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	668	775	895	1 014	1 172	1 307	1 453	1 614	1 703
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	664	770	887	1 004	1 161	1 295	1 438	1 599	1 687
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**664**	**770**	**887**	**1 004**	**1 161**	**1 295**	**1 438**	**1 599**	**1 687**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	668	775	895	1 014	1 172	1 307	1 453	1 614	1 703
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	27%	29%	33%	37%	41%	46%	51%	57%	64%
EBITDA Interest Coverage	2.49	2.65	2.85	3.09	3.46	3.80	4.27	4.90	5.58
Capital Coverage	2.39	2.47	2.68	2.71	2.94	3.08	3.25	3.17	3.24

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	ACTUAL										
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 499	2 572	1 952	1 784	2 002	2 245	2 102	2 217
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 454	30 064	30 132	30 205	30 373	30 557	30 367	30 442
Regulatory Deferral Balance	462	533	647	743	827	903	959	924	887	851	818
	21 733	24 839	27 774	29 197	30 891	31 036	31 163	31 296	31 444	31 217	31 260
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 145	3 024	3 178	3 459	3 980	2 979
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	2 891	3 254	3 787	4 235	4 661	5 205	5 708	6 299
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 148	30 842	30 987	31 115	31 247	31 395	31 168	31 211
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 197	30 891	31 036	31 163	31 296	31 444	31 217	31 260
Net Debt	15 427	18 473	20 743	22 405	23 292	23 600	23 377	22 819	22 186	21 597	20 928
Total Equity	2 856	3 163	3 511	3 403	3 792	4 329	4 461	4 954	5 513	6 030	6 635
Equity Ratio	16%	15%	14%	13%	14%	15%	16%	18%	20%	22%	24%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 844	3 652	2 383	2 065	2 309	2 653	3 457	3 903	5 350
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	31 024	31 803	30 482	30 138	30 346	30 651	31 412	31 875	33 342
Regulatory Deferral Balance	788	760	738	718	700	684	669	653	636
	31 812	32 563	31 220	30 856	31 045	31 335	32 081	32 528	33 978
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 751	14 977	14 080	13 659	13 543
Current and Other Liabilities	2 924	5 274	7 328	5 091	5 146	3 907	4 100	3 360	3 228
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	6 964	7 733	8 620	9 625	10 786	12 080	13 519	15 117	16 805
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	31 763	32 514	31 171	30 807	30 997	31 287	32 032	32 480	33 929
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 812	32 563	31 220	30 856	31 045	31 335	32 081	32 528	33 978
Net Debt	20 177	19 335	18 362	17 302	16 063	14 697	13 172	11 552	9 836
Total Equity	7 314	8 090	8 984	9 996	11 166	12 469	13 916	15 524	17 221
Equity Ratio	27%	29%	33%	37%	41%	46%	51%	57%	64%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	ACTUAL										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(868)	(883)	(892)	(902)	(934)	(951)	(951)	(965)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(830)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	15
	810	734	767	761	963	1 174	1 173	1 289	1 439	1 410	1 514
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(16)	21	(230)	148	(14)	297	(281)	73
Cash at Beginning of Year	943	634	488	562	546	567	337	485	471	769	487
Cash at End of Year	634	488	562	546	567	337	485	471	769	487	560

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(979)	(995)	(1 011)	(1 034)	(1 029)	(1 042)	(1 062)	(1 086)	(1 096)
Interest Paid	(1 019)	(1 014)	(997)	(909)	(833)	(799)	(742)	(685)	(622)
Interest Received	26	51	64	19	16	22	34	44	63
	1 606	1 722	1 845	1 973	2 161	2 304	2 473	2 644	2 758
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 150	1 140	160	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(194)	(192)	(188)	(187)	(182)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 222)	(1 219)	(904)	(1 381)	(207)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	507	595	(1 227)	(41)	26	158	629	247	1 519
Cash at Beginning of Year	560	1 067	1 662	435	394	420	577	1 206	1 453
Cash at End of Year	1 067	1 662	435	394	420	577	1 206	1 453	2 971

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Note 20 Regulatory deferral balances

	March 31, 2016	Balances arising in the year	Recovery / reversal	**March 31, 2017**	Remaining recovery / reversal period
					(years)
Regulatory deferral debit balances					
Electric					
DSM programs[1]	232	56	(35)	**253**	1 - 10
Site restoration	31	1	(4)	**28**	1 - 15
Change in depreciation method	60	31	-	**91**	*
Deferred ineligible overhead	40	21	-	**61**	*
Acquisition costs	10	-	(1)	**9**	15 - 18
Affordable Energy Fund	4	-	-	**4**	**
Loss on disposal of assets	9	1	-	**10**	*
Regulatory costs	4	4	(2)	**6**	1 - 5
Gas					
DSM programs[1]	57	13	(9)	**61**	1 - 10
Deferred taxes	23	2	(4)	**21**	1 - 30
Site restoration	3	-	-	**3**	1 - 15
Loss on disposal of assets	6	3	-	**9**	*
Change in depreciation method	4	2	-	**6**	*
Regulatory costs	1	1	(1)	**1**	1 - 5
Deferred ineligible overhead	2	-	-	**2**	*
Change in depreciation rate - meters	-	1	-	**1**	*
	486	136	(56)	**566**	
Regulatory deferral credit balances					
Electric					
DSM deferral	43	6	-	**49**	*
Gas					
DSM deferral	6	2	-	**8**	*
PGVA	1	(182)	198	**17**	***
Impact of 2014 depreciation study	2	1	-	**3**	*
	52	(173)	198	**77**	
Net movement in regulatory balances		309	(254)	**55**	

[1] Included in DSM programs is the difference between actual and planned expenditures for electric and gas DSM programs.

* The amortization periods for these accounts will be determined by the PUB as part of a future regulatory proceeding.

** The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the provision (Note 27) is drawn down.

*** The PGVA is recovered or refunded in future rates.

	March 31, 2015	Balances arising in the year	Recovery / reversal	March 31, 2016	Remaining recovery / reversal period
					(years)
Regulatory deferral debit balances					
Electric					
DSM programs[1]	184	81	(33)	232	1 - 10
Site restoration	31	3	(3)	31	1 - 15
Change in depreciation method	29	31	-	60	*
Deferred ineligible overhead	20	20	-	40	*
Acquisition costs	11	-	(1)	10	15 - 18
Affordable Energy Fund	6	-	(2)	4	**
Loss on disposal of assets	6	3	-	9	*
Regulatory costs	1	4	(1)	4	1 - 5
Gas					
DSM programs[1]	55	10	(8)	57	1 - 10
PGVA	32	181	(213)	-	***
Deferred taxes	25	2	(4)	23	1 - 30
Site restoration	3	-	-	3	1 - 15
Loss on disposal of assets	3	3	-	6	*
Change in depreciation method	2	2	-	4	*
Regulatory costs	1	1	(1)	1	1 - 5
Deferred ineligible overhead	1	1	-	2	*
	410	342	(266)	486	
Regulatory deferral credit balances					
Electric					
DSM deferral	16	27	-	43	*
Gas					
DSM deferral	6	-	-	6	*
PGVA	-	-	1	1	***
Impact of 2014 depreciation study	1	1	-	2	*
	23	28	1	52	
Net movement in regulatory balances		314	(267)	47	

[1] Included in DSM programs is the difference between actual and planned expenditures for electric and gas DSM programs.

* The amortization periods for these accounts will be determined by the PUB as part of a future regulatory proceeding.

** The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the provision (Note 27) is drawn down.

*** The PGVA is recovered or refunded in future rates.

The balances arising in the year consist of additions to regulatory deferral balances. The recovery/reversal consists of amounts recovered from customers through the amortization of existing regulatory balances or rate riders. The net impact of these transactions results in the net movement in regulatory deferral balances on the consolidated statement of income.

Balances arising in the year include $2 million (2016 - $2 million) for carrying costs on deferred taxes, the Affordable Energy Fund and the PGVA.

The regulatory deferral debit balances of the corporation consist of the following:

DSM program expenditures are incurred for energy conservation programs to encourage residential, commercial and industrial customers to use energy more efficiently.

Site restoration expenditures are incurred for the remediation of contaminated corporate facilities and diesel generating sites.

Change in depreciation method represents the cumulative annual difference in depreciation expense between the ASL method of depreciation as applied by Manitoba Hydro prior to its transition to IFRS and the ELG method as applied by Manitoba Hydro under IFRS.

Deferred ineligible overhead is the cumulative annual difference in overhead capitalized for financial reporting purposes under IFRS and overhead capitalized for rate setting purposes.

Acquisition costs relate to costs associated with the acquisition of Centra and Minell (July 1999) and Winnipeg Hydro (September 2002).

The Affordable Energy Fund relates to future DSM expenditures in connection with *The Winter Heating Cost Control Act*. The intent of the Affordable Energy Fund is to provide funding for projects that would not otherwise be funded by DSM programs.

Loss on disposal of assets is the net asset retirement losses for those assets retired prior to or subsequent to reaching their expected service life as determined under the ELG method of depreciation.

Regulatory costs are those incurred as a result of electric and gas regulatory hearings.

Deferred taxes are the taxes paid by Centra (July 1999) as a result of its change to non-taxable status upon acquisition by Manitoba Hydro.

REFERENCE:

Tab 6, Page 42, Fig. 6.30
Appendix 3.1, Pages 57-58
Appendix 3.6, Pages 1-2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a revised version of Figure 6.30 that includes the years up to 2033/34.

b) For each of the line items under "Additions to Regulatory Deferral Accounts", please indicate under which Revenue/Expense item in the Income Statement the revenue/cost was initially recorded.

c) Please provide an updated response to part (a) based on the IFF16-Update.

RATIONALE FOR QUESTION:

To understand the basis for the values provide in the IFFs regarding Net Movement in Regulatory Deferral Balances, particularly the year over year changes.

RESPONSE:

a) Please see Manitoba Hydro's response to MIPUG/MH I-6b (Figure 1) for a revised version of Figure 6.30 based on MH16.

b) The table below outlines which Revenue/Expense item in the Income Statement the additions to regulatory deferral accounts were initially recorded.

Regulatory Deferral Account	Initial Revenue/Expense Item from Income Statement
Power Smart programs	Other Expenses
Change in depreciation method	Depreciation and Amortization
Deferred ineligible overhead	Operating and Administrative
Loss on disposal of assets	Depreciation and Amortization
Site restoration costs	Other Expenses
Regulatory costs	Other Expenses
Acquisition costs	Other Expenses
Affordable Energy Fund	Finance Expense
Conawapa Generation	Other Expenses

c) Please see Manitoba Hydro's response to MIPUG/MH I-6b (Figure 2) for a revised version of Figure 6.30 based on the MH16 Update with Interim.

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REFERENCE:

Tab 6, Page 37
Appendix 3.1, Page 57
Tab 3, Page 8
2016/17 Supplemental Filing, Attachment 1, Page 41

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a version of MH15 (similar in detail to that in Attachment 1 referenced above) consistent with the values used in Figure 3.4.

c) Please identify any discrepancies in the MH15 values reported in Figure 3.4 and the response to part (b) with values reported in the MH15 forecast provided in the 2016/17 Supplemental Filing (Attachment 1) and reconcile the differences.

d) Are the MH15 and MH16 values used for Figure 3.4 determined on a comparable basis or are there differences due to difference in accounting treatment or the line item under which certain costs are reported. If there are differences, please indicate what they are.

e) With respect to MH16, please provide a schedule that identifies those costs that are reported as Other Expenses for the years 2016/17 through 2033/34 but are subsequently treated as additions to regulatory deferral accounts.

f) With the adjustments identified in part (e), is Other Expense as reported in MH16 is comparable to that reported in MH14. If not, what other adjustments are required?

RATIONALE FOR QUESTION:

To understand the differences between the various forecasts of Other Expense.

RESPONSE:

b) The following MH15 projected financial statement was restated to be consistent with the presentation in MH16 and used to support Figure 3.4.

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610	1 626	1 641
additional*	61	125	191	258	335	411	493	580	672	769	872
BPIII Reserve Account	(67)	(69)	(21)	87	87	87	-	-	-	-	-
Extraprovincial	406	449	474	548	825	966	979	983	986	884	903
Other	28	28	29	30	31	32	32	32	33	34	35
	1 985	2 086	2 225	2 465	2 844	3 066	3 087	3 191	3 301	3 313	3 450
EXPENSES											
Operating and Administrative	552	557	571	585	601	607	619	631	644	657	669
Finance Expense	601	598	747	863	1 110	1 209	1 195	1 197	1 196	1 180	1 175
Finance Income	(13)	(19)	(31)	(39)	(31)	(21)	(15)	(15)	(19)	(13)	(18)
Depreciation and Amortization	383	398	472	521	617	663	677	691	707	723	739
Water Rentals and Assessments	116	113	113	115	124	127	132	132	132	132	133
Fuel and Power Purchased	151	182	180	174	206	228	227	230	242	231	241
Capital and Other Taxes	122	136	145	146	149	157	157	163	165	166	167
Other Expenses	66	104	98	95	95	100	77	69	74	81	84
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 986	2 078	2 302	2 468	2 879	3 078	3 077	3 107	3 148	3 164	3 199
Net Income before Net Movement in Reg. Deferral	(1)	8	(77)	(3)	(35)	(12)	10	84	153	149	251
Net Movement in Regulatory Deferral	21	50	33	25	20	19	(11)	(22)	(21)	(19)	(17)
Net Income	20	59	(44)	21	(15)	7	(1)	62	131	130	234
Net Income Attributable to:											
Manitoba Hydro	**29**	**63**	**(41)**	**21**	**(13)**	**6**	**(4)**	**56**	**129**	**129**	**232**
Non-controlling Interest	(9)	(4)	(3)	(0)	(2)	1	3	5	3	1	2
* Additional Domestic Revenue											
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%
Financial Ratios											
Equity	14%	14%	13%	13%	13%	12%	12%	12%	13%	13%	14%
EBITDA Interest Coverage	1.52	1.52	1.46	1.54	1.57	1.62	1.63	1.70	1.78	1.81	1.92
Capital Coverage	0.98	1.21	1.05	1.06	1.13	1.32	1.49	1.59	1.60	1.61	1.78

c) The following schedule highlights the MH15 line items that were restated for the purposes of making direct comparisons in MH16 in Figure 3.4 in comparison with MH15 filed in the 2016/17 Supplemental Filing (Attachment 1).

	MH15 2017/18 & 2018/19 GRA Figure 3.4		MH15 2016/17 Supplemental Filing Attachment 1		Difference	
	2017-2019	2017-2027	2017-2019	2017-2027	2017-2019	2017-2027
REVENUES						
Domestic Revenue						
at approved rates	4 661	17 394	4 661	17 394	-	-
additional*	378	4 767	378	4 767	-	-
BPIII Reserve Account	(157)	103	(157)	(157)	-	260
Extraprovincial	1 329	8 402	1 329	8 402	-	-
Other	86	344	86	605	-	(260)
	6 296	31 011	6 296	31 011	-	-
EXPENSES						
Operating and Administrative	1 680	6 693	1 680	6 693	-	-
Finance Expense	1 946	11 070	1 883	10 837	63	233
Finance Income	(63)	(233)	-	-	(63)	(233)
Depreciation and Amortization	1 253	6 590	1 253	6 590	-	-
Water Rentals and Assessments	341	1 369	341	1 369	-	-
Fuel and Power Purchased	513	2 292	513	2 292	-	-
Capital and Other Taxes	402	1 671	402	1 671	-	-
Other Expenses	268	942	268	942	-	-
Corporate Allocation	25	90	25	90	-	-
	6 366	30 486	6 366	30 486	-	-
Net Income before Net Movement in Reg. Deferral	(70)	525	(70)	525	-	-
Net Movement in Regulatory Deferral	105	79	105	79	-	-
Net Income	35	604	35	604	-	-
Net Income Attributable to:						
Manitoba Hydro	**51**	**607**	**51**	**607**	**-**	**-**
Non-controlling Interest	(16)	(2)	(16)	(2)	-	-

d) The restatements of MH15 line items for comparison purposes in Figure 3.4 relate to:

- Reclassification of amortization of the Bipole III Deferral Account from Other Revenue to the BPIII Reserve; and,
- The presentation of Finance Income separately from Finance Expense in in accordance with IFRS.

e) The following schedule provides a breakdown of costs reported as Other Expenses in MH16 and the costs that are subsequently treated as additions to regulatory deferral accounts.

	MH16 OTHER EXPENSES *in millions of dollars*																	
	2017 ACTUAL	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Other Expense Components:																		
Power Smart expenses	50.1	55.7	99.4	94.3	88.9	86.9	66.5	60.3	62.3	66.6	70.7	74.7	78.9	82.8	82.3	83.9	85.6	87.4
Site restoration	1.4	2.8	2.7	1.4	1.3	1.1	0.0	-	-	-	-	-	-	-	-	-	-	-
Regulatory costs	4.4	3.7	2.3	1.3	1.9	1.4	2.0	1.4	2.0	1.5	2.1	1.6	2.2	1.6	2.3	1.7	2.4	1.8
Conawapa Generation	-	-	-	379.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cost of services provided to external entities	0.3	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9
Consulting engagement	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate restructuring costs	-	50.4	2.2	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MH16 Other Expenses	**60.5**	**114.9**	**109.0**	**481.3**	**94.5**	**91.9**	**71.0**	**64.3**	**67.0**	**70.7**	**75.5**	**79.0**	**83.9**	**87.3**	**87.4**	**88.5**	**91.0**	**92.2**
Transfers to Net Movement:																		
Power Smart expenses	(50.1)	(55.7)	(99.4)	(94.3)	(88.9)	(86.9)	(66.5)	(60.3)	(62.3)	(66.6)	(70.7)	(74.7)	(78.9)	(82.8)	(82.3)	(83.9)	(85.6)	(87.4)
Site restoration	(1.4)	(2.8)	(2.7)	(1.4)	(1.3)	(1.1)	(0.0)	-	-	-	-	-	-	-	-	-	-	-
Regulatory costs	(4.4)	(3.7)	(2.3)	(1.3)	(1.9)	(1.4)	(2.0)	(1.4)	(2.0)	(1.5)	(2.1)	(1.6)	(2.2)	(1.6)	(2.3)	(1.7)	(2.4)	(1.8)
Conawapa Generation	-	-	-	(379.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(56.0)	**(62.1)**	**(104.4)**	**(476.8)**	**(92.1)**	**(89.5)**	**(68.5)**	**(61.7)**	**(64.4)**	**(68.1)**	**(72.8)**	**(76.2)**	**(81.1)**	**(84.4)**	**(84.6)**	**(85.6)**	**(88.0)**	**(89.1)**
MH16 Other Expenses Restated	**4.5**	**52.7**	**4.5**	**4.6**	**2.4**	**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**

f) After removing the one-time consulting engagement costs and the corporate restructuring costs, the costs are comparable to MH14. Please see the schedule below.

MH16 OTHER EXPENSES
in millions of dollars

	2017 ACTUAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cost of services provided to external entities	0.3	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9
Consulting engagement	4.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate restructuring costs	-	50.4	2.2	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Miscellaneous	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
MH16 Other Expenses Restated From (e)	**4.5**	**52.7**	**4.5**	**4.6**	**2.4**	**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**
Adjustments:																		
Consulting engagement	(4.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate restructuring costs	-	(50.4)	(2.2)	(2.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	(4.1)	**(50.4)**	**(2.2)**	**(2.2)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
MH16 Other Expenses Adjusted	**0.4**	**2.3**	**2.3**	**2.4**	**2.4**	**2.5**	**2.5**	**2.6**	**2.6**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.9**	**2.9**	**3.0**	**3.0**

MH14 OTHER EXPENSES
in millions of dollars

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Cost of services provided to external entities	2.4	2.5	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.7	2.7
MH14 Other Expenses	**2.4**	**2.5**	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**	**2.8**	**2.8**	**2.3**	**2.4**	**2.4**	**2.5**	**2.5**	**2.5**	**2.6**	**2.7**	**2.7**

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Figure 1. Net Movement in Regulatory Deferral Accounts (MH16)

MANITOBA HYDRO (MH16)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS
(000's)

	2016/17 Outlook	**2017/18 Forecast**	**2018/19 Forecast**	**2019/20 Forecast**	**2020/21 Forecast**	**2021/22 Forecast**	**2022/23 Forecast**	**2023/24 Forecast**	**2024/25 Forecast**	**2025/26 Forecast**
Additions of regulatory deferral accounts										
Power Smart programs	$ (50 143)	$ (55 678)	$ (99 404)	$ (94 251)	$ (88 857)	$ (86 929)	$ (66 549)	$ (60 271)	$ (62 350)	$ (66 576)
Conawapa Generation	-	-	-	(379 758)	-	-	-	-	-	-
Change in depreciation method	(32 562)	(33 952)	(39 506)	(42 869)	(44 702)	(47 924)	(56 279)	-	-	-
Deferred ineligible overhead	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	-	-	-
Loss on disposal of assets	(3 200)	-	-	-	-	-	-	-	-	-
Site restoration costs	(1 424)	(2 794)	(2 703)	(1 408)	(1 317)	(1 133)	(6)	-	-	-
Regulatory costs	(4 389)	(3 664)	(2 339)	(1 339)	(1 882)	(1 391)	(1 954)	(1 444)	(2 029)	(1 499)
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-	-
Total additions of regulatory deferral accounts	(111 918)	(116 288)	(164 151)	(539 825)	(156 958)	(157 576)	(144 988)	(61 715)	(64 379)	(68 075)
Amortization of regulatory deferral accounts										
Power Smart programs	34 937	35 742	36 512	43 052	49 322	55 368	61 329	65 308	68 737	71 825
Conawapa Generation	-	-	-	11 592	12 645	12 645	12 645	12 645	12 645	12 645
Affordable Energy Fund	705	449	480	563	545	511	489	454	322	147
Site restoration costs	4 106	4 106	3 990	3 855	3 559	2 990	2 629	2 234	2 170	1 991
Regulatory costs	2 723	2 942	3 666	2 884	2 495	1 883	1 400	1 657	1 684	1 721
Acquisition costs	692	692	692	692	692	692	692	692	692	692
Change in depreciation method	-	2 724	7 285	9 345	11 534	13 850	16 455	17 862	17 862	17 862
Loss on disposal of assets	-	288	577	577	577	577	577	577	577	577
Deferred ineligible overhead	-	1 768	4 545	5 555	6 565	7 575	8 585	9 090	9 090	9 090
Total amortization of regulatory deferral accounts	43 163	48 711	57 746	78 114	87 933	96 091	104 801	110 520	113 780	116 550
Total net movement in regulatory deferral balances	$ (68 755)	$ (67 577)	$ (106 405)	$ (461 711)	$ (69 025)	$ (61 486)	$ (40 186)	$ 48 804	$ 49 401	$ 48 474
Year over year $ change		$ 1 178	$ (38 828)	$ (355 306)	$392 685	$ 7 540	$ 21 299	$ 88 991	$ 596	$ (926)
Year over year % change		-2%	57%	334%	-85%	-11%	-35%	-221%	1%	-2%

MANITOBA HYDRO (MH16)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS
(000's)

	2026/27 Forecast	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Additions of regulatory deferral accounts										
Power Smart programs	$ (70 722)	$ (74 678)	$ (78 900)	$ (82 801)	$ (82 257)	$ (83 893)	$ (85 623)	$ (87 367)	$ (89 135)	$ (90 933)
Conawapa Generation	-	-	-	-	-	-	-	-	-	-
Change in depreciation method	-	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-	-
Regulatory costs	(2 114)	(1 564)	(2 206)	(1 632)	(2 302)	(1 703)	(2 402)	(1 777)	(2 506)	(1 854)
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-	-
Total additions of regulatory deferral accounts	(72 836)	(76 243)	(81 106)	(84 433)	(84 558)	(85 596)	(88 025)	(89 144)	(91 640)	(92 787)
Amortization of regulatory deferral accounts										
Power Smart programs	73 101	75 159	77 059	75 008	73 863	73 203	72 900	74 807	77 517	80 195
Conawapa Generation	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645
Affordable Energy Fund	97	95	-	-	-	-	-	-	-	-
Site restoration costs	1 826	1 724	1 514	1 334	1 046	891	616	433	295	188
Regulatory costs	1 749	1 789	1 821	1 866	1 900	1 947	1 982	2 031	2 068	2 120
Acquisition costs	692	692	692	678	300	300	199	6	-	-
Change in depreciation method	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862
Loss on disposal of assets	577	577	577	577	577	577	577	577	577	577
Deferred ineligible overhead	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090
Total amortization of regulatory deferral accounts	117 640	119 633	121 259	119 061	117 283	116 515	115 871	117 452	120 054	122 677
Total net movement in regulatory deferral balances	$ 44 804	$ 43 390	$ 40 154	$ 34 627	$ 32 724	$ 30 919	$ 27 846	$ 28 308	$ 28 413	$ 29 890
Year over year $ change	$ (3 670)	$ (1 414)	$ (3 236)	$ (5 526)	$ (1 903)	$ (1 805)	$ (3 073)	$ 462	$ 105	$ 1 477
Year over year % change	-8%	-3%	-7%	-14%	-5%	-6%	-10%	2%	0%	5%

Figure 2. Net Movement in Regulatory Deferral Accounts (MH16 Update with Interim)

MANITOBA HYDRO (Updated MH16)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS
(000's)

	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast
Additions of regulatory deferral accounts										
Power Smart programs	$ (50 453)	$ (57 184)	$ (99 404)	$ (94 251)	$ (88 857)	$ (86 929)	$ (66 549)	$ (60 271)	$ (62 350)	$ (66 576)
Conawapa Generation	-	-	-	(379 758)	-	-	-	-	-	-
Change in depreciation method	(31 386)	(33 952)	(39 506)	(42 869)	(44 702)	(47 924)	(56 279)	-	-	-
Deferred ineligible overhead	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	-	-	-
Loss on disposal of assets	(1 302)	-	-	-	-	-	-	-	-	-
Site restoration costs	(1 361)	(2 794)	(2 703)	(1 408)	(1 317)	(1 133)	(6)	-	-	-
Regulatory costs	(3 946)	(3 664)	(2 339)	(1 339)	(1 882)	(1 391)	(1 954)	(1 444)	(2 029)	(1 499)
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	(63)	-	-	-	-	-	-	-	-	-
Total additions of regulatory deferral accounts	(108 712)	(117 794)	(164 151)	(539 825)	(156 958)	(157 576)	(144 988)	(61 715)	(64 379)	(68 075)
Amortization of regulatory deferral accounts										
Power Smart programs	34 937	35 742	36 662	43 202	49 473	55 519	61 480	65 459	68 888	71 976
Conawapa Generation	-	-	-	11 592	12 645	12 645	12 645	12 645	12 645	12 645
Affordable Energy Fund	224	449	480	563	545	511	489	454	322	147
Site restoration costs	4 070	4 106	3 990	3 855	3 559	2 990	2 629	2 234	2 170	1 991
Regulatory costs	2 358	2 942	3 665	2 884	2 495	1 883	1 400	1 657	1 684	1 721
Acquisition costs	692	692	692	692	692	692	692	692	692	692
Change in depreciation method	-	-	-	6 437	9 345	11 534	13 850	16 455	17 862	17 862
Loss on disposal of assets	-	288	577	577	577	577	577	577	577	577
Deferred ineligible overhead	-	1 768	4 545	5 555	6 565	7 575	8 585	9 090	9 090	9 090
Total amortization of regulatory deferral accounts	42 281	45 986	50 611	75 357	85 894	93 926	102 347	109 263	113 930	116 700
Total net movement in regulatory deferral balances	$ (66 431)	$ (71 808)	$ (113 540)	$ (464 468)	$ (71 064)	$ (63 651)	$ (42 641)	$ 47 548	$ 49 551	$ 48 625
Year over year $ change		$ (5 377)	$ (41 732)	$ (350 928)	$393 404	$ 7 413	$ 21 010	$ 90 189	$ 2 003	$ (926)
Year over year % change		8%	58%	309%	-85%	-10%	-33%	-212%	4%	-2%

MANITOBA HYDRO (Updated MH16)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS
(000's)

	2026/27 Forecast	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Additions of regulatory deferral accounts										
Power Smart programs	$ (70 722)	$ (74 678)	$ (78 900)	$ (82 801)	$ (82 257)	$ (83 893)	$ (85 623)	$ (87 367)	$ (89 135)	$ (90 933)
Conawapa Generation	-	-	-	-	-	-	-	-	-	-
Change in depreciation method	-	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-	-
Regulatory costs	(2 114)	(1 564)	(2 206)	(1 632)	(2 302)	(1 703)	(2 402)	(1 777)	(2 506)	(1 854)
Acquisition costs	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-	-
Total additions of regulatory deferral accounts	(72 836)	(76 243)	(81 106)	(84 433)	(84 558)	(85 596)	(88 025)	(89 144)	(91 640)	(92 787)
Amortization of regulatory deferral accounts										
Power Smart programs	73 251	75 309	77 059	75 008	73 863	73 203	72 900	74 807	77 517	80 195
Conawapa Generation	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645
Affordable Energy Fund	97	95	-	-	-	-	-	-	-	-
Site restoration costs	1 826	1 724	1 514	1 334	1 046	891	616	433	295	188
Regulatory costs	1 749	1 789	1 821	1 866	1 900	1 947	1 982	2 031	2 068	2 120
Acquisition costs	692	692	692	678	300	300	199	6	-	-
Change in depreciation method	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862	17 862
Loss on disposal of assets	577	577	577	577	577	577	577	577	577	577
Deferred ineligible overhead	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090
Total amortization of regulatory deferral accounts	117 790	119 783	121 259	119 061	117 283	116 515	115 871	117 452	120 054	122 677
Total net movement in regulatory deferral balances	$ 44 955	$ 43 541	$ 40 154	$ 34 627	$ 32 724	$ 30 919	$ 27 846	$ 28 308	$ 28 413	$ 29 890
Year over year $ change	$ (3 670)	$ (1 414)	$ (3 387)	$ (5 526)	$ (1 903)	$ (1 805)	$ (3 073)	$ 462	$ 105	$ 1 477
Year over year % change	-8%	-3%	-8%	-14%	-5%	-6%	-10%	2%	0%	5%

REFERENCE:

Tab 6, Pages 42-43

PREAMBLE TO IR (IF ANY):

QUESTION:

c) For each of IFF16 and MH16 Updated for the 20 year forecasts, please provide a schedule showing the regulatory deferral balances by year (asset and liability) showing all transactions for the year including transfers, amortizations, etc. to derive the annual balance sheet values.

RATIONALE FOR QUESTION:

RESPONSE:

Table 1 and 2 below provide a continuity schedule for the MH16 regulatory deferral debit and credit balances, respectively, from 2016/17 to 2035/36. Table 3 and 4 reflect the same for the MH16 Update with the Interim.

TABLE 1: MH16 REGULATORY DEFERRAL DEBIT BALANCE

in thousands of dollars

	2016/17 Outlook	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of regulatory deferral debit balance											
Power Smart programs	$ 188 873	$ 204 079	$ 224 016	$ 286 909	$ 338 108	$ 377 643	$ 409 204	$ 414 423	$ 409 386	$ 402 999	$ 397 750
Change in depreciation method	59 441	92 002	123 229	155 450	188 974	222 142	256 217	296 042	278 180	260 318	242 456
Deferred ineligible overhead	40 400	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938
Loss on disposal of assets	8 339	11 539	11 250	10 673	10 096	9 520	8 943	8 366	7 789	7 212	6 635
Site restoration costs	30 710	28 028	26 716	25 428	22 982	20 740	18 883	16 260	14 025	11 855	9 864
Regulatory costs	3 821	5 486	6 209	4 882	3 338	2 725	2 233	2 787	2 573	2 919	2 697
Acquisition costs	10 480	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560
Affordable Energy Fund	4 324	3 619	3 169	2 689	2 126	1 581	1 071	581	128	(195)	(342)
Conawapa Generation	-	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	389 987	458 742	526 319	632 724	1 094 434	1 163 460	1 224 945	1 265 132	1 216 328	1 166 927	1 118 453
Additions to regulatory deferral debit balance											
Power Smart programs	$ 50 143	$ 55 678	$ 99 404	$ 94 251	$ 88 857	$ 86 929	$ 66 549	$ 60 271	$ 62 350	$ 66 576	$ 70 722
Change in depreciation method	32 562	33 952	39 506	42 869	44 702	47 924	56 279	-	-	-	-
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-	-
Loss on disposal of assets	3 200	-	-	-	-	-	-	-	-	-	-
Site restoration costs	1 424	2 794	2 703	1 408	1 317	1 133	6	-	-	-	-
Regulatory costs	4 389	3 664	2 339	1 339	1 882	1 391	1 954	1 444	2 029	1 499	2 114
Acquisition costs	-	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	379 758	-	-	-	-	-	-	-
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	111 918	116 288	164 151	539 825	156 958	157 576	144 988	61 715	64 379	68 075	72 836
Amortization of regulatory deferral debit balance											
Power Smart programs	$ (34 937)	$ (35 742)	$ (36 512)	$ (43 052)	$ (49 322)	$ (55 368)	$ (61 329)	$ (65 308)	$ (68 737)	$ (71 825)	$ (73 101)
Change in depreciation method	-	(2 724)	(7 285)	(9 345)	(11 534)	(13 850)	(16 455)	(17 862)	(17 862)	(17 862)	(17 862)
Deferred ineligible overhead	-	(1 768)	(4 545)	(5 555)	(6 565)	(7 575)	(8 585)	(9 090)	(9 090)	(9 090)	(9 090)
Loss on disposal of assets	-	(288)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)
Site restoration costs	(4 106)	(4 106)	(3 990)	(3 855)	(3 559)	(2 990)	(2 629)	(2 234)	(2 170)	(1 991)	(1 826)
Regulatory costs	(2 723)	(2 942)	(3 665)	(2 884)	(2 495)	(1 883)	(1 400)	(1 657)	(1 684)	(1 721)	(1 749)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)
Affordable Energy Fund	(705)	(449)	(480)	(563)	(545)	(511)	(489)	(454)	(322)	(147)	(97)
Conawapa Generation	-	-	-	(11 592)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	(43 163)	(48 711)	(57 746)	(78 114)	(87 933)	(96 091)	(104 801)	(110 520)	(113 780)	(116 550)	(117 640)
Closing balance of regulatory deferral debit balance											
Power Smart programs	$ 204 079	$ 224 016	$ 286 909	$ 338 108	$ 377 643	$ 409 204	$ 414 423	$ 409 386	$ 402 999	$ 397 750	$ 395 371
Change in depreciation method	92 002	123 229	155 450	188 974	222 142	256 217	296 042	278 180	260 318	242 456	224 595
Deferred ineligible overhead	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938	110 848
Loss on disposal of assets	11 539	11 250	10 673	10 096	9 520	8 943	8 366	7 789	7 212	6 635	6 058
Site restoration costs	28 028	26 716	25 428	22 982	20 740	18 883	16 260	14 025	11 855	9 864	8 038
Regulatory costs	5 486	6 209	4 882	3 338	2 725	2 233	2 787	2 573	2 919	2 697	3 062
Acquisition costs	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560	2 868
Affordable Energy Fund	3 619	3 169	2 689	2 126	1 581	1 071	581	128	(195)	(342)	(439)
Conawapa Generation	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294	279 649
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	458 742	**526 319**	**632 724**	**1 094 434**	**1 163 460**	**1 224 945**	**1 265 132**	**1 216 328**	**1 166 927**	**1 118 453**	**1 073 649**

TABLE 1: MH16 REGULATORY DEFERRAL DEBIT BALANCE

in thousands of dollars

	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of regulatory deferral debit balance									
Power Smart programs	$ 395 371	$ 394 890	$ 396 731	$ 404 524	$ 412 917	$ 423 607	$ 436 331	$ 448 890	$ 460 508
Change in depreciation method	224 595	206 733	188 871	171 010	153 148	135 286	117 424	99 563	81 701
Deferred ineligible overhead	110 848	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128
Loss on disposal of assets	6 058	5 481	4 904	4 327	3 750	3 173	2 596	2 019	1 442
Site restoration costs	8 038	6 314	4 800	3 466	2 420	1 529	912	479	184
Regulatory costs	3 062	2 838	3 222	2 989	3 391	3 147	3 566	3 312	3 750
Acquisition costs	2 868	2 176	1 484	806	506	206	7	1	1
Affordable Energy Fund	(439)	(534)	(534)	(534)	(534)	(534)	(534)	(534)	(534)
Conawapa Generation	279 649	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	1 073 649	1 030 259	990 105	955 478	922 753	891 834	863 988	835 679	807 266
Additions to regulatory deferral debit balance									
Power Smart programs	$ 74 678	$ 78 900	$ 82 801	$ 82 257	$ 83 893	$ 85 623	$ 87 367	$ 89 135	$ 90 933
Change in depreciation method	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-
Regulatory costs	1 564	2 206	1 632	2 302	1 703	2 402	1 777	2 506	1 854
Acquisition costs	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	-	-	-	-	-	-
DSM deferral	-	-	-	-	-	-	-	-	-
	76 243	81 106	84 433	84 558	85 596	88 025	89 144	91 640	92 787
Amortization of regulatory deferral debit balance									
Power Smart programs	$ (75 159)	$ (77 059)	$ (75 008)	$ (73 863)	$ (73 203)	$ (72 900)	$ (74 807)	$ (77 517)	$ (80 195)
Change in depreciation method	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)
Deferred ineligible overhead	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)
Loss on disposal of assets	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)
Site restoration costs	(1 724)	(1 514)	(1 334)	(1 046)	(891)	(616)	(433)	(295)	(188)
Regulatory costs	(1 789)	(1 821)	(1 866)	(1 900)	(1 947)	(1 982)	(2 031)	(2 068)	(2 120)
Acquisition costs	(692)	(692)	(678)	(300)	(300)	(199)	(6)	-	-
Affordable Energy Fund	(95)	-	-	-	-	-	-	-	-
Conawapa Generation	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)
DSM deferral	-	-	-	-	-	-	-	-	-
	(119 633)	(121 259)	(119 061)	(117 283)	(116 515)	(115 871)	(117 452)	(120 054)	(122 677)
Closing balance of regulatory deferral debit balance									
Power Smart programs	$ 394 890	$ 396 731	$ 404 524	$ 412 917	$ 423 607	$ 436 331	$ 448 890	$ 460 508	$ 471 246
Change in depreciation method	206 733	188 871	171 010	153 148	135 286	117 424	99 563	81 701	63 839
Deferred ineligible overhead	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128	29 038
Loss on disposal of assets	5 481	4 904	4 327	3 750	3 173	2 596	2 019	1 442	866
Site restoration costs	6 314	4 800	3 466	2 420	1 529	912	479	184	(4)
Regulatory costs	2 838	3 222	2 989	3 391	3 147	3 566	3 312	3 750	3 484
Acquisition costs	2 176	1 484	806	506	206	7	1	1	1
Affordable Energy Fund	(534)	(534)	(534)	(534)	(534)	(534)	(534)	(534)	(534)
Conawapa Generation	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486	165 840
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	1 030 259	**990 105**	**955 478**	**922 753**	**891 834**	**863 988**	**835 679**	**807 266**	**777 376**

TABLE 2: MH16 REGULATORY DEFERRAL CREDIT BALANCE *in thousands of dollars*	2016/17 Outlook	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of regulatory deferral credit balance											
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
Additions to regulatory deferral credit balance											
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Amortization of regulatory deferral credit balance											
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Closing balance of regulatory deferral credit balance											
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	43 600	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**

TABLE 2: MH16 REGULATORY DEFERRAL CREDIT BALANCE *in thousands of dollars*	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of regulatory deferral credit balance									
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
Additions to regulatory deferral credit balance									
DSM deferral	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Amortization of regulatory deferral credit balance									
DSM deferral	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Closing balance of regulatory deferral credit balance									
DSM deferral	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600	43 600
	43 600	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**	**43 600**

TABLE 3: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL DEBIT BALANCE

in thousands of dollars

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Opening balance of regulatory deferral debit balance											
Power Smart programs	$ 188 873	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361
Change in depreciation method	59 441	90 827	124 778	164 284	200 716	236 074	272 464	314 894	298 439	280 577	262 716
Deferred ineligible overhead	40 400	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938
Loss on disposal of assets	8 339	9 641	9 352	8 775	8 198	7 622	7 045	6 468	5 891	5 314	4 737
Site restoration costs	30 710	28 001	26 689	25 401	22 954	20 712	18 855	16 232	13 998	11 828	9 837
Regulatory costs	3 821	5 409	6 131	4 805	3 260	2 648	2 155	2 709	2 496	2 841	2 620
Acquisition costs	10 480	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560
Affordable Energy Fund	4 324	4 163	3 714	3 234	2 670	2 126	1 615	1 126	672	350	203
Conawapa Generation	-	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294
DSM deferral	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	389 987	461 617	533 425	646 965	1 111 433	1 182 497	1 246 148	1 288 788	1 241 241	1 191 690	1 143 065
Additions to regulatory deferral debit balance											
Power Smart programs	$ 50 453	$ 57 184	$ 99 404	$ 94 251	$ 88 857	$ 86 929	$ 66 549	$ 60 271	$ 62 350	$ 66 576	$ 70 722
Change in depreciation method	31 386	33 952	39 506	42 869	44 702	47 924	56 279	-	-	-	-
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-	-
Loss on disposal of assets	1 302	-	-	-	-	-	-	-	-	-	-
Site restoration costs	1 361	2 794	2 703	1 408	1 317	1 133	6	-	-	-	-
Regulatory costs	3 946	3 664	2 339	1 339	1 882	1 391	1 954	1 444	2 029	1 499	2 114
Acquisition costs	-	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	63	-	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	379 758	-	-	-	-	-	-	-
DSM deferral	5 200	-	-	-	-	-	-	-	-	-	-
	113 912	117 794	164 151	539 825	156 958	157 576	144 988	61 715	64 379	68 075	72 836
Amortization of regulatory deferral debit balance											
Power Smart programs	$ (34 937)	$ (35 742)	$ (36 662)	$ (43 202)	$ (49 473)	$ (55 519)	$ (61 480)	$ (65 459)	$ (68 888)	$ (71 976)	$ (73 251)
Change in depreciation method	-	-	-	(6 437)	(9 345)	(11 534)	(13 850)	(16 455)	(17 862)	(17 862)	(17 862)
Deferred ineligible overhead	-	(1 768)	(4 545)	(5 555)	(6 565)	(7 575)	(8 585)	(9 090)	(9 090)	(9 090)	(9 090)
Loss on disposal of assets	-	(288)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)
Site restoration costs	(4 070)	(4 106)	(3 990)	(3 855)	(3 559)	(2 990)	(2 629)	(2 234)	(2 170)	(1 991)	(1 826)
Regulatory costs	(2 358)	(2 942)	(3 665)	(2 884)	(2 495)	(1 883)	(1 400)	(1 657)	(1 684)	(1 721)	(1 749)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)	(692)
Affordable Energy Fund	(224)	(449)	(480)	(563)	(545)	(511)	(489)	(454)	(322)	(147)	(97)
Conawapa Generation	-	-	-	(11 592)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	(42 281)	(45 987)	(50 612)	(75 357)	(85 894)	(93 926)	(102 347)	(109 263)	(113 930)	(116 700)	(117 790)
Closing balance of regulatory deferral debit balance											
Power Smart programs	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361	$ 395 831
Change in depreciation method	90 827	124 778	164 284	200 716	236 074	272 464	314 894	298 439	280 577	262 716	244 854
Deferred ineligible overhead	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938	110 848
Loss on disposal of assets	9 641	9 352	8 775	8 198	7 622	7 045	6 468	5 891	5 314	4 737	4 160
Site restoration costs	28 001	26 689	25 401	22 954	20 712	18 855	16 232	13 998	11 828	9 837	8 011
Regulatory costs	5 409	6 131	4 805	3 260	2 648	2 155	2 709	2 496	2 841	2 620	2 985
Acquisition costs	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560	2 868
Affordable Energy Fund	4 163	3 714	3 234	2 670	2 126	1 615	1 126	672	350	203	106
Conawapa Generation	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294	279 649
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	461 617	**533 425**	**646 965**	**1 111 433**	**1 182 497**	**1 246 148**	**1 288 788**	**1 241 241**	**1 191 690**	**1 143 065**	**1 098 110**

TABLE 3: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL DEBIT BALANCE

in thousands of dollars

	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of regulatory deferral debit balance									
Power Smart programs	$ 395 831	$ 395 200	$ 397 041	$ 404 833	$ 413 227	$ 423 916	$ 436 640	$ 449 200	$ 460 818
Change in depreciation method	244 854	226 992	209 130	191 269	173 407	155 545	137 684	119 822	101 960
Deferred ineligible overhead	110 848	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128
Loss on disposal of assets	4 160	3 583	3 006	2 429	1 852	1 275	698	121	(456)
Site restoration costs	8 011	6 286	4 773	3 439	2 393	1 502	885	452	157
Regulatory costs	2 985	2 760	3 145	2 911	3 313	3 070	3 489	3 235	3 672
Acquisition costs	2 868	2 176	1 484	806	506	206	7	1	1
Affordable Energy Fund	106	11	11	11	11	11	11	11	11
Conawapa Generation	279 649	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	1 098 110	1 054 570	1 014 416	979 788	947 064	916 145	888 298	859 990	831 577
Additions to regulatory deferral debit balance									
Power Smart programs	$ 74 678	$ 78 900	$ 82 801	$ 82 257	$ 83 893	$ 85 623	$ 87 367	$ 89 135	$ 90 933
Change in depreciation method	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-
Regulatory costs	1 564	2 206	1 632	2 302	1 703	2 402	1 777	2 506	1 854
Acquisition costs	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	-	-	-	-	-	-
DSM deferral	-	-	-	-	-	-	-	-	-
	76 243	81 106	84 433	84 558	85 596	88 025	89 144	91 640	92 787
Amortization of regulatory deferral debit balance									
Power Smart programs	$ (75 309)	$ (77 059)	$ (75 008)	$ (73 863)	$ (73 203)	$ (72 900)	$ (74 807)	$ (77 517)	$ (80 195)
Change in depreciation method	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)	(17 862)
Deferred ineligible overhead	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)	(9 090)
Loss on disposal of assets	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)	(577)
Site restoration costs	(1 724)	(1 514)	(1 334)	(1 046)	(891)	(616)	(433)	(295)	(188)
Regulatory costs	(1 789)	(1 821)	(1 866)	(1 900)	(1 947)	(1 982)	(2 031)	(2 068)	(2 120)
Acquisition costs	(692)	(692)	(678)	(300)	(300)	(199)	(6)	-	-
Affordable Energy Fund	(95)	-	-	-	-	-	-	-	-
Conawapa Generation	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)	(12 645)
DSM deferral	-	-	-	-	-	-	-	-	-
	(119 783)	(121 259)	(119 061)	(117 283)	(116 515)	(115 871)	(117 452)	(120 054)	(122 677)
Closing balance of regulatory deferral debit balance									
Power Smart programs	$ 395 200	$ 397 041	$ 404 833	$ 413 227	$ 423 916	$ 436 640	$ 449 200	$ 460 818	$ 471 556
Change in depreciation method	226 992	209 130	191 269	173 407	155 545	137 684	119 822	101 960	84 098
Deferred ineligible overhead	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128	29 038
Loss on disposal of assets	3 583	3 006	2 429	1 852	1 275	698	121	(456)	(1 032)
Site restoration costs	6 286	4 773	3 439	2 393	1 502	885	452	157	(31)
Regulatory costs	2 760	3 145	2 911	3 313	3 070	3 489	3 235	3 672	3 407
Acquisition costs	2 176	1 484	806	506	206	7	1	1	1
Affordable Energy Fund	11	11	11	11	11	11	11	11	11
Conawapa Generation	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486	165 840
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	1 054 570	**1 014 416**	**979 788**	**947 064**	**916 145**	**888 298**	**859 990**	**831 577**	**801 687**

TABLE 4: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL CREDIT BALANCE

in thousands of dollars

	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of regulatory deferral credit balance											
DSM deferral	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
Additions to regulatory deferral credit balance											
DSM deferral	5 200	-	-	-	-	-	-	-	-	-	-
	5 200	-	-	-	-	-	-	-	-	-	-
Amortization of regulatory deferral credit balance											
DSM deferral	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
Closing balance of regulatory deferral credit balance											
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	48 800	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**

TABLE 4: MH16 UPDATE WITH INTERIM REGULATORY DEFERRAL CREDIT BALANCE *in thousands of dollars*	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of regulatory deferral credit balance									
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
Additions to regulatory deferral credit balance									
DSM deferral	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Amortization of regulatory deferral credit balance									
DSM deferral	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-
Closing balance of regulatory deferral credit balance									
DSM deferral	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
	48 800	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**	**48 800**

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REFERENCE:

Appendix 3.1, 3.3, MH exhibit, MIPUG MFR5

PREAMBLE TO IR (IF ANY):

MH has made changes in its financial forecast presentation that is consistent with Financial Reporting under IFRS. To have a continuity of presentation with past GRA's for rate setting purposes.

QUESTION:

a) Please provide an update to tab 6 figure 6.30 extending it to 2027 and include the opening and closing balances of the related regulatory deferral balances by item.

b) Please provide an update to MIPUG MFR5 based on prior presentation of Attachment 28 (2016 Interim) (without the net movement in regulatory deferral accounts broken out.) Please include the 2016/17 year.

c) Please refile MH16 Updated in format (a) under the assumption that the restructuring charge is expensed fully in 2016/17, the year the plan was announced.

d) Please refile MH16 Update consistent with part (b) assuming the request to recover the difference between ELG & ASL as a regulatory asset is denied.

e) Please provide an update to MIPUG MFR5 based on prior presentation of Attachment 46 scenario 1.

f) Please provide in the same format as (b) an update based on IFF15 3.95% rate increases. (appendix 3.4)

RATIONALE FOR QUESTION:

RESPONSE:

a) The following table provides the extended Figure 6.30 outlining Net Movement in Regulatory Deferral Accounts based on MH16 Update with the Interim.

	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast
Opening balance of net regulatory deferral								
Power Smart programs	$ 168 084	$ 167 983	$ 188 873	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007
Change in depreciation method	-	28 466	59 441	90 827	124 778	164 284	200 716	236 074
Deferred ineligible overhead	-	20 200	40 400	60 600	79 033	94 688	109 333	122 968
Loss on disposal of assets	-	5 527	8 339	9 641	9 352	8 775	8 198	7 622
Site restoration costs	32 790	31 306	30 710	28 001	26 689	25 401	22 954	20 712
Regulatory costs	102	1 113	3 821	5 409	6 131	4 805	3 260	2 648
Acquisition costs	18 661	11 172	10 480	9 788	9 096	8 404	7 712	7 020
Affordable Energy Fund	11 278	6 279	4 324	4 163	3 714	3 234	2 670	2 126
Conawapa Generation	-	-	-	-	-	-	368 166	355 521
DSM deferral debit balance	16 300	16 300	43 600	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(16 300)	(16 300)	(43 600)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	230 915	272 046	346 387	412 817	484 625	598 165	1 062 633	1 133 697
Additions to regulatory deferral accounts								
Power Smart programs	$ (31 475)	$ (53 816)	$ (50 453)	$ (57 184)	$ (99 404)	$ (94 251)	$ (88 857)	$ (86 929)
Change in depreciation method	(28 466)	(30 975)	(31 386)	(33 952)	(39 506)	(42 869)	(44 702)	(47 924)
Deferred ineligible overhead	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)
Loss on disposal of assets	(5 527)	(2 812)	(1 302)	-	-	-	-	-
Site restoration costs	(2 359)	(3 371)	(1 361)	(2 794)	(2 703)	(1 408)	(1 317)	(1 133)
Regulatory costs	(1 038)	(3 949)	(3 946)	(3 664)	(2 339)	(1 339)	(1 882)	(1 391)
Acquisition costs	6 355	-	-	-	-	-	-	-
Affordable Energy Fund	(168)	(66)	(63)	-	-	-	-	-
Conawapa Generation	-	-	-	-	-	(379 758)	-	-
DSM deferral debit balance	-	(27 300)	(5 200)	-	-	-	-	-
DSM deferral credit balance	-	27 300	5 200	-	-	-	-	-
	(82 877)	(115 190)	(108 712)	(117 794)	(164 151)	(539 825)	(156 958)	(157 576)
Amortization of regulatory deferral accounts								
Power Smart programs	$ 31 576	$ 32 927	$ 34 937	$ 35 742	$ 36 662	$ 43 202	$ 49 473	$ 55 519
Change in depreciation method	-	-	-	-	-	6 437	9 345	11 534
Deferred ineligible overhead	-	-	-	1 768	4 545	5 555	6 565	7 575
Loss on disposal of assets	-	-	-	288	577	577	577	577
Site restoration costs	3 842	3 967	4 070	4 106	3 990	3 855	3 559	2 990
Regulatory costs	27	1 241	2 358	2 942	3 665	2 884	2 495	1 883
Acquisition costs	1 134	692	692	692	692	692	692	692
Affordable Energy Fund	5 167	2 021	224	449	480	563	545	511
Conawapa Generation	-	-	-	-	-	11 592	12 645	12 645
DSM deferral debit balance	-	-	-	-	-	-	-	-
DSM deferral credit balance	-	-	-	-	-	-	-	-
	41 746	40 848	42 281	45 987	50 612	75 357	85 894	93 926

	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast
Closing balance of net regulatory deferral								
Power Smart programs	$ 167 983	$ 188 873	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417
Change in depreciation method	28 466	59 441	90 827	124 778	164 284	200 716	236 074	272 464
Deferred ineligible overhead	20 200	40 400	60 600	79 033	94 688	109 333	122 968	135 593
Loss on disposal of assets	5 527	8 339	9 641	9 352	8 775	8 198	7 622	7 045
Site restoration costs	31 306	30 710	28 001	26 689	25 401	22 954	20 712	18 855
Regulatory costs	1 113	3 821	5 409	6 131	4 805	3 260	2 648	2 155
Acquisition costs	11 172	10 480	9 788	9 096	8 404	7 712	7 020	6 328
Affordable Energy Fund	6 279	4 324	4 163	3 714	3 234	2 670	2 126	1 615
Conawapa Generation	-	-	-	-	-	368 166	355 521	342 875
DSM deferral debit balance	16 300	43 600	48 800	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(16 300)	(43 600)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	272 046	**346 387**	**412 817**	**484 625**	**598 165**	**1 062 633**	**1 133 697**	**1 197 348**
Total net movement in regulatory deferral balances	**(41 131)**	**(74 342)**	**(66 431)**	**(71 808)**	**(113 540)**	**(464 468)**	**(71 064)**	**(63 651)**
Year over year $ change		$ (33 211)	$ 7 910	$ (5 377)	$ (41 731)	$ (350 928)	$ 393 404	$ 7 413
Year over year % change		81%	-11%	8%	58%	309%	-85%	-10%

	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of net regulatory deferral					
Power Smart programs	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361
Change in depreciation method	272 464	314 894	298 439	280 577	262 716
Deferred ineligible overhead	135 593	147 208	138 118	129 028	119 938
Loss on disposal of assets	7 045	6 468	5 891	5 314	4 737
Site restoration costs	18 855	16 232	13 998	11 828	9 837
Regulatory costs	2 155	2 709	2 496	2 841	2 620
Acquisition costs	6 328	5 636	4 944	4 252	3 560
Affordable Energy Fund	1 615	1 126	672	350	203
Conawapa Generation	342 875	330 230	317 585	304 939	292 294
DSM deferral debit balance	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	1 197 348	1 239 988	1 192 441	1 142 890	1 094 265
Additions to regulatory deferral accounts					
Power Smart programs	$ (66 549)	$ (60 271)	$ (62 350)	$ (66 576)	$ (70 722)
Change in depreciation method	(56 279)	-	-	-	-
Deferred ineligible overhead	(20 200)	-	-	-	-
Loss on disposal of assets	-	-	-	-	-
Site restoration costs	(6)	-	-	-	-
Regulatory costs	(1 954)	(1 444)	(2 029)	(1 499)	(2 114)
Acquisition costs	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-
Conawapa Generation	-	-	-	-	-
DSM deferral debit balance	-	-	-	-	-
DSM deferral credit balance	-	-	-	-	-
	(144 988)	(61 715)	(64 379)	(68 075)	(72 836)
Amortization of regulatory deferral accounts					
Power Smart programs	$ 61 480	$ 65 459	$ 68 888	$ 71 976	$ 73 251
Change in depreciation method	13 850	16 455	17 862	17 862	17 862
Deferred ineligible overhead	8 585	9 090	9 090	9 090	9 090
Loss on disposal of assets	577	577	577	577	577
Site restoration costs	2 629	2 234	2 170	1 991	1 826
Regulatory costs	1 400	1 657	1 684	1 721	1 749
Acquisition costs	692	692	692	692	692
Affordable Energy Fund	489	454	322	147	97
Conawapa Generation	12 645	12 645	12 645	12 645	12 645
DSM deferral debit balance	-	-	-	-	-
DSM deferral credit balance	-	-	-	-	-
	102 347	109 263	113 930	116 700	117 790

	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Closing balance of net regulatory deferral					
Power Smart programs	$ 415 486	$ 410 298	$ 403 760	$ 398 361	$ 395 831
Change in depreciation method	314 894	298 439	280 577	262 716	244 854
Deferred ineligible overhead	147 208	138 118	129 028	119 938	110 848
Loss on disposal of assets	6 468	5 891	5 314	4 737	4 160
Site restoration costs	16 232	13 998	11 828	9 837	8 011
Regulatory costs	2 709	2 496	2 841	2 620	2 985
Acquisition costs	5 636	4 944	4 252	3 560	2 868
Affordable Energy Fund	1 126	672	350	203	106
Conawapa Generation	330 230	317 585	304 939	292 294	279 649
DSM deferral debit balance	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	1 239 988	**1 192 441**	**1 142 890**	**1 094 265**	**1 049 310**
Total net movement in regulatory deferral balances	**(42 641)**	**47 548**	**49 551**	**48 625**	**44 955**
Year over year $ change	$ 21 010	$ 90 189	$ 2 003	$ (926)	$ (3 670)
Year over year % change	-33%	-212%	4%	-2%	-8%

b) As discussed in MIPUG MFR 5, Manitoba Hydro has the following concerns with respect to a scenario based on Attachment 28:

1. Substantial growth in regulatory deferral accounts results in intergenerational inequity and poses a risk to rate stability for future ratepayers in the event of the occurrence of adverse risks such as drought and/or higher interest rates.
2. Although changes in amortization periods can result in improvements to net income and retained earnings, such changes do not result in an improvement in the corporation's cash position, which is key to sustaining and improving the financial strength of Manitoba Hydro.

Manitoba Hydro is not readily able to provide financial statements which are in the former presentation format, as this presentation format is not compliant with IFRS and is no longer used by the corporation. The Public Sector Accounting Board standards requires that public-sector enterprises with self-sustaining commercial-type operations (government business enterprises) such as Manitoba Hydro follow IFRS.

In order to respond to part b) of this question, Manitoba Hydro is providing below Scenario 1 from Attachment 28 of the 2016/17 Supplemental Filing in the IFRS-compliant presentation and based on MH15 (page 8 to 13 of this response).

In addition and notwithstanding the concerns outlined above, Manitoba Hydro is providing below financial statements reflecting Scenario 1 from Attachment 28 updated to reflect MH16 Update with Interim (page 14 to 19 of this response). Please note that the 2016/17 year represents actual results and has, therefore, not been adjusted to reflect the assumptions in Attachment 28.

The table below outlines the accounting treatment in MH16 Update with Interim, and the assumptions in part b, of this response.

	MH16 UPDATE WITH INTERIM	**PUB/MH I-1 PART (B)**
INELIGIBLE OVERHEAD		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferred Until	2022/23	Indefinite
EQUAL LIFE GROUP (ELG)/AVERAGE SERVICE LIFE (ASL)		
ELG/ASL Amortization Period	20 years	34 years (2.98%)
ELG/ASL Deferred Until	2022/23	Indefinite

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
IFRS Compliant Statements
Financial Information MFR #1 -Scenario 1
(In Millions of Dollars)

For the year ended March 31	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
REVENUES										
General Consumers										
at approved rates	1 517	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610
additional*	0	61	125	191	258	335	411	493	580	672
BPIII Reserve Account	(54)	(67)	(69)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	118	119	32	32	33
	1 887	1 985	2 086	2 225	2 465	2 844	3 066	3 087	3 191	3 301
EXPENSES										
Operating and Administrative	542	552	557	571	585	601	607	619	631	644
Finance Expense	566	589	579	716	824	1 079	1 189	1 182	1 182	1 177
Depreciation and Amortization	367	383	398	472	521	617	663	677	691	707
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	108	123	137	146	148	151	158	159	166	168
Other Expenses	88	66	104	98	95	95	100	77	69	74
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 926	1 987	2 079	2 304	2 470	2 881	3 079	3 081	3 110	3 152
Net Income before Net Movement in Reg. Deferral	(39)	(2)	7	(79)	(5)	(37)	(14)	6	80	149
Net Movement in Regulatory Deferral	92	70	99	86	78	78	79	48	36	35
Net Income	54	68	106	7	73	41	66	54	116	185
Net Income Attributable to:										
Manitoba Hydro	**63**	**77**	**110**	**10**	**73**	**44**	**64**	**51**	**111**	**182**
Non-controlling Interest	(10)	(9)	(4)	(3)	(0)	(2)	1	3	5	3
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	16%	14%	15%	14%	14%	14%	13%	13%	14%	15%
Interest Coverage	1.09	1.09	1.11	1.01	1.07	1.04	1.05	1.04	1.09	1.15
EBITDA Interest Coverage	1.60	1.54	1.54	1.48	1.56	1.59	1.64	1.65	1.72	1.80
Capital Coverage	0.98	0.98	1.20	1.05	1.06	1.12	1.32	1.48	1.58	1.60

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
IFRS Compliant Statements
Financial Information MFR #1 -Scenario 1
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES										
General Consumers										
at approved rates	1 626	1 641	1 655	1 669	1 683	1 706	1 734	1 763	1 795	1 831
additional*	769	872	979	1 093	1 158	1 231	1 311	1 395	1 485	1 581
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3 313	3 450	3 545	3 684	3 772	3 838	3 919	4 004	4 101	4 240
EXPENSES										
Operating and Administrative	657	669	683	697	706	719	733	748	763	778
Finance Expense	1 168	1 158	1 135	1 115	1 089	1 057	995	965	931	896
Depreciation and Amortization	723	739	753	767	780	793	806	820	837	854
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	169	170	172	173	175	176	178	180	182	184
Other Expenses	81	84	92	100	99	105	110	112	118	123
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3 169	3 203	3 216	3 242	3 246	3 243	3 224	3 234	3 252	3 293
Net Income before Net Movement in Reg. Deferral	144	246	329	442	526	595	695	770	849	947
Net Movement in Regulatory Deferral	37	38	42	50	49	53	56	56	58	57
Net Income	181	284	372	492	575	648	751	827	907	1 004
Net Income Attributable to:										
Manitoba Hydro	**180**	**282**	**368**	**486**	**566**	**637**	**737**	**810**	**888**	**984**
Non-controlling Interest	1	2	4	5	8	11	14	16	19	20
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	68.78%	72.15%	75.60%	79.11%	82.69%	86.35%
Financial Ratios										
Equity	15%	16%	18%	20%	22%	25%	27%	31%	34%	37%
Interest Coverage	1.15	1.24	1.32	1.43	1.52	1.60	1.73	1.83	1.94	2.08
EBITDA Interest Coverage	1.82	1.93	2.04	2.18	2.29	2.41	2.61	2.75	2.92	3.12
Capital Coverage	1.60	1.78	1.90	2.02	2.21	2.19	2.34	2.44	2.53	2.44

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
IFRS Compliant Statements
Financial Information MFR #1 -Scenario 1
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ASSETS										
Plant in Service	12 702	13 384	14 151	19 119	22 740	27 521	28 289	28 981	29 672	30 356
Accumulated Depreciation	(697)	(1 056)	(1 428)	(1 871)	(2 352)	(2 926)	(3 543)	(4 171)	(4 818)	(5 470)
Net Plant in Service	12 005	12 328	12 723	17 248	20 388	24 595	24 746	24 810	24 855	24 886
Construction in Progress	4 880	7 548	9 242	6 227	4 001	192	242	223	179	181
Current and Other Assets	2 391	2 652	2 909	3 079	3 084	2 809	2 202	2 371	2 629	2 613
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Total Assets before Reg. Deferral Debit Balance	19 513	22 815	25 269	27 117	28 147	28 548	28 106	28 284	28 509	28 493
Regulatory Deferral Debit Balance	375	445	949	1 034	1 112	1 191	1 270	1 319	1 355	1 390
	19 888	23 260	26 218	28 151	29 260	29 739	29 376	29 603	29 864	29 883
LIABILITIES AND EQUITY										
Long-Term Debt	14 487	17 586	19 499	21 929	22 429	22 808	22 963	23 257	23 237	22 725
Current and Other Liabilities	2 889	3 005	3 583	2 962	3 499	3 547	3 019	2 885	3 040	3 374
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	239	260	174	87	-	-	-	-
Retained Earnings	2 709	2 786	2 896	2 906	2 980	3 023	3 087	3 139	3 249	3 431
Accumulated Other Comprehensive Income	(771)	(780)	(512)	(438)	(388)	(305)	(285)	(282)	(282)	(281)
	19 888	23 260	26 218	28 151	29 260	29 739	29 376	29 603	29 864	29 883

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
IFRS Compliant Statements
Financial Information MFR #1 -Scenario 1
(In Millions of Dollars)

For the year ended March 31	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
ASSETS										
Plant in Service	31 081	31 760	32 474	33 199	33 909	34 645	35 389	36 152	36 984	37 813
Accumulated Depreciation	(6 141)	(6 818)	(7 513)	(8 216)	(8 936)	(9 677)	(10 405)	(11 151)	(11 930)	(12 671)
Net Plant in Service	24 941	24 942	24 961	24 983	24 973	24 968	24 984	25 001	25 054	25 142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2 659	3 163	3 568	4 024	4 551	4 522	5 286	6 086	6 958	7 770
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Total Assets before Reg. Deferral Debit Balance	28 527	29 025	29 409	29 846	30 319	30 268	31 005	31 787	32 687	33 672
Regulatory Deferral Debit Balance	1 427	1 465	1 508	1 558	1 607	1 660	1 716	1 773	1 830	1 888
	29 954	30 491	30 917	31 404	31 926	31 928	32 721	33 560	34 517	35 560
LIABILITIES AND EQUITY										
Long-Term Debt	23 293	23 495	23 437	23 360	22 632	22 622	22 625	22 619	22 622	20 941
Current and Other Liabilities	2 683	2 721	2 824	2 890	3 560	2 921	2 960	2 982	3 032	4 758
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3 612	3 894	4 262	4 748	5 314	5 951	6 688	7 499	8 387	9 370
Accumulated Other Comprehensive Income	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
	29 954	30 491	30 917	31 404	31 926	31 928	32 721	33 560	34 517	35 560

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
IFRS Compliant Statements
Financial Information MFR #1 -Scenario 1
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 974	2 041	2 145	2 235	2 367	2 745	2 966	3 074	3 178	3 288
Cash Paid to Suppliers and Employees	(856)	(899)	(945)	(964)	(977)	(1 036)	(1 067)	(1 090)	(1 112)	(1 137)
Interest Paid	(561)	(547)	(554)	(716)	(831)	(1 085)	(1 184)	(1 156)	(1 164)	(1 163)
Interest Received	9	3	11	19	22	19	17	2	2	5
	567	598	657	574	581	644	732	830	904	993
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 457	3 370	2 970	2 800	1 390	1 190	600	580	380	190
Sinking Fund Withdrawals	114	62	-	244	194	296	754	174	16	293
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	2 292	3 078	2 605	2 014	1 220	505	556	246	56	22
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 614)	(3 437)	(3 085)	(2 211)	(1 645)	(1 149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(220)	(247)	(271)	(328)	(202)	(246)	(259)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2 768)	(3 632)	(3 362)	(2 452)	(1 912)	(1 452)	(1 188)	(964)	(972)	(1 036)
Net Increase (Decrease) in Cash	91	43	(100)	136	(111)	(303)	100	112	(11)	(21)
Cash at Beginning of Year	482	572	616	516	652	541	237	337	449	438
Cash at End of Year	572	616	516	652	541	237	337	449	438	417

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
IFRS Compliant Statements
Financial Information MFR #1 -Scenario 1
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 300	3 436	3 531	3 670	3 758	3 823	3 904	3 989	4 086	4 225
Cash Paid to Suppliers and Employees	(1 139)	(1 163)	(1 175)	(1 199)	(1 218)	(1 230)	(1 253)	(1 277)	(1 304)	(1 357)
Interest Paid	(1 167)	(1 155)	(1 154)	(1 148)	(1 130)	(1 111)	(1 028)	(1 011)	(990)	(968)
Interest Received	6	14	30	42	50	61	42	54	66	79
	1 000	1 132	1 232	1 365	1 460	1 543	1 665	1 756	1 859	1 979
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	550	190	(10)	(10)	(30)	(10)	(10)	(30)	(30)	(50)
Sinking Fund Withdrawals	98	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	(114)	144	(55)	(54)	(42)	(52)	(51)	(39)	(46)	(57)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1 108)
Sinking Fund Payment	(255)	(261)	(272)	(283)	(292)	(298)	(275)	(285)	(295)	(307)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1 043)	(1 075)	(1 087)	(1 121)	(1 108)	(1 162)	(1 153)	(1 189)	(1 265)	(1 445)
Net Increase (Decrease) in Cash	(157)	201	90	190	310	329	461	528	548	478
Cash at Beginning of Year	417	260	461	552	742	1 052	1 381	1 842	2 369	2 917
Cash at End of Year	260	461	552	742	1 052	1 381	1 842	2 369	2 917	3 395

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	166	174	175	176	177	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 894	2 905	2 888	2 890
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	581	538	623
Net Movement in Regulatory Deferral	66	72	115	469	77	71	51	40	38	38	40
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	211	212	360	533	451	510	620	576	663
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	94	212	209	354	524	442	499	616	574	660
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**94**	**212**	**209**	**354**	**524**	**442**	**499**	**616**	**574**	**660**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	211	212	360	533	451	510	620	576	663
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	26%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.09	2.24	2.25	2.38
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.40	2.37	2.23	2.32

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	909	850	802	742	675	618
Finance Income	(29)	(46)	(56)	(18)	(19)	(19)	(25)	(31)	(49)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	179	180	181	182	184	185	187	189	195
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 896	2 895	2 892	2 882	2 837	2 824	2 798	2 768	2 721
Net Income before Net Movement in Reg. Deferral	695	798	912	1 028	1 184	1 314	1 460	1 617	1 707
Net Movement in Regulatory Deferral	40	42	46	47	47	49	47	45	43
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	735	840	958	1 074	1 231	1 363	1 507	1 663	1 750
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	731	835	950	1 065	1 220	1 350	1 493	1 647	1 734
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**731**	**835**	**950**	**1 065**	**1 220**	**1 350**	**1 493**	**1 647**	**1 734**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	735	840	958	1 074	1 231	1 363	1 507	1 663	1 750
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	28%	31%	35%	39%	43%	48%	53%	59%	65%
EBITDA Interest Coverage	2.50	2.66	2.87	3.11	3.47	3.80	4.27	4.87	5.53
Capital Coverage	2.42	2.49	2.70	2.74	2.95	3.10	3.27	3.17	3.25

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 772	1 988	2 228	2 082	2 194
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 359	30 540	30 346	30 418
Regulatory Deferral Balance	462	534	649	1 117	1 194	1 265	1 316	1 356	1 394	1 432	1 472
	21 733	24 839	27 776	29 569	31 254	31 388	31 509	31 715	31 934	31 779	31 890
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 054	3 264	3 618	4 142	4 584	5 083	5 699	6 273	6 933
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 727	29 521	31 206	31 339	31 461	31 666	31 886	31 730	31 842
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 776	29 569	31 254	31 388	31 509	31 715	31 934	31 779	31 890
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 832	22 203	21 617	20 952
Total Equity	2 856	3 163	3 513	3 776	4 155	4 684	4 810	5 376	6 007	6 595	7 269
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	26%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 816	3 619	2 345	2 023	2 455	2 592	3 591	4 024	5 458
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 996	31 770	30 444	30 096	30 492	30 590	31 546	31 997	33 450
Regulatory Deferral Balance	1 512	1 554	1 600	1 647	1 694	1 743	1 790	1 836	1 878
	32 508	33 325	32 044	31 743	32 186	32 333	33 336	33 832	35 329
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 951	14 977	14 280	13 859	13 743
Current and Other Liabilities	2 920	5 271	7 325	5 089	5 140	3 903	4 099	3 359	3 227
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7 664	8 498	9 448	10 513	11 733	13 082	14 575	16 222	17 956
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	32 459	33 276	31 996	31 694	32 138	32 285	33 287	33 784	35 280
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 508	33 325	32 044	31 743	32 186	32 333	33 336	33 832	35 329
Net Debt	20 205	19 368	18 400	17 345	16 117	14 758	13 238	11 631	9 928
Total Equity	8 014	8 854	9 812	10 884	12 112	13 471	14 972	16 629	18 372
Equity Ratio	28%	31%	35%	39%	43%	48%	53%	59%	65%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(916)	(934)	(934)	(948)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	766	759	961	1 168	1 171	1 306	1 456	1 427	1 530
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(720)	(724)	(752)	(776)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 748)	(3 059)	(2 437)	(1 850)	(1 477)	(997)	(816)	(820)	(834)	(858)
Net Increase (Decrease) in Cash	(309)	(146)	74	(18)	19	(236)	146	(17)	294	(285)	69
Cash at Beginning of Year	943	634	488	562	544	564	328	474	457	752	467
Cash at End of Year	634	488	562	544	564	328	474	457	752	467	536

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(963)	(979)	(995)	(1 018)	(1 014)	(1 028)	(1 048)	(1 072)	(1 082)
Interest Paid	(1 019)	(1 014)	(997)	(908)	(837)	(801)	(742)	(696)	(632)
Interest Received	25	50	63	19	14	22	35	48	66
	1 622	1 737	1 860	1 988	2 170	2 317	2 487	2 651	2 765
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 350	940	360	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(195)	(194)	(188)	(189)	(184)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 023)	(1 420)	(704)	(1 383)	(209)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(787)	(818)	(813)	(852)	(860)	(877)	(890)	(968)	(986)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(867)	(893)	(884)	(925)	(933)	(948)	(960)	(1 036)	(1 053)
Net Increase (Decrease) in Cash	503	591	(1 233)	(45)	214	(51)	823	232	1 503
Cash at Beginning of Year	536	1 039	1 630	397	352	566	515	1 338	1 570
Cash at End of Year	1 039	1 630	397	352	566	515	1 338	1 570	3 073

c) In MH16 Update with Interim, 2016/17 reflects actual results and cannot be restated to fully expense the restructuring charge. These costs could not have been recorded in 2016/17 as the details regarding the Voluntary Departure Program were not known until 2017/18 and therefore could not be estimated in 2016/17.

d) If the PUB did not permit the recovery of the difference in depreciation expense between the Equal Life Group (ELG) and CGAAP Average Service Life (ASL) methodologies, Manitoba Hydro understands that it would not be permitted to maintain a regulatory deferral account per the requirements of IFRS 14. If Manitoba Hydro cannot recover the difference in depreciation methodologies in future rates, then a deferred asset would not exist. For financial reporting purposes, Manitoba Hydro would be required to write-off the regulatory deferral account balance and reflect the ELG depreciation methodology. For rate-setting purposes, Manitoba Hydro would have to produce financial statements reflecting the ASL depreciation methodology which would require maintaining two sets of detailed asset accounting records. This requirement would be onerous, time consuming and costly given the thousands of transactions that are recorded each year pertaining to Manitoba Hydro's $20 billion of assets. In addition, maintaining two sets of financial statements creates potential confusion associated with different users looking at multiple sets of financial information for making decisions, evaluating financial performance and assessing rate change requirements.

In order to respond to this question, Manitoba Hydro is providing below financial statements reflecting MH16 Update with Interim and indefinite additions to the *Change in Depreciation Method* regulatory deferral account with no applied amortization (page 22 to 27 of this response). Additions to the regulatory deferral account are based on the difference between ELG and CGAAP ASL methodologies. The CGAAP ASL rates are based on the 2014 depreciation study.

The table below compares the accounting treatment in MH16 Update with Interim with the assumptions in part d) of this response.

	MH16 UPDATE WITH INTERIM	**PUB/MH I-1 PART (D)**
INELIGIBLE OVERHEAD		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	20 years
Ineligible Overhead Deferred Until	2022/23	2022/23
EQUAL LIFE GROUP (ELG)/AVERAGE SERVICE LIFE (ASL)		
ELG/ASL Amortization Period	20 years	None
ELG/ASL Deferred Until	2022/23	Indefinite

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1d
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	166	174	175	176	177	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 894	2 905	2 888	2 890
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	462	400	470	581	538	623
Net Movement in Regulatory Deferral	66	72	114	471	80	75	56	27	28	30	34
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	214	363	538	457	497	609	568	658
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	212	358	529	447	486	606	566	654
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**212**	**358**	**529**	**447**	**486**	**606**	**566**	**654**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	214	363	538	457	497	609	568	658
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	26%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.23	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.33	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1d
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	909	850	802	742	675	618
Finance Income	(29)	(46)	(56)	(18)	(19)	(19)	(25)	(31)	(49)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	179	180	181	182	184	185	187	189	196
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 896	2 895	2 892	2 882	2 837	2 824	2 798	2 768	2 721
Net Income before Net Movement in Reg. Deferral	695	798	912	1 028	1 184	1 314	1 460	1 617	1 707
Net Movement in Regulatory Deferral	37	41	48	51	54	59	59	61	60
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	732	839	960	1 079	1 238	1 372	1 519	1 678	1 768
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	728	834	952	1 069	1 227	1 360	1 505	1 662	1 752
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**728**	**834**	**952**	**1 069**	**1 227**	**1 360**	**1 505**	**1 662**	**1 752**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	732	839	960	1 079	1 238	1 372	1 519	1 678	1 768
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	28%	31%	35%	39%	43%	48%	53%	59%	65%
EBITDA Interest Coverage	2.48	2.64	2.85	3.08	3.44	3.78	4.24	4.84	5.50
Capital Coverage	2.39	2.46	2.67	2.71	2.93	3.07	3.25	3.15	3.22

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1d
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 772	1 988	2 228	2 082	2 194
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 193	30 359	30 540	30 346	30 418
Regulatory Deferral Balance	462	533	647	1 118	1 198	1 273	1 330	1 357	1 385	1 415	1 449
	21 733	24 839	27 774	29 570	31 258	31 396	31 523	31 716	31 925	31 761	31 867
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 264	3 622	4 151	4 598	5 084	5 690	6 255	6 909
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 521	31 210	31 348	31 475	31 667	31 876	31 712	31 818
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 570	31 258	31 396	31 523	31 716	31 925	31 761	31 867
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 833	22 203	21 617	20 952
Total Equity	2 856	3 163	3 511	3 776	4 159	4 693	4 824	5 377	5 998	6 577	7 246
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	26%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1d
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 817	3 620	2 345	2 024	2 456	2 593	3 592	4 025	5 458
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 996	31 771	30 445	30 097	30 493	30 591	31 547	31 997	33 451
Regulatory Deferral Balance	1 486	1 527	1 575	1 626	1 680	1 739	1 798	1 859	1 920
	32 482	33 298	32 020	31 723	32 173	32 330	33 345	33 856	35 370
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 951	14 977	14 280	13 859	13 743
Current and Other Liabilities	2 920	5 271	7 325	5 089	5 140	3 903	4 099	3 359	3 227
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7 638	8 472	9 423	10 493	11 720	13 079	14 584	16 246	17 998
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	32 433	33 249	31 971	31 674	32 125	32 281	33 296	33 808	35 322
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 482	33 298	32 020	31 723	32 173	32 330	33 345	33 856	35 370
Net Debt	20 204	19 367	18 400	17 344	16 116	14 757	13 237	11 630	9 927
Total Equity	7 988	8 828	9 787	10 864	12 099	13 468	14 981	16 653	18 414
Equity Ratio	28%	31%	35%	39%	43%	48%	53%	59%	65%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1d
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(936)	(954)	(954)	(968)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 168	1 171	1 286	1 436	1 407	1 510
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(17)	294	(285)	69
Cash at Beginning of Year	943	634	488	562	544	564	328	474	457	752	467
Cash at End of Year	634	488	562	544	564	328	474	457	752	467	536

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1d
(In Millions of Dollars)

For the year ended March 31

	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(982)	(999)	(1 015)	(1 038)	(1 034)	(1 047)	(1 068)	(1 092)	(1 102)
Interest Paid	(1 019)	(1 014)	(997)	(908)	(837)	(801)	(742)	(696)	(632)
Interest Received	26	50	63	19	14	22	35	48	66
	1 602	1 717	1 840	1 969	2 150	2 297	2 467	2 631	2 745
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 350	940	360	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(195)	(194)	(188)	(189)	(184)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 023)	(1 420)	(704)	(1 383)	(209)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	503	591	(1 233)	(45)	214	(51)	823	232	1 503
Cash at Beginning of Year	536	1 039	1 630	397	353	567	516	1 339	1 571
Cash at End of Year	1 039	1 630	397	353	567	516	1 339	1 571	3 074

e) The same concerns with respect to Scenario 1 of Attachment 28 discussed in part b) above, would apply to a scenario based on Attachment 46 of the 2016/17 Supplemental Filing. That is,

1. Substantial growth in regulatory deferral accounts results in intergenerational inequity and poses a risk to rate stability for future ratepayers in the event of the occurrence of adverse risks such as drought and/or higher interest rates.
2. Although changes in amortization periods can result in improvements to net income and retained earnings, such changes do not result in an improvement in the corporation's cash position, which is key to sustaining and improving the financial strength of Manitoba Hydro.

Notwithstanding, Manitoba Hydro is providing below financial statements reflecting MH16 Update with Interim and the assumptions in Scenario 1 of Attachment 46 of the 2016/17 Supplemental Filing, as outlined in the table below and including rate increases to attain a 75% debt equity ratio by 2033/34 (pages 29 to 34 of this response). The MH16 Update with Interim reflecting Attachment 46 provided below results in 3.99% rate increases from 2018/19 to 2033/34 to attain a 75% debt equity ratio by 2033/34.

	MH16 UPDATE WITH INTERIM	**PUB/MH I-1 PART (E)**
INELIGIBLE OVERHEAD		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferred Until	2022/23	Indefinite
EQUAL LIFE GROUP (ELG)/AVERAGE SERVICE LIFE (ASL)		
ELG/ASL Amortization Period	20 years	34 years (2.98%)
ELG/ASL Deferred Until	2022/23	Indefinite

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1e
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	117	183	249	322	396	473	558	648	743
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 184	2 265	2 465	2 673	2 830	2 864	2 950	2 916	3 033
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	829	905	1 156	1 202	1 203	1 199	1 212
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(15)	(13)	(13)	(16)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	176	176	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 404	2 531	2 865	2 959	2 996	3 009	3 052
Net Income before Net Movement in Reg. Deferral	(46)	13	34	(395)	61	142	(35)	(95)	(46)	(93)	(19)
Net Movement in Regulatory Deferral	66	72	115	469	77	71	51	40	38	38	40
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	149	74	138	212	16	(54)	(8)	(55)	21
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	94	150	72	133	204	6	(66)	(11)	(57)	18
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**94**	**150**	**72**	**133**	**204**	**6**	**(66)**	**(11)**	**(57)**	**18**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	149	74	138	212	16	(54)	(8)	(55)	21
* Additional Domestic Revenue											
Percent Increase		3.36%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%
Cumulative Percent Increase		3.36%	7.49%	11.77%	16.24%	20.87%	25.70%	30.72%	35.93%	41.36%	47.00%
Financial Ratios											
Equity	16%	15%	14%	14%	14%	14%	13%	13%	13%	13%	13%
EBITDA Interest Coverage	1.51	1.54	1.64	1.59	1.64	1.72	1.62	1.57	1.63	1.61	1.67
Capital Coverage	1.53	1.40	1.36	1.21	1.45	1.71	1.42	1.37	1.35	1.25	1.36

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1e
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	845	951	1 064	1 184	1 317	1 460	1 612	1 706	1 805
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 142	3 280	3 429	3 579	3 735	3 902	4 077	4 197	4 234
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 212	1 212	1 200	1 208	1 184	1 169	1 137	1 095	1 050
Finance Income	(14)	(21)	(21)	(16)	(17)	(18)	(20)	(24)	(27)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	179	180	181	182	184	185	187	188	195
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 085	3 111	3 132	3 182	3 173	3 192	3 197	3 194	3 174
Net Income before Net Movement in Reg. Deferral	57	169	297	396	563	710	880	1 004	1 059
Net Movement in Regulatory Deferral	40	42	46	47	47	49	47	45	43
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	97	211	343	443	610	759	927	1 049	1 102
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	93	206	335	433	599	746	913	1 034	1 086
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**93**	**206**	**335**	**433**	**599**	**746**	**913**	**1 034**	**1 086**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	97	211	343	443	610	759	927	1 049	1 102
* Additional Domestic Revenue									
Percent Increase	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	2.00%	2.00%
Cumulative Percent Increase	52.86%	58.97%	65.31%	71.91%	78.77%	85.90%	93.32%	97.19%	101.13%
Financial Ratios									
Equity	13%	14%	15%	17%	19%	22%	25%	29%	32%
EBITDA Interest Coverage	1.75	1.85	1.98	2.07	2.25	2.41	2.61	2.80	2.95
Capital Coverage	1.47	1.60	1.81	1.88	2.11	2.30	2.51	2.45	2.48

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1e
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 206	2 498	2 552	1 810	1 608	1 663	1 680	1 709	1 786
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 064	28 452	30 043	29 990	30 029	30 034	29 991	29 973	30 010
Regulatory Deferral Balance	462	534	649	1 117	1 194	1 265	1 316	1 356	1 394	1 432	1 472
	21 733	24 839	27 713	29 570	31 237	31 255	31 345	31 390	31 386	31 405	31 482
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 668	24 547	24 259	23 798	24 840
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 151	3 033	3 191	3 476	4 003	3 010
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 992	3 064	3 197	3 401	3 407	3 341	3 330	3 273	3 290
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(351)	(350)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 664	29 521	31 188	31 206	31 296	31 341	31 337	31 356	31 434
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 713	29 570	31 237	31 255	31 345	31 390	31 386	31 405	31 482
Net Debt	15 427	18 473	20 806	22 607	23 713	24 342	24 547	24 531	24 526	24 565	24 534
Total Equity	2 856	3 163	3 449	3 575	3 733	3 942	3 639	3 660	3 663	3 620	3 652
Equity Ratio	16%	15%	14%	14%	14%	14%	13%	13%	13%	13%	13%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1e
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	1 974	2 555	2 266	2 120	2 334	2 474	3 103	3 742	4 524
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 154	30 707	30 366	30 193	30 371	30 471	31 057	31 714	32 516
Regulatory Deferral Balance	1 512	1 554	1 600	1 647	1 694	1 743	1 790	1 836	1 878
	31 666	32 261	31 966	31 840	32 065	32 214	32 847	33 550	34 394
LIABILITIES AND EQUITY									
Long-Term Debt	24 972	22 995	20 302	21 762	21 326	21 963	21 280	21 659	21 543
Current and Other Liabilities	2 958	5 316	7 370	5 341	5 395	4 151	4 545	3 824	3 688
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	3 384	3 589	3 924	4 358	4 956	5 702	6 615	7 649	8 735
Accumulated Other Comprehensive Income	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	31 617	32 212	31 917	31 791	32 016	32 166	32 799	33 501	34 346
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 666	32 261	31 966	31 840	32 065	32 214	32 847	33 550	34 394
Net Debt	24 421	24 206	23 853	23 422	22 812	22 051	21 113	20 114	19 062
Total Equity	3 760	3 971	4 314	4 755	5 362	6 116	7 038	8 081	9 177
Equity Ratio	13%	14%	15%	17%	19%	22%	25%	29%	32%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1e
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 170	2 174	2 374	2 580	2 738	2 825	2 937	2 904	3 019
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(916)	(934)	(934)	(948)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(853)	(1 102)	(1 170)	(1 177)	(1 174)	(1 186)
Interest Received	17	5	11	22	26	19	7	7	6	6	9
	810	734	704	622	744	853	739	747	832	802	896
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 560	390	390	750	1 190
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	348	153	250
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(259)	(268)	(264)	(270)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 861	1 108	273	366	(111)	53	(81)	(12)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(720)	(724)	(752)	(776)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 748)	(3 059)	(2 437)	(1 850)	(1 477)	(997)	(816)	(820)	(834)	(858)
Net Increase (Decrease) in Cash	(309)	(146)	11	46	2	(351)	108	(181)	66	(113)	26
Cash at Beginning of Year	943	634	488	499	545	546	195	303	123	188	75
Cash at End of Year	634	488	499	545	546	195	303	123	188	75	101

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1e
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 129	3 266	3 415	3 565	3 721	3 887	4 062	4 183	4 219
Cash Paid to Suppliers and Employees	(962)	(978)	(995)	(1 018)	(1 014)	(1 027)	(1 048)	(1 071)	(1 082)
Interest Paid	(1 192)	(1 201)	(1 204)	(1 198)	(1 168)	(1 164)	(1 136)	(1 109)	(1 071)
Interest Received	12	29	29	16	13	24	27	41	47
	988	1 115	1 245	1 364	1 552	1 720	1 905	2 044	2 114
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	190	390	1 770	3 790	1 950	1 740	760	1 100	370
Sinking Fund Withdrawals	150	60	500	521	0	230	43	10	275
Sinking Fund Payment	(270)	(277)	(285)	(269)	(256)	(263)	(257)	(262)	(269)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 096)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(85)	108	(460)	(359)	(684)	(690)	(554)	(644)	(293)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(787)	(818)	(813)	(852)	(860)	(877)	(890)	(968)	(986)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(867)	(893)	(884)	(925)	(933)	(948)	(960)	(1 036)	(1 053)
Net Increase (Decrease) in Cash	35	331	(99)	80	(65)	82	391	364	767
Cash at Beginning of Year	101	136	467	369	449	384	466	857	1 222
Cash at End of Year	136	467	369	449	384	466	857	1 222	1 989

f) Manitoba Hydro has concerns with respect to a scenario based on Attachment 28, as discussed in part b) of this response.

Notwithstanding, Manitoba Hydro is providing below financial statements reflecting the MH16 Update with Interim and the assumptions in Attachment 28 Scenario 1 from the 2016/17 Supplemental Filing as outlined in the table below, as well as rate increases as applied in MH15 (3.95% 2019-2029, 2% thereafter) (pages 36 to 41 of this response).

	MH16 UPDATE WITH INTERIM	**PUB/MH I-1 PART (F)**
INELIGIBLE OVERHEAD		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferred Until	2022/23	Indefinite
EQUAL LIFE GROUP (ELG)/AVERAGE SERVICE LIFE (ASL)		
ELG/ASL Amortization Period	20 years	34 years (2.98%)
ELG/ASL Deferred Until	2022/23	Indefinite

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1f
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	116	181	247	319	392	469	552	641	735
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 184	2 263	2 463	2 670	2 826	2 859	2 944	2 909	3 024
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	829	905	1 156	1 202	1 204	1 201	1 214
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(14)	(12)	(14)	(16)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	176	176	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 404	2 531	2 865	2 959	2 997	3 011	3 054
Net Income before Net Movement in Reg. Deferral	(46)	13	33	(396)	59	139	(39)	(100)	(53)	(101)	(30)
Net Movement in Regulatory Deferral	66	72	115	469	77	71	51	40	38	38	40
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	148	73	136	209	12	(59)	(15)	(64)	10
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	94	149	70	131	201	2	(71)	(18)	(66)	7
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**94**	**149**	**70**	**131**	**201**	**2**	**(71)**	**(18)**	**(66)**	**7**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	148	73	136	209	12	(59)	(15)	(64)	10
* Additional Domestic Revenue											
Percent Increase		3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase		3.36%	7.44%	11.69%	16.10%	20.68%	25.45%	30.41%	35.56%	40.91%	46.48%
Financial Ratios											
Equity	16%	15%	14%	14%	14%	14%	13%	13%	13%	13%	13%
EBITDA Interest Coverage	1.51	1.54	1.64	1.59	1.64	1.72	1.62	1.57	1.62	1.60	1.66
Capital Coverage	1.53	1.40	1.36	1.20	1.45	1.70	1.41	1.36	1.34	1.24	1.34

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH I-1f
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	835	940	1 001	1 065	1 137	1 213	1 291	1 374	1 460
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 133	3 269	3 366	3 460	3 555	3 654	3 756	3 865	3 889
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 219	1 213	1 201	1 216	1 200	1 198	1 183	1 156	1 124
Finance Income	(16)	(20)	(19)	(15)	(16)	(17)	(20)	(21)	(20)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	179	180	181	182	184	185	187	188	195
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 090	3 114	3 135	3 191	3 189	3 222	3 243	3 257	3 255
Net Income before Net Movement in Reg. Deferral	43	155	231	269	365	432	513	608	634
Net Movement in Regulatory Deferral	40	42	46	47	47	49	47	45	43
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	83	197	277	315	412	481	560	653	676
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	79	192	269	306	401	469	546	638	660
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**79**	**192**	**269**	**306**	**401**	**469**	**546**	**638**	**660**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	83	197	277	315	412	481	560	653	676
* Additional Domestic Revenue									
Percent Increase	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	52.26%	58.28%	61.44%	64.67%	67.97%	71.33%	74.75%	78.25%	81.81%
Financial Ratios									
Equity	13%	14%	15%	16%	17%	19%	21%	23%	26%
EBITDA Interest Coverage	1.73	1.84	1.93	1.95	2.07	2.14	2.24	2.36	2.43
Capital Coverage	1.46	1.57	1.72	1.70	1.84	1.92	2.02	1.98	1.98

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1f
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 205	2 496	2 547	1 803	1 597	1 647	1 657	1 875	1 738
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 063	28 450	30 039	29 983	30 018	30 018	29 969	30 139	29 962
Regulatory Deferral Balance	462	534	649	1 117	1 194	1 265	1 316	1 356	1 394	1 432	1 472
	21 733	24 839	27 712	29 568	31 233	31 248	31 334	31 374	31 363	31 571	31 434
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 668	24 547	24 259	23 998	24 840
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 151	3 033	3 192	3 476	4 001	3 005
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 992	3 062	3 193	3 393	3 395	3 324	3 307	3 241	3 248
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(351)	(350)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 663	29 519	31 184	31 199	31 285	31 325	31 314	31 523	31 386
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 712	29 568	31 233	31 248	31 334	31 374	31 363	31 571	31 434
Net Debt	15 427	18 473	20 806	22 609	23 717	24 349	24 558	24 548	24 549	24 599	24 582
Total Equity	2 856	3 163	3 449	3 573	3 729	3 935	3 627	3 643	3 640	3 588	3 609
Equity Ratio	16%	15%	14%	14%	14%	14%	13%	13%	13%	13%	13%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH I-1f
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 115	2 479	2 124	2 052	2 468	2 528	2 990	3 437	4 195
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 295	30 630	30 224	30 125	30 505	30 526	30 945	31 409	32 188
Regulatory Deferral Balance	1 512	1 554	1 600	1 647	1 694	1 743	1 790	1 836	1 878
	31 807	32 184	31 824	31 772	32 199	32 269	32 735	33 245	34 066
LIABILITIES AND EQUITY									
Long-Term Debt	25 172	22 995	20 302	21 962	21 926	22 763	22 280	22 859	23 143
Current and Other Liabilities	2 956	5 310	7 365	5 338	5 392	4 146	4 539	3 822	3 688
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	3 327	3 518	3 787	4 093	4 494	4 963	5 509	6 146	6 807
Accumulated Other Comprehensive Income	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	31 758	32 136	31 775	31 723	32 150	32 220	32 686	33 196	34 017
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 807	32 184	31 824	31 772	32 199	32 269	32 735	33 245	34 066
Net Debt	24 480	24 283	23 995	23 691	23 278	22 796	22 226	21 618	20 991
Total Equity	3 703	3 900	4 177	4 490	4 899	5 377	5 931	6 578	7 248
Equity Ratio	13%	14%	15%	16%	17%	19%	21%	23%	26%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1f
(In Millions of Dollars)

For the year ended March 31	ACTUAL										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 170	2 173	2 371	2 577	2 734	2 821	2 931	2 897	3 011
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(916)	(934)	(934)	(948)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(853)	(1 102)	(1 170)	(1 178)	(1 178)	(1 191)
Interest Received	17	5	11	22	26	19	7	6	6	6	9
	810	734	703	621	741	850	735	741	826	791	881
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 560	390	390	950	990
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	348	153	250
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(259)	(268)	(264)	(271)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 861	1 108	273	366	(111)	53	119	(213)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(720)	(724)	(752)	(776)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 748)	(3 059)	(2 437)	(1 850)	(1 477)	(997)	(816)	(820)	(834)	(858)
Net Increase (Decrease) in Cash	(309)	(146)	10	44	(0)	(355)	104	(186)	59	76	(190)
Cash at Beginning of Year	943	634	488	498	543	542	188	292	106	165	241
Cash at End of Year	634	488	498	543	542	188	292	106	165	241	52

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH I-1f
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 120	3 255	3 352	3 446	3 540	3 640	3 741	3 851	3 874
Cash Paid to Suppliers and Employees	(962)	(978)	(995)	(1 018)	(1 014)	(1 027)	(1 048)	(1 071)	(1 081)
Interest Paid	(1 196)	(1 206)	(1 204)	(1 205)	(1 185)	(1 195)	(1 182)	(1 167)	(1 144)
Interest Received	15	27	27	15	12	23	27	39	41
	977	1 098	1 180	1 238	1 354	1 440	1 538	1 651	1 690
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	190	1 770	3 990	2 350	1 940	960	1 300	770
Sinking Fund Withdrawals	150	60	503	522	0	230	43	10	275
Sinking Fund Payment	(270)	(277)	(285)	(270)	(258)	(268)	(265)	(273)	(282)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 096)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	115	(92)	(457)	(159)	(286)	(495)	(362)	(454)	94
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(787)	(818)	(813)	(852)	(860)	(877)	(890)	(968)	(986)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(867)	(893)	(884)	(925)	(933)	(948)	(960)	(1 036)	(1 053)
Net Increase (Decrease) in Cash	224	113	(162)	154	135	(3)	217	161	730
Cash at Beginning of Year	52	275	389	227	380	515	513	729	891
Cash at End of Year	275	389	227	380	515	513	729	891	1 621

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REFERENCE:

PUB/MH I-1 (a)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please refile the schedule of regulatory deferral account balances for the twenty year IFF 16 Update with Interim, assuming continued recognition of the difference between ASL and ELG amortized over the expected remaining lives of the related assets.

b) Please refile the schedule of regulatory deferral account balances for the twenty year IFF 16 Update with Interim, assuming no recognition of a regulatory asset or liability for the difference between ASL and ELG.

RATIONALE FOR QUESTION:

RESPONSE:

a) As discussed in PUB/MH I-1b, Manitoba Hydro has the following concerns with respect to this scenario:

   1. Substantial growth in regulatory deferral accounts results in the burden of recovery of today's IFRS impacts being pushed out to future ratepayers and poses a risk to rate stability for future ratepayers in the event of the occurrence of adverse risks such as drought and/or higher interest rates.
   2. Although changes in amortization periods can result in improvements to net income and retained earnings, such changes do not result in any change or improvement in the corporation's cash flow position or debt load, which is key to sustaining and improving the financial strength of Manitoba Hydro.

   Notwithstanding the concerns outlined above, Manitoba Hydro is providing the following table with the twenty-year schedule of regulatory deferral account balances for MH16 Update with Interim reflecting ELG/ASL deferred indefinitely and a 34-year amortization period as outlined in Manitoba Hydro's response to PUB/MH I-1b.

	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Opening balance of net regulatory deferral											
Power Smart programs	$ 188 873	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361
Change in depreciation method	59 441	90 827	124 778	164 284	203 317	242 450	283 500	331 524	380 148	428 052	475 253
Deferred ineligible overhead	40 400	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938
Loss on disposal of assets	8 339	9 641	9 352	8 775	8 198	7 622	7 045	6 468	5 891	5 314	4 737
Site restoration costs	30 710	28 001	26 689	25 401	22 954	20 712	18 855	16 232	13 998	11 828	9 837
Regulatory costs	3 821	5 409	6 131	4 805	3 260	2 648	2 155	2 709	2 496	2 841	2 620
Acquisition costs	10 480	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560
Affordable Energy Fund	4 324	4 163	3 714	3 234	2 670	2 126	1 615	1 126	672	350	203
Conawapa Generation	-	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294
DSM deferral debit balance	43 600	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(43 600)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	346 387	412 817	484 625	598 165	1 065 233	1 140 072	1 208 383	1 256 619	1 274 150	1 290 364	1 306 802
Additions to regulatory deferral accounts											
Power Smart programs	$ (50 453)	$ (57 184)	$ (99 404)	$ (94 251)	$ (88 857)	$ (86 929)	$ (66 549)	$ (60 271)	$ (62 350)	$ (66 576)	$ (70 722)
Change in depreciation method	(31 386)	(33 952)	(39 506)	(42 869)	(44 702)	(47 924)	(56 279)	(58 430)	(59 420)	(60 473)	(61 489)
Deferred ineligible overhead	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	(20 200)	-	-	-	-
Loss on disposal of assets	(1 302)	-	-	-	-	-	-	-	-	-	-
Site restoration costs	(1 361)	(2 794)	(2 703)	(1 408)	(1 317)	(1 133)	(6)	-	-	-	-
Regulatory costs	(3 946)	(3 664)	(2 339)	(1 339)	(1 882)	(1 391)	(1 954)	(1 444)	(2 029)	(1 499)	(2 114)
Acquisition costs	-	-	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	(63)	-	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	(379 758)	-	-	-	-	-	-	-
DSM deferral debit balance	(5 200)	-	-	-	-	-	-	-	-	-	-
DSM deferral credit balance	5 200	-	-	-	-	-	-	-	-	-	-
	(108 712)	(117 794)	(164 151)	(539 825)	(156 958)	(157 576)	(144 988)	(120 146)	(123 799)	(128 549)	(134 324)
Amortization of regulatory deferral accounts											
Power Smart programs	$ 34 937	$ 35 742	$ 36 662	$ 43 202	$ 49 473	$ 55 519	$ 61 480	$ 65 459	$ 68 888	$ 71 976	$ 73 251
Change in depreciation method	-	-	-	3 836	5 569	6 874	8 254	9 807	11 516	13 272	15 059
Deferred ineligible overhead	-	1 768	4 545	5 555	6 565	7 575	8 585	9 090	9 090	9 090	9 090
Loss on disposal of assets	-	288	577	577	577	577	577	577	577	577	577
Site restoration costs	4 070	4 106	3 990	3 855	3 559	2 990	2 629	2 234	2 170	1 991	1 826
Regulatory costs	2 358	2 942	3 665	2 884	2 495	1 883	1 400	1 657	1 684	1 721	1 749
Acquisition costs	692	692	692	692	692	692	692	692	692	692	692
Affordable Energy Fund	224	449	480	563	545	511	489	454	322	147	97
Conawapa Generation	-	-	-	11 592	12 645	12 645	12 645	12 645	12 645	12 645	12 645
DSM deferral debit balance	-	-	-	-	-	-	-	-	-	-	-
DSM deferral credit balance	-	-	-	-	-	-	-	-	-	-	-
	42 281	45 987	50 612	72 756	82 119	89 266	96 752	102 616	107 585	112 111	114 987

	2016/17 Actual	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2020/21 Forecast	2021/22 Forecast	2022/23 Forecast	2023/24 Forecast	2024/25 Forecast	2025/26 Forecast	2026/27 Forecast
Closing balance of net regulatory deferral											
Power Smart programs	$ 204 389	$ 225 832	$ 288 574	$ 339 622	$ 379 007	$ 410 417	$ 415 486	$ 410 298	$ 403 760	$ 398 361	$ 395 831
Change in depreciation method	90 827	124 778	164 284	203 317	242 450	283 500	331 524	380 148	428 052	475 253	521 683
Deferred ineligible overhead	60 600	79 033	94 688	109 333	122 968	135 593	147 208	138 118	129 028	119 938	110 848
Loss on disposal of assets	9 641	9 352	8 775	8 198	7 622	7 045	6 468	5 891	5 314	4 737	4 160
Site restoration costs	28 001	26 689	25 401	22 954	20 712	18 855	16 232	13 998	11 828	9 837	8 011
Regulatory costs	5 409	6 131	4 805	3 260	2 648	2 155	2 709	2 496	2 841	2 620	2 985
Acquisition costs	9 788	9 096	8 404	7 712	7 020	6 328	5 636	4 944	4 252	3 560	2 868
Affordable Energy Fund	4 163	3 714	3 234	2 670	2 126	1 615	1 126	672	350	203	106
Conawapa Generation	-	-	-	368 166	355 521	342 875	330 230	317 585	304 939	292 294	279 649
DSM deferral debit balance	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	412 817	**484 625**	**598 165**	**1 065 233**	**1 140 072**	**1 208 383**	**1 256 619**	**1 274 150**	**1 290 364**	**1 306 802**	**1 326 139**
Total net movement in regulatory deferral balances	**(66 431)**	**(71 808)**	**(113 540)**	**(467 068)**	**(74 839)**	**(68 311)**	**(48 236)**	**(17 530)**	**(16 214)**	**(16 438)**	**(19 337)**
Year over year $ change	$ 7 910	$ (5 377)	$ (41 731)	$ (353 529)	$ 392 229	$ 6 529	$ 20 074	$ 30 706	$ 1 316	$ (224)	$ (2 899)
Year over year % change	-11%	8%	58%	311%	-84%	-9%	-29%	-64%	-8%	1%	18%

	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Opening balance of net regulatory deferral									
Power Smart programs	$ 395 831	$ 395 200	$ 397 041	$ 404 833	$ 413 227	$ 423 916	$ 436 640	$ 449 200	$ 460 818
Change in depreciation method	521 683	567 348	612 174	656 296	699 660	742 452	784 611	826 058	866 692
Deferred ineligible overhead	110 848	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128
Loss on disposal of assets	4 160	3 583	3 006	2 429	1 852	1 275	698	121	(456)
Site restoration costs	8 011	6 286	4 773	3 439	2 393	1 502	885	452	157
Regulatory costs	2 985	2 760	3 145	2 911	3 313	3 070	3 489	3 235	3 672
Acquisition costs	2 868	2 176	1 484	806	506	206	7	1	1
Affordable Energy Fund	106	11	11	11	11	11	11	11	11
Conawapa Generation	279 649	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486
DSM deferral debit balance	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	1 326 139	1 346 125	1 368 659	1 396 015	1 424 517	1 454 251	1 486 426	1 517 426	1 547 508
Additions to regulatory deferral accounts									
Power Smart programs	$ (74 678)	$ (78 900)	$ (82 801)	$ (82 257)	$ (83 893)	$ (85 623)	$ (87 367)	$ (89 135)	$ (90 933)
Change in depreciation method	(62 541)	(63 550)	(64 724)	(65 878)	(67 252)	(68 602)	(69 915)	(71 165)	(72 519)
Deferred ineligible overhead	-	-	-	-	-	-	-	-	-
Loss on disposal of assets	-	-	-	-	-	-	-	-	-
Site restoration costs	-	-	-	-	-	-	-	-	-
Regulatory costs	(1 564)	(2 206)	(1 632)	(2 302)	(1 703)	(2 402)	(1 777)	(2 506)	(1 854)
Acquisition costs	-	-	-	-	-	-	-	-	-
Affordable Energy Fund	-	-	-	-	-	-	-	-	-
Conawapa Generation	-	-	-	-	-	-	-	-	-
DSM deferral debit balance	-	-	-	-	-	-	-	-	-
DSM deferral credit balance	-	-	-	-	-	-	-	-	-
	(138 784)	(144 655)	(149 157)	(150 436)	(152 849)	(156 627)	(159 059)	(162 806)	(165 306)
Amortization of regulatory deferral accounts									
Power Smart programs	$ 75 309	$ 77 059	$ 75 008	$ 73 863	$ 73 203	$ 72 900	$ 74 807	$ 77 517	$ 80 195
Change in depreciation method	16 876	18 724	20 603	22 514	24 460	26 444	28 468	30 532	32 634
Deferred ineligible overhead	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090	9 090
Loss on disposal of assets	577	577	577	577	577	577	577	577	577
Site restoration costs	1 724	1 514	1 334	1 046	891	616	433	295	188
Regulatory costs	1 789	1 821	1 866	1 900	1 947	1 982	2 031	2 068	2 120
Acquisition costs	692	692	678	300	300	199	6	-	-
Affordable Energy Fund	95	-	-	-	-	-	-	-	-
Conawapa Generation	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645	12 645
DSM deferral debit balance	-	-	-	-	-	-	-	-	-
DSM deferral credit balance	-	-	-	-	-	-	-	-	-
	118 797	122 121	121 801	121 935	123 114	124 453	128 058	132 723	137 449

	2027/28 Forecast	2028/29 Forecast	2029/30 Forecast	2030/31 Forecast	2031/32 Forecast	2032/33 Forecast	2033/34 Forecast	2034/35 Forecast	2035/36 Forecast
Closing balance of net regulatory deferral									
Power Smart programs	$ 395 200	$ 397 041	$ 404 833	$ 413 227	$ 423 916	$ 436 640	$ 449 200	$ 460 818	$ 471 556
Change in depreciation method	567 348	612 174	656 296	699 660	742 452	784 611	826 058	866 692	906 577
Deferred ineligible overhead	101 758	92 668	83 578	74 488	65 398	56 308	47 218	38 128	29 038
Loss on disposal of assets	3 583	3 006	2 429	1 852	1 275	698	121	(456)	(1 032)
Site restoration costs	6 286	4 773	3 439	2 393	1 502	885	452	157	(31)
Regulatory costs	2 760	3 145	2 911	3 313	3 070	3 489	3 235	3 672	3 407
Acquisition costs	2 176	1 484	806	506	206	7	1	1	1
Affordable Energy Fund	11	11	11	11	11	11	11	11	11
Conawapa Generation	267 003	254 358	241 713	229 067	216 422	203 776	191 131	178 486	165 840
DSM deferral debit balance	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)	(48 800)
	1 346 125	**1 368 659**	**1 396 015**	**1 424 517**	**1 454 251**	**1 486 426**	**1 517 426**	**1 547 508**	**1 575 366**
Total net movement in regulatory deferral balances	**(19 986)**	**(22 534)**	**(27 356)**	**(28 501)**	**(29 735)**	**(32 174)**	**(31 001)**	**(30 082)**	**(27 857)**
Year over year $ change	$ (649)	$ (2 548)	$ (4 822)	$ (1 145)	$ (1 234)	$ (2 439)	$ 1 174	$ 918	$ 2 225
Year over year % change	3%	13%	21%	4%	4%	8%	-4%	-3%	-7%

b) As per IFRS 14 *Regulatory Deferral Accounts*, differences in the timing of when expenditures must be recognized for financial reporting and rate setting purposes must be recognized in a regulatory deferral account. As such, a scenario that does not recognize a regulatory deferral account has not been prepared.

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REFERENCE:

Tab 6 Page 3 of 55

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether and when Manitoba Hydro will seek approval for disposition of the Bipole III reserve funds.

RATIONALE FOR QUESTION:

RESPONSE:

Manitoba Hydro's financial forecast (MH16 Update) assumes recognition of the deferred revenue related to the Bipole III deferral account over five years to begin upon in-service of Bipole III. Manitoba Hydro has not sought formal approval of the disposition of the BiPole III reserve funds because such disposition is not a "rate for service" requiring PUB approval. Nevertheless, it is recognized that Manitoba Hydro accrued revenues from rate increases to the Bipole III Deferral Account in accordance with the PUB's direction in Orders 43/13, 49/14, 73/15 and 59/16. In accordance with Order 70/17, Appendix A, the Bipole III Deferral Account has been included as an Issue to be addressed as part of the current GRA proceeding. As such, Manitoba Hydro expects the PUB will issue findings and direction with respect to the proposed disposition of the Bipole III Deferral Account in its Final Order flowing from this GRA.

REFERENCE:

Tab 6 Page 3 of 55

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a continuity schedule of annual contributions and proposed drawdowns of the Bipole III reserve account since inception.

RATIONALE FOR QUESTION:

RESPONSE:

The continuity schedule below (based on the MH16 Update with Interim) displays the annual contributions and proposed drawdowns of the Bipole III reserve account by fiscal year.

Bipole III Reserve Account Reconciliation
(In thousands of dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening balance	-	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605
Contributions	18 825	30 249	51 204	96 018	151 017	51 739	-	-	-	-	-
Drawdowns	-	-	-	-	-	(53 207)	(79 810)	(79 810)	(79 810)	(79 810)	(26 605)
Ending balance	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605	-

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REFERENCE:

Tab 10, Pages 7-10

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has expressed the concern that the methodology suggested by the Board as being consistent with Order 73/15 (i.e., amortize the regulatory accounts through OIC) is not permissible under IFRS.

QUESTION:

a) Please confirm that the continued use of ASL deprecation would eventually result in the amortization of the full value of Manitoba Hydro's assets. If not, please explain why.

b) If part (a) is confirmed, when is it necessary to amortize the ELG/ASL differences recorded in the account? In theory won't the account "self-clear" over time?

RATIONALE FOR QUESTION:

To explore alternative treatments of the ELG/ASL Regulatory Deferral Account.

RESPONSE:

a) Manitoba Hydro confirms that the continued use of the CGAAP ASL depreciation method for regulatory purposes would eventually result in the amortization of the full value of Manitoba Hydro's assets.

b) Under IFRS (section IFRS 14 *Regulatory Deferral Accounts*), Manitoba Hydro is required to establish a regulatory deferral account to record the difference in depreciation between the method used for financial reporting purposes (Equal Life Group or ELG) and the method used for rate setting purposes (CGAAP Average Service Life or ASL). For the periods 2014/15 through to 2022/23, Manitoba Hydro is proposing to defer the annual difference in depreciation expense between the ELG and CGAAP ASL method and amortize these deferrals over 20 year periods commencing in 2019/20. Consistent with

Manitoba Hydro's response to MIPUG MFR 5 of this application, the 20 year amortization is intended to limit the extent of growth in the regulatory deferral account. Manitoba Hydro is of the view that significant regulatory deferral account balances, such as the $1.8 billion balance in the year 2036 in Scenario 1 of MIPUG MFR 5, may result in intergenerational inequity in that the burden of recovery of today's IFRS impacts is being pushed out to future ratepayers. In addition, extended or indefinite deferral periods can create concerns by auditors regarding the ability of the utility to recover such deferrals from its ratepayers.

Although in theory the difference between ELG and CGAAP ASL depreciation expense should eventually clear-out over the lifetime of the respective plant assets, Manitoba Hydro plans to more than double its plant asset base in the next ten years resulting in significant growth in the annual difference between ELG and CGAAP ASL depreciation. Notably, the majority of the growth in plant assets is comprised of very long-lived assets (i.e. Bipole III and the Keeyask Generating Station). As such, the annual ELG and CGAAP ASL depreciation difference will not start to reverse or recover until beyond the 20 year forecast. It is not unreasonable to anticipate that over the next 20 years, circumstances may arise such as drought or rising interest rates that would add pressure to existing customer rates. Such pressure would only be compounded by the need to also recover excessively large regulatory deferral balances. This concern is consistent with past concerns of the PUB with respect to aggressive capitalization and deferral policies as noted on pages 92 and 93 of PUB Order 116/08 which states,

> *"And, in this Order, the Board continues to be concerned with MH's "aggressive "capitalization and deferral policies with respect to OM&A expenses. While there is an argument for the practice, the net result is that costs now being incurred are not reflected in rates until years, in fact decades, later, meaning the current generation of ratepayers leaves the results for the generations that will follow to meet. The following concern, from Order 143/04, echoes past concerns raised by the Board with respect to the capitalization policies followed by MH. The Board then stated: ",… While the Board understands that many of the projects undertaken by MH are long-term in nature, both from a benefit and cost perspective, aggressively capitalizing costs and selecting long amortization periods increases the rate risks to future generations of electric customers"*

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k) Please provide the basis for assuming that $50 million of downsizing costs would be expensed in 2017/18 rather than deferred and amortized (as a financial statement presentation, or if needed as a regulatory deferral) to match this expense with the long-term benefits expected to be achieved by the downsizing.

RATIONALE FOR QUESTION:

RESPONSE:

e) The losses on disposal of assets as presented in Figure 6.30 of Tab 6 represent the net loss as calculated in accordance with the Equal Life Group (ELG) method of depreciation. Under ELG, assets are considered to be fully depreciated on retirement, provided the timing of retirements is consistent with that expected under the depreciation assumptions used. Losses or gains are experienced when assets are retired earlier or later than expected. The net loss (or gain) for financial reporting purposes is determined by comparing actual retirements to expected retirements, for each vintage year within each depreciable component, with a gain or loss calculated as the net book value on the difference in actual versus expected retirements, adjusted for the cost of removing assets from service as well as any proceeds received on disposition.

Under ELG, it is expected that gains and losses will be minimal. Experienced losses ranging from 1.6% - 0.8% of depreciation expense since 2014/15 support that expectation. Given the expectation that net losses will continue to remain relatively small, no provision was made in the forecast for future gains or losses on disposal of assets.

For financial reporting purposes under IFRS, Manitoba Hydro is required to recognize gains and losses associated with the disposal of assets as an immediate charge against income. Prior to the implementation of IFRS, Manitoba Hydro deferred the recognition of gains and losses on the disposal of assets by recognizing the gains or losses within accumulated depreciation. The balances were included as an adjustment to future depreciation rates (as determined in formal depreciation studies) and as such, gains and losses were recognized over the remaining service life of the assets. For rate-setting purposes, Manitoba Hydro is continuing to defer gains and losses on the disposition of assets, consistent with the direction provided by the Public Utilities Board in Order 73/15.

Gains and losses on the disposal of assets are initially recorded in Depreciation and Amortization expense and are offset within the Net Movement in Regulatory Deferral Account. Effectively, this accounting treatment defers the gains and losses in a regulatory deferral account which is then subsequently amortized over a 20 year period.

f) Under IFRS, it is a requirement to record gains or losses on disposal of assets within net income. Manitoba Hydro did not previously state that the ELG method of depreciation would eliminate the need to record losses on disposal. Representations made by Manitoba Hydro during the 2014/15 & 2015/16 Electric GRA stated that the magnitude of gains and losses to be reported under IFRS would be minimized by using ELG as compared to Manitoba Hydro's CGAAP Average Service Life (ASL) methodology. The following testimony from the 2014/15 & 2015/16 GRA confirms these representations:
Transcript Page 3456, Lines 11-17 (Ms. Sandy Bauerlein) :

The second difference that IFRS requires is that gains and losses on retirement of assets have to be charged immediately into income un – under IFRS. Under Canadian GAAP any gains and losses on retirement of the asset are charged against accumulated depreciation and are factored into future depreciation rates.

Transcript Page 3472, Line 19 to Page 3473, Line 2 (Ms. Sandy Bauerlein):
So again, under IFRS, though, the expectation is because you have a greater degree of precision, because the depreciation rates themselves are calculated more representative of the service lives in the group, it will result in fewer gains and losses. So we expect to have – reductions in gains and losses are expected under the ELG method because that calculation considers that service life dispersion.

Financial results for the three years since the implementation of IFRS further support this representation. The following table compares the net losses reported under the ELG methodology implemented under IFRS versus the net losses which would have been experienced under Manitoba Hydro's previous CGAAP ASL methodology.

$ millions	2014/15 Actual	2015/16 Actual	2016/17 Outlook
Net loss reported (IFRS ELG)	5 527	2 812	3 200
Net loss under CGAAP ASL	21 501	14 386	23 200

g) Please see below for a version of MIPUG/MH I-18 (Case 1) from the 2014/15 & 2015/16 Electric GRA updated for the proposed accounting treatment for the annual IFRS-compliant ELG – CGAAP ASL difference as assumed in MH16 Update with Interim. A summary of the assumptions used in the accounting for the IFRS-compliant ELG – CGAAP ASL difference is as follows:

- The difference in depreciation expense between the ELG and ASL methods is deferred in a regulatory deferral account starting in 2014/15.
- The annual difference in depreciation is amortized over a 20 year period.
- Amortization of the deferral balance commences in 2019/20.
- No deferral of the difference in ELG-ASL depreciation following the final in-service date for the Keeyask Generating Station (i.e. no deferrals after 2022/23).

Please note that the years presented in the table start in fiscal 2014 as no ELG-ASL deferral account was maintained in the years prior to Manitoba Hydro's transition to IFRS.

MIPUG/MH I-6(g)
Case 1 2015 GRA, ELG - ASL comparison
Assumes 20 yr amortization of ELG-ASL difference (starting in 2019/20) and no deferrals following 2022/23 fiscal year

Year	Cost	ELG Annual Rate	ELG Annual Expense	ASL Annual Rate	ASL Annual Expense	Annual ELG - ASL Deferral	Cumulative ELG - ASL Deferral	Annual (20 yr) Amortization ELG-ASL Deferral	Cumulative Amortization ELG-ASL Deferral	Unamortized Balance ELG-ASL Deferral
2014	890.40	0.80%	7.12	0.823%	7.33	-	-	-	-	-
2015	884.84	0.80%	7.08	0.823%	7.28	(0.20)	(0.20)	-	-	(0.20)
2016	879.02	0.79%	6.94	0.823%	7.23	(0.29)	(0.49)	-	-	(0.49)
2017	873.00	0.79%	6.90	0.823%	7.18	(0.29)	(0.78)	-	-	(0.78)
2018	866.77	0.79%	6.85	0.823%	7.13	(0.29)	(1.07)	-	-	(1.07)
2019	860.34	0.79%	6.80	0.823%	7.08	(0.28)	(1.35)	-	-	(1.35)
2020	853.70	0.79%	6.74	0.823%	7.03	(0.28)	(1.63)	(0.07)	(0.07)	(1.57)
2021	846.78	0.78%	6.60	0.823%	6.97	(0.36)	(2.00)	(0.08)	(0.15)	(1.85)
2022	839.65	0.78%	6.55	0.823%	6.91	(0.36)	(2.36)	(0.10)	(0.25)	(2.11)
2023	832.30	0.78%	6.49	0.823%	6.85	(0.36)	(2.72)	(0.12)	(0.37)	(2.35)
2024	824.73	0.78%	6.43	0.823%	6.79	-	(2.72)	(0.14)	(0.50)	(2.21)
2025	816.95	0.78%	6.37	0.823%	6.72	-	(2.72)	(0.14)	(0.64)	(2.08)
2026	808.88	0.77%	6.23	0.823%	6.66	-	(2.72)	(0.14)	(0.77)	(1.94)
2027	800.58	0.77%	6.16	0.823%	6.59	-	(2.72)	(0.14)	(0.91)	(1.81)
2028	792.05	0.77%	6.10	0.823%	6.52	-	(2.72)	(0.14)	(1.05)	(1.67)
2029	783.28	0.77%	6.03	0.823%	6.45	-	(2.72)	(0.14)	(1.18)	(1.53)
2030	774.26	0.77%	5.96	0.823%	6.37	-	(2.72)	(0.14)	(1.32)	(1.40)
2031	764.88	0.77%	5.89	0.823%	6.29	-	(2.72)	(0.14)	(1.45)	(1.26)
2032	755.20	0.76%	5.74	0.823%	6.22	-	(2.72)	(0.14)	(1.59)	(1.13)
2033	745.20	0.76%	5.66	0.823%	6.13	-	(2.72)	(0.14)	(1.73)	(0.99)
2034	734.87	0.76%	5.59	0.823%	6.05	-	(2.72)	(0.14)	(1.86)	(0.86)
2035	724.19	0.76%	5.50	0.823%	5.96	-	(2.72)	(0.14)	(2.00)	(0.72)
2036	713.01	0.76%	5.42	0.823%	5.87	-	(2.72)	(0.14)	(2.13)	(0.58)
2037	701.44	0.75%	5.26	0.823%	5.77	-	(2.72)	(0.14)	(2.27)	(0.45)
2038	689.46	0.75%	5.17	0.823%	5.67	-	(2.72)	(0.14)	(2.40)	(0.31)
2039	677.06	0.75%	5.08	0.823%	5.57	-	(2.72)	(0.14)	(2.54)	(0.18)
2040	664.24	0.75%	4.98	0.823%	5.47	-	(2.72)	(0.07)	(2.61)	(0.11)
2041	650.85	0.75%	4.88	0.823%	5.36	-	(2.72)	(0.05)	(2.66)	(0.05)
2042	637.04	0.74%	4.71	0.823%	5.24	-	(2.72)	(0.04)	(2.70)	(0.02)
2043	622.81	0.74%	4.61	0.823%	5.13	-	(2.72)	(0.02)	(2.72)	-
2044	608.18	0.74%	4.50	0.823%	5.01	-	(2.72)	-	(2.72)	-
2045	593.15	0.74%	4.39	0.823%	4.88	-	(2.72)	-	(2.72)	-
2046	577.63	0.73%	4.22	0.823%	4.75	-	(2.72)	-	(2.72)	-
2047	561.77	0.73%	4.10	0.823%	4.62	-	(2.72)	-	(2.72)	-
2048	545.59	0.73%	3.98	0.823%	4.49	-	(2.72)	-	(2.72)	-
2049	529.13	0.73%	3.86	0.823%	4.35	-	(2.72)	-	(2.72)	-
2050	512.40	0.73%	3.74	0.823%	4.22	-	(2.72)	-	(2.72)	-
2051	495.39	0.73%	3.62	0.823%	4.08	-	(2.72)	-	(2.72)	-
2052	478.22	0.72%	3.44	0.823%	3.94	-	(2.72)	-	(2.72)	-
2053	460.92	0.72%	3.32	0.823%	3.79	-	(2.72)	-	(2.72)	-
2054	443.53	0.72%	3.19	0.823%	3.65	-	(2.72)	-	(2.72)	-
2055	426.08	0.72%	3.07	0.823%	3.51	-	(2.72)	-	(2.72)	-
2056	408.63	0.72%	2.94	0.823%	3.36	-	(2.72)	-	(2.72)	-
2057	391.24	0.72%	2.82	0.823%	3.22	-	(2.72)	-	(2.72)	-
2058	373.94	0.71%	2.65	0.823%	3.08	-	(2.72)	-	(2.72)	-
2059	356.76	0.71%	2.53	0.823%	2.94	-	(2.72)	-	(2.72)	-
2060	339.74	0.71%	2.41	0.823%	2.80	-	(2.72)	-	(2.72)	-
2061	323.00	0.71%	2.29	0.823%	2.66	-	(2.72)	-	(2.72)	-
2062	306.52	0.71%	2.18	0.823%	2.52	-	(2.72)	-	(2.72)	-
2063	289.87	0.71%	2.06	0.823%	2.39	-	(2.72)	-	(2.72)	-
Total			**1 000.81**		**1 000.37**					

h) The comment on lines 21-23 of page 43 of Tab 6 is incorrect. Typically, losses on the disposal of assets occur when assets are retired prior to reaching their expected service life and gains on the disposal of assets occur when assets are retired subsequent to reaching their expected service life. Lines 21-23 should have more appropriately read as follows:

Losses or gains on the disposal of assets is the net asset retirement amount for those assets retired prior to or subsequent to reaching their expected service life as determined under the ELG method of depreciation.

i) Throughout Manitoba Hydro's transition to IFRS, Manitoba Hydro has implemented accounting changes intended to minimize the impacts of IFRS on customer rates while also limiting the extent of growth in regulatory deferral accounts so as to avoid pushing today's financial burdens out to future generations, as discussed in Manitoba Hydro's response to MIPUG MFR 5.

The assumption to continue to defer the difference in depreciation expense between the ELG and CGAAP ASL methods until March 31, 2023, the final in-service date for the Keeyask generating station, recognizes that annual increases in export sales made possible by the capacity of the Keeyask plant will be more than sufficient to offset annual increases in depreciation resulting from the impacts of the transition to IFRS.

The depreciation related assumptions in MH16 do not reflect the CGAAP ASL method as a permanent regulatory depreciation method for financial reporting purposes. Consistent with the PUB directive in page 97 Order 73/15, Manitoba Hydro is continuing to use CGAAP ASL for rate-setting purposes until further Order of the PUB on this matter. As per page 97 of PUB Order No. 73/15:

Manitoba Hydro is to continue to use its existing Average Service Life methodology for calculating depreciation rates for rate-setting purposes until the Board is satisfied that a change in methodology is warranted.

Manitoba Hydro contends that an IFRS compliant ASL depreciation study would result in a similar increase to depreciation as determined under the ELG method.

j) The assumption to amortize the annual difference in depreciation expense over a 20 year period is viewed by Manitoba Hydro as a reasonable time period that would reduce the upfront impacts of IFRS on customer rates while also avoiding excessive growth in the regulatory deferral account. Consistent with Manitoba Hydro's response to MIPUG MFR 5, Manitoba Hydro is not supportive of extending the amortization periods of regulatory deferral balances so far into the future that future rate payers are left with the burden of absorbing excessively large regulatory deferral balances. Such circumstances would allow little room in future customer rates for other risks such as drought and higher interest rates. This concern is consistent with past concerns of the PUB with respect to aggressive capitalization and deferral policies as documented on pages 92 and 93 of PUB Order 116/08 which states:

> *"And, in this Order, the Board continues to be concerned with MH's "aggressive "capitalization and deferral policies with respect to OM&A expenses. While there is an argument for the practice, the net result is that costs now being incurred are not reflected in rates until years, in fact decades, later, meaning the current generation of ratepayers leaves the results for the generations that will follow to meet. The following concern, from Order 143/04, echoes past concerns raised by the Board with respect to the capitalization policies followed by MH. The Board then stated: ",… While the Board understands that many of the projects undertaken by MH are long-term in nature, both from a benefit and cost perspective, aggressively capitalizing costs and selecting long amortization periods increases the rate risks to future generations of electric customers"*

k) Please see Manitoba Hydro's response to PUB/MH I-17c which provides an explanation of the accounting requirements under IFRS for restructuring costs.

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Figure 5.3 summarizes the annual forecast over the 2016/17 to 2018/19 timeframe and the 10 year forecast period by executing projects, potential investments, programs and planning investments.

Figure 5.3 Summary of Electric Capital & Demand Side Management

($ Millions)	Total Project Cost	2017 Outlook	2018 Forecast	2019 Forecast	2018 - 2027 10 Year
MNGT					
Executing Projects	17 796	2 355	2 476	2 126	8 134
Electric Business Operations Capital					
Executing Projects	3 016	394	325	211	991
Potential Investments	425	-	-	6	391
Programs	NA	242	265	290	3 089
Planning Investments	NA	-	-	26	1 426
Portfolio Adjustments	NA	(63)	(64)	(16)	(303)
Unallocated Year End Outlook Adjustment - Electric		(45)			(45)
		529	526	517	5 549
DSM					
Electric Demand Side Management		50	56	99	752
Total Electric Capital & Demand Side Management	**21 236**	**2 934**	**3 058**	**2 742**	**14 435**

Investment Categories

Manitoba Hydro has incorporated the use of investment categories, which are commonly used within the industry to provide a better understanding of the primary driver for the investment. The primary investment categories are further broken down into sub-categories.

The primary investment categories are Capacity & Growth, Sustainment and Business Operations Support. Capacity & Growth investments provide for future load growth or address existing capacity constraints in key geographic areas on the transmission and distribution system. Sustainment investments are required to ensure the continued and future performance capability of the electricity system and address the issue of aging or obsolete assets. Business Operations Support investments support corporate operations including IT investments, fleet and administrative buildings. Further information on the investment categories can be found in Appendix D of the Capital Expenditure & Demand Side Management Forecast (CEF16).

REFERENCE:

PUB MFR 9 – Manitoba Hydro Corporate Risk Management Report, Section 3.7 – Other Significant and Emerging Risks, Page 17 of 95.

PREAMBLE TO IR (IF ANY):

Reputation

"The Corporation's reputation has been impacted by issues related to trust and transparency, rate increases, labour relations, and major projects (e.g. need, financial management, local reaction)."

QUESTION:

a) Please provide Manitoba Hydro's corporate assessment of cost benefit and probability / consequence associated with reputational risk.

b) What is the benefit to ratepayers of managing reputational risk?

RATIONALE FOR QUESTION:

What is the basis of equivalency for evaluating reputation risk versus monetary (and thereby safety / environmental) risk?

RESPONSE:

a) As discussed in the Reputation Risk Profile (PUB MFR 9 Revised, page 82), loss of reputation from a negatively public perceived event or series of events can significantly affect the Corporations's ability to achieve its overall strategic and operational goals, such as constructing a new generating station or transmission line that is required to provide safe and reliable energy service to customers. As of 2015 the Corporations's reputation had been impacted by issues related to trust and transparency, rate increases, labour relations and major projects. It was assessed that many of these challenges were likely to continue and others would probably emerge, such as new licencing requirements and Power Smart arrangements.

Manitoba Hydro assesses the likelihood and consequence of reputational risk in the Corporate Risk Rating Criteria matrix (PUB MFR9 Revised, page 94). The assessment of a negatively public perceived event or series of events will be dependent upon each event and can range from local media coverage of an event with negligible impacts to Manitoba Hydro or its customers to a highly visible event attracting international media attention and having significant impacts on stakeholders. The likelihood of such events ranges from low to high, respectively. As a result, the Corporation recognized there was a continuing need to focus on sustaining and enhancing corporate reputation through all its daily actions.

b) The benefit to ratepayers of managing reputational and other risks is the enhanced abilitly to achieve the Corporate mission and strategic objectives, including the ability to deliver safe, reliable energy services at a reasonable cost to ratepayers. Insofar as reputation damage impedes efficient engagement with numerous stakeholders it can add to capital and operating costs and therefore the burden on ratepayers.

REFERENCE:

Tab 5, Page 5 of 28; Technical Conference Transcript pg. 93, lines 16 – 18; PUB/MH I-119a-e

PREAMBLE TO IR (IF ANY):

In its response to PUB/MH I-119 (a), Manitoba Hydro states: " The overall target for Business Operations Capital takes into consideration the corporation's capital investment requirements, associated risks as well as current and future resource demands. These factors must be balanced with the need to maintain the financial strength of the company with funding through cash from operations, where possible. Targets for Business Operations Capital are then allocated to each of the major asset portfolios (generation, transmission, distribution and corporate infrastructure) with careful consideration for risk as well as current and future resource demands. Proposed adjustments are reviewed and approved by all impacted Vice-Presidents to balance operational priorities and risks."

QUESTION:

a) What is the meaning of "the corporation's capital investment requirements" as used in Manitoba Hydro's Response to PUB/MH I-119 (a)?

b) How is Manitoba Hydro able to ensure the PUB and ratepayers that the significant amount of base capital spending planned over the test period has been optimized? For example, have different capital spending scenarios (representing different project portfolios) and associated performance outcomes analyzed? If yes, please provide concrete examples.

RATIONALE FOR QUESTION:

To understand how Manitoba Hydro balances operational priorities across different operating groups.

RESPONSE:

a) “The corporation’s capital investment requirements” as used in Manitoba Hydro’s Response to PUB/MH I-119a refers to the amount of capital required to deliver on the corporation’s mission of creating value for Manitobans by meeting customer expectations for the delivery of safe, reliable energy services at a fair price.

The three operating groups have different, yet equally important, roles in delivering on the mission. Each group assesses risks to the mission in their operating context, as described in PUB/MH I-83. Mitigation, including capital investment, is undertaken to address unacceptable risks.

b) Optimization of capital investments in the test years is addressed in PUB/MH II-67. Capital investment scenario analysis is not part of the current optimization process. This functionality is included Capital Portfolio Management (CPM) program described in Section 5.1.3 of Tab 5 of the GRA.

The reviews and approvals of investments, portfolios and budgets described in PUB/MH I-119 and PUB/MH II-67 ensured that the capital spending in the test years is required as per the definition given above

REFERENCE:

Tab 5, Page 5 of 28; Technical Conference Transcript pg. 93, lines 16 - 18

PREAMBLE TO IR (IF ANY):

"As depicted in Figure 5.1, Programs are a collection of asset classes requiring renewal that are not planned on a specific asset basis, but rather as a fleet. Examples include large populations of comparatively inexpensive assets that require annual replacement for sustainability (e.g. wood poles), ongoing fleet life extension works (e.g. cable injection) and run to failure assets, such as pole top transformers."

QUESTION:

a) Please explain how Manitoba Hydro establishes optimal Capital Program budget envelopes for each business unit.
b) To what extent has Manitoba Hydro utilized its newly developed Asset Management methodology and processes in formulating the business unit CapEx and OpEx budget envelopes that comprise the present filing?
c) Are the budget envelope targets for the test years largely based upon "extrapolations from historic experience"?
d) How are projects prioritized and programs sized within the overall capital expenditure budget envelope?
e) Are project priority and program sizing decisions made using corporate level risk assessment criteria, or are they made at the business unit or regional levels, based upon asset condition assessment data (or some other criteria)? Please explain in detail.

RATIONALE FOR QUESTION:

RESPONSE:

a) The overall target for Business Operations Capital takes into consideration the corporation's capital investment requirements, associated risks as well as current and future resource demands. These factors must be balanced with the need to maintain the financial strength of the company with funding through cash from operations, where possible. Targets for Business Operations Capital are then allocated to each of the major asset portfolios (generation, transmission, distribution and corporate infrastructure) with careful consideration for risk as well as current and future resource demands. Proposed adjustments are reviewed and approved by all impacted Vice-Presidents to balance operational priorities and risks. On an ongoing basis, approved capital targets are reviewed at the Vice-President level to assess whether re-allocation of funds is required in order to balance operational priorities and optimize overall corporate value considering changes in business, financial and economic assumptions as well as operational risk factors. This iterative approach ensures a comprehensive decision making process that aligns operating unit priorities with overarching corporate objectives.

b) Manitoba Hydro is in the process of enhancing its Asset Management methodologies and processes for use in formulating future capital budgets. The capital and operating budgets in the current filing were not developed with the new Asset Management methodologies.

c) Capital budget targets for the 2016/17, 2017/18 and 2018/19 fiscal years were developed as described in part a), above. Beyond 2018/19, budgets were developed based on historic experience, extrapolations of trends and assessments of investment requirements.

Response to parts d) & e):

Projects and programs are prioritized and sized within Manitoba Hydro’s capital planning processes based on managing operational risks within the operating groups. Capital planning is performed across all three operating groups, using technical and management reviews as approval gates to manage and reevaluate investments as they progress through an investment’s life-cycle using the following processes.

i. Potential investment identification and development of alternatives by experienced operational personnel and subject matter experts

ii. Evaluation of alternatives and risk mitigation of investments by subject matter experts and management
iii. Approval and selection of investments to proceed to execution and selection of program funding levels by senior management
iv. Portfolio approval by the Vice-President
v. Execution of the portfolio of investments

While the fundamental steps are common, there is variation in the relevant operational risks being managed, as well as the tools and methods being used in each operating group.

As discussed in Tab 5, Section 5.1.2, the corporation is implementing the Corporate Value Framework as a tool to enhance Manitoba Hydro's capital investment decisions. The Corporate Value Framework helps identify the optimal set of investments that deliver the greatest value (or mitigates risk) to the organization, within funding, resource and timing constraints. This tool will be used to assess the value of capital investments across all areas of the corporation in support of allocating funds to projects and assets that optimize strategic value or mitigate risk.

Operational risk management and capital planning processes used to identify and prioritize the capital investments within CEF16 are described below for the major asset portfolios (generation, transmission and distribution).

Generation

Potential investments (which could include asset replacement, refurbishment, decommissioning, etc.) are identified within Generation and Wholesale in numerous ways. The majority of investments are identified through asset condition assessments. When the condition of an asset deteriorates to the point where it is nearing its economic end of life, it is considered for near term investment (typically a 3-7 year outlook). Asset performance is monitored and when the performance deteriorates to unacceptable levels, near term investment is considered. Changes in environmental conditions such as the arrival of an invasive species or legislation such as NERC CIP 5 Physical Security may also trigger the need for near term investment. Staff responsible for operating and maintaining the assets may identify an operational need that may warrant near term investment.

Annually, asset investment planners review, vet and prioritize known near term investment needs. Projects are created to address the highest priority near term investments. The list of projects is reviewed by the Generation and Wholesale Capital Planning Team and senior leadership. The Capital Planning Team consists of managers from operations, engineering and planning departments.

Prior to execution each potential investment typically passes through a scope development phase in which multiple solutions are identified and considered. For each potential solution a scope, schedule and budget are developed as well the value realized from each alternative is quantified.

The majority of the value realized from generation projects comes from mitigating risk. Value can also be realized by reducing or avoiding costs or increasing revenue.

Operational risk consequences typically fall into one of the following five categories:

i. Financial Risk– The vast majority of the financial risk is due to the potential of lost generation. Any one of a number of assets can fail and result in a generating unit being out of service which will result in lost revenue. Lost revenue is typically in the thousands of dollars per day and can easily range into many tens of thousands of dollars per day.
   A secondary source of financial risk is due to equipment damage. Occasionally when an asset fails it can result in damage to other assets. This consequential damage would not occur if the asset that failed had been replaced proactively. Particularly troublesome is the failure of an inexpensive asset resulting in damage to a critical asset.

ii. Compliance Risk – is the risk that Generation and Wholesale's operations will not be in compliance with legislation or internal policy. An example of compliance risk due to legislation is the risk that a waste water system failed resulting in the release of waste water exceeding legislated requirements for hazardous material concentrations

iii. Dam Safety Risk– is the risk that a water control structure will fail which could result in loss of life in downstream communities or outdoor recreational users (cottagers, fishermen, etc.) as well as negative impacts to the environment and financial consequences. Loss of life scenarios range from zero people to up to 200 people if a failure were to occur with no warning.

iv. Safety Risk – is the risk that an asset will fail and result in an injury or death to an employee or member of the public. Examples of this include catastrophic failure of a transformer or breaker that results in an explosion that could injure or kill people who happen to be in the vicinity or the failure of a guardrail on the powerhouses that also serve as highways which could allow a car to enter the river.

v. Environmental Risk – is the risk that an asset will fail and result in a negative impact to the environment. An example of this would be the failure of a hydraulic seal in a Kaplan turbine that could release large volumes of oil into the river.

Generation projects that are risk driven may mitigate risks from one or more of the above categories.

Generation and Wholesale quantitatively evaluates the financial and dam safety risks and qualitatively evaluates the compliance, safety and environmental risks. When quantitatively evaluating risk the probability of failure is calculated using one or more of the three following methods:

1. Use historical failure data for the risk in question.
2. Use asset health indices coupled with probability of failure curves that are both based on industry best practice.
3. When the above two methods are not possible, reliance on the many years of experience of senior technical staff and managers is utilized.

Senior technical specialists and the Capital Planning Team review the alternatives and the evaluation of value for consistency. The alternative for each project that is deemed to offer the highest value versus cost is selected for execution.

The Capital Planning Team compares all projects that are ready to begin execution and considers the value offered and resource availability to determine which projects to execute in the current year and which projects to execute in future years. The process is intended to maximize the value realized for each year.

The majority of Generation and Wholesale's programs are comprised of items for replacing or refurbishing run to failure assets. Program funding levels are determined based on historical failure and spending rates and the availability of resources.

Items to proceed to execution in each of the programs are considered annually. Program items are prioritized by the planners and senior technical staff based on the criticality of the asset, the risk mitigated and professional judgement. Each item within a program is justified and an approval document is prepared, reviewed and approved at the appropriate management level prior to execution.

A preliminary portfolio comprised of executing projects, those selected to begin execution, potential investments and an appropriate level of program investments is prepared for review and evaluation by the management team.

Capital Project Justification (CPJ) documents (now referred to as Capital Investment Justifications (CIJ) for each project are prepared by the project team and reviewed and approved by the Capital Planning Team and the appropriate level of management.

A final version of the portfolio, based on the aggregate of all approved projects and the programs is reviewed and approved by the Vice-President, Generation & Wholesale.

Transmission

Potential investments, which could include investments for system expansion and asset replacement or refurbishment, and decommissioning, have a number of different drivers and are identified in numerous ways. Transmission's Business Operations Capital is planned to ensure the transmission system meets the current and future energy needs of the province, in compliance with reliability standards, including the North American Electric Reliability Corporation (NERC) Planning Standards. As a member of the Midwest Reliability Organization (MRO), Manitoba Hydro complies with the NERC Transmission Planning Standards by completing an annual Transmission System Performance Assessment and submitting to the MRO a study report and documentation of any planned transmission system upgrades.

Concepts for capacity-related investment requirements are developed in response to the annual long-term provincial Electric Load Forecast, the annual Transmission System Performance Assessment and requests for generation interconnections, transmission usage and/or bulk load connection requests. These investments address potential equipment overloads and deteriorating system voltages associated with load growth, as well as the impacts of system expansion such as increased fault currents. Please see Coalition/MH I-158a-f for a description of system planning processes. These concepts are studied and refined into alternatives in consultation with various stakeholders, and the alternative that represents the best overall value to the customer is chosen for implementation as a capital investment project.

Potential sustainment investments are identified by the various maintenance groups based on asset performance (e.g. assets experiencing high rates of failure), sustainability (e.g. availability of spares or spare parts) and condition. Without these investments, there is an increasing likelihood of a failure that will result in an extended outage with reliability consequences and, if the asset fails catastrophically, has the potential for collateral damage to adjacent assets and/or the environment, and exposure of employees and/or the public to safety hazards. When an asset deteriorates to the point where it is nearing its economic end of life, it is identified as a candidate for near term investment while also considering available spares.. The assessment is done by experienced field staff that is responsible for operating and maintaining the asset in consultation, where applicable, with equipment/asset and reliability specialists.

Mandated compliance projects involve capital investments to address new regulations for reliability, safety and/or the environment, such as the introduction of NERC CIP 5 Physical Security or the requirement to remove all equipment with PCBs from service. These usually have fixed deadlines with financial penalties for non-compliance.

Capital investment requirements identified from the above factors are first documented in a planning study report, engineering report or technical memo or, for smaller scale investments, a report/justification prepared by a technical specialist. All planning study reports and engineering reports are reviewed by management. Investments that alter the transmission system are vetted at an early stage through the Concept Review Team, which is a peer review involving system planners, system operators, designers, constructors, project management, and asset owners. Project justifications are also documented and submitted for approval using CPJ documents. The review by Transmission management includes assessing the merits of the individual investment and its implementation plan, as well as consideration of priority within the overall Transmission portfolio.

Once capital projects are approved, they are eligible to be selected for execution through an annual prioritization process. The portfolio of active, future and proposed new investments is prioritized over the ten-year forecast window with the overall objective being to arrive at a portfolio of investments that could reasonably be achieved and represents the lowest overall risk profile that is possible within the available target. This annual prioritization process involves staff from System Planning, System Performance, Transmission Projects and HVDC Engineering.

In addition to the risks and benefits associated with each capital project, this assessment considers the operational risk mitigation strategies available to maintain the operability of the system where projects are deferred beyond the required-by dates specified in the planning reports. An example of operational risk mitigation is de-networking. De-networking is the intentional reconfiguration of the system to create radial feeds so that in the event of a contingency, load will be automatically shed to avoid violating mandated reliability criteria.

Transmission’s processes and tools for assessing risk and prioritizing capital investments under the Capital Expenditure Forecast are as follows:

- A ranking matrix is used to evaluate and score the relative importance of Transmission’s capital investments using common criteria for safety, service and reliability, transfer capacity, a positive financial impact, and/or a positive environmental impact. The probability of avoiding a risk or achieving a benefit is part of the project assessment. The ranking process involves determining which of these value factors are applicable to the project (e.g. which risks are mitigated by the project) and then assessing the probability and consequence associated with each of these factors based on a five level scoring framework. This assessment is done quantitatively where possible with available data or qualitatively based on the many years of experience of senior technical staff and managers. An explanation of the value factors considered in the ranking matrix is provided below:

  - Safety: the risk to public or employee safety from either people contacting energized equipment (e.g. contact with energized transmission line) or from catastrophic failure of equipment resulting in explosions, fire and/or projectiles.
  - Service & Reliability: the risk to customer supply or transmission system reliability due to unplanned outages on the system.
  - Financial Impact: a financial impact could either be a benefit, such as a reduction in operating and maintenance costs, or could be the mitigation of a risk, such as the potential risk of collateral damage due to the catastrophic failure of equipment. For example, the failure of an inexpensive asset or component can result in damage to an much more expensive asset.
  - Transfer Capability: the impact could either be an increase in system transfer capability, such as an increase in export capacity or the prevention of a loss of transfer capability.
  - Environmental Risk: the operation or failure of an asset may result in a negative impact to the environment. An example of this would be an oil spill due to the catastrophic failure of any oil filled apparatus in a station, particularly in cases where oil containment systems are not present.

- A project’s risk profile is assessed using the System Reliability Risk Model (i.e., the ΔEUE), which quantifies the risk in terms of potential impacts to the reliability of the transmission system. The tool models the operation of the transmission system with and without the additional or replacement assets for a given project or group of projects, and compares the expected unserved energy (EUE) for various potential failures on the related system network. Additional information about the System Reliability Risk Model (SRRM) is provided in response to Coalition/MH I-194a-g.

- A project's readiness to execute is also assessed based on such elements as the availability of internal labour resources, the status of licensing and property requirements, and the status of material delivery and construction contracts.
- The options available to mitigate the risks associated with deferral of a capital investment are evaluated. This considers the number of ways and ease with which operators can make real-time adjustments to the system in order to avoid dropping load or causing voltage issues until the capital investment has been implemented. In some cases the options are very limited, are complex to apply, or would introduce problems elsewhere on the system, such that they would be the option of last resort.

The above tools are used to triage all of the capital investments within the available annual targets (or in some instances, derive new annual targets) and a recommended portfolio is submitted to the Vice-President of Transmission for approval.

Distribution

Specific investments identified by Marketing & Customer Service are generally driven by customer requirements, system capacity requirements, asset health and both public and employee safety. Distribution planning and design studies are generated that offer an analysis to address the specific need for investment by comparing alternative approaches. The recommended approach is the most economic action that meets the stated objectives. These reports are sealed and issued by a professional engineer.

In addition, a risk evaluation review is undertaken annually at the senior management level where overall risk profiles are considered. The objective is to formulate a long term capital investment plan that also considers the aggregate risks inherent in the distribution system. The more significant risks are categorized as:

- System Capacity Risk: The risk that the distribution system(s) capacity may not be sufficient to meet customer requirements. The likelihood of consequences such as extended outages and inability to connect load growth is examined.
- Asset Component Failure Risk: The risk that the health of the distribution system assets could degrade to an extent that resulted in an unmanageable failure rate contributing to unacceptable distribution system reliability.
- Technological Advancement Risk: The risk that failure to keep up with industry technological advancements may compromise system reliability, safety and/or productivity.
- Damages to Plant Risk: The risk of employees, public and contractors coming in contact with infrastructure causing injury or damage.
- Public and Employee Safety Risk: The risk that the system is not adequately designed, operated and maintained in a manner that ensures employee and public safety. In addition, there is risk that employees and the public are not adequately informed to minimize the potential for injury.
- The Risk of not Meeting Customer Service Requirements: The risk that the distribution system is not capable of connecting new customers or accommodating customer load increases within a reasonable timeframe.
- Emergency Response Risk: The risk that Manitoba Hydro is not able to adequately respond to interruptions to service caused by weather and/or third parties.
- Regulatory/ Legal Compliance Risk: The risk that Marketing & Customer Service is not in compliance with safety and environmental regulations, contractual agreements and/or other legal obligations.

Project justification documents are supported by the aforementioned planning and design study including a review of viable alternatives along with an analysis of the key risk aspects. The likelihood and corresponding consequences associated with risks are generally derived qualitatively, relying on the knowledge and experience of senior technical employees applying distribution planning criteria (as applicable) in concert with any actual technical information that may be available. Information that may be utilized in a project's risk evaluation and subsequent consideration for execution includes; historical load recordings, customer service requests, asset age, and asset condition (as determined by visual inspection or testing).

Following a peer review within the planning area, individual CPJ's are advanced for consideration for the operating group portfolio.

The operating group portfolio is grouped into Programs (which "pool" similar and smaller investments into a single fund, and individual Projects that are required to address specific requirements. The resultant investment categories become:

- Capacity & Growth
  - System Load Capacity
  - Customer Connections – Residential, Commercial & Industrial
- Sustainment
  - System Renewal
  - System Efficiency
  - Mandated Compliance

Within M&CS, the investment categories of Capacity & Growth (i.e. Customer Connections and System Load Capacity) and Mandated Compliance are given the highest priority. Investments in other categories such as System Renewal and System Efficiency are then prioritized in accordance with the value creation and risk reduction as represented by value per investment dollar. Funding is then allocated to those projects as permitted by capital rationing. The major decisions on the ranking and funding allocation of investments largely occur through discussion amongst management personnel and the Capital Portfolio Governance Committee , represented by managers from operations, engineering planning and design, asset maintenance as well as finance and project/ contract management. The review includes a discussion of the technical, financial and resourcing aspects of the proposed investment.

The resultant proposed infrastructure investment plan is reviewed by the Capital Portfolio Governance Committee with the objective that this balanced capital portfolio will be the most effective approach to meet the requirements of the operating group.

The process is iterative as the funding allocated to each project or program also considers the technical urgencies associated with specific drivers and geographic areas. Short term priorities may change within the operating group, such as the requirement to accommodate urgent customer requirements or those of a technical urgency due to equipment failures or as budget limitations are prescribed. The Capital Portfolio Governance Committee reviews these impacts on the current capital portfolio and makes the required adjustments directing mitigation efforts to projects within the operating group posing greater risk to the corporation. Project scheduling constraints such as material delays and labour availability are also reviewed on a regular basis, and a short term re-prioritization of projects may take place to maintain effective utilization of resources.

Ultimately, the Capital Portfolio Governance Committee recommends individual projects and programs (as required), and the overall portfolio of investments to the Marketing & Customer Service Vice President for approval to move to the execution stage.

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REFERENCE:

Appendix 5.1 UMS Asset Management Gap Assessment Report of Findings to Manitoba Hydro Pages 34-36 of 48

PREAMBLE TO IR (IF ANY):

In its Asset Management Gap Assessment Report, the UMS Group identified a series of 28 recommendations (listed in the reference) to close the gaps identified in Manitoba Hydro's Asset Management capabilities.

QUESTION:

For each UMS recommendation, please provide the following information:

a) Plan: MH's implementation plan.
b) Schedule: The expected schedule for completing full implementation.
c) Status: The current status of MH's implementation plans. For any recommendations not being implemented, the status should include MH's justification for not accepting the recommendation.

NOTE: Please highlight any differences in implementation plans, schedules, and/or statuses across the business units: i) Generation, ii) Transmission and iii) Customer Service & Distribution.

RATIONALE FOR QUESTION:

UMS Group provided a comprehensive list of asset management gaps and necessary next (but not final) steps to advance MH's asset management process maturity. This IR is to determine status of MH's implementation plans.

RESPONSE:

Response to parts a) through c):

The UMS Asset Management Gap Assessment was performed as Phase 1 of Manitoba Hydro’s Corporate Asset Management initiative, as described in Section 5.1.1 of Tab 5 of the GRA. Phase 3 of the initiative is to develop an implementation roadmap within which UMS’ specific recommendations will be considered for implementation. The development of an implementation roadmap in Phase 3 will be initiated following the completion of Phase 2, which includes the development of asset management policies and strategies. Implementation of Phase 2 has not commenced due to competing organizational priorities and the voluntary departure program. The key milestones within Phase 2 include asset management training sessions, drafting and finalization of asset management policies and the finalization of an asset management strategy. A timeline for initiating Phase 2 and has not been finalized.

REFERENCE:

Tab 5, Page 12-13 of 28.

PREAMBLE TO IR (IF ANY):

"A roadmap is currently under development for achieving these objectives. The roadmap will detail the steps needed to deploy corporate tools and processes, build supporting sub-processes and data structures, populate asset inventories and collect data, and build proficiency in the user groups. The anticipated timeline to achieving the objectives is three to five years."

QUESTION:

a) Is Manitoba Hydro's plan to have implemented a fully functional Asset Management process in 3 to 5 years?
    i. If yes, has the referenced implementation roadmap now been developed against which MH progress towards this goal can be measured in future rate applications? If yes, please provide this roadmap.

b) Please identify the major gaps that must still be bridged to enable Manitoba Hydro to achieve a comprehensive Asset Management process implementation, corporately and by business unit.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro's plan for implementing a Corporate Asset Management framework will be developed as Phase 3 of its Corporate Asset Management initiative, as described in Section 5.1.1 of the General Rate Application. As such, the schedule for building asset management processes has not been defined. Manitoba Hydro expects that the implementation plan will include several deliverables and milestones that will be achieved in a 3 to 5 year timeframe; however it is expected that with the continuous updates in methodologies and developments in asset management within the utility industry, there will always be additional development and improvements which may be achieved beyond this timeframe.

The roadmap discussed in Section 5.1.3 of Tab 5, Pages 12-13, refers to attaining Manitoba Hydro's asset investment planning objectives of optimizing the timing of investments to maximize value and forecasting long term corporate capital requirements. Asset investment planning (also commonly referred to as capital expenditure planning) is one component the larger Corporate Asset Management Framework, which is described in Section 5.1.1 of Tab 5 of the GRA.

b) Please see Appendix 5.1 for the gap assessment of Manitoba Hydro's current asset management practices as compared to industry best practices as well as the ISO 55000 and PAS55 standards that was performed by the UMS group.

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REFERENCE:

Appendix 5.1 UMS Asset Management Gap Assessment Report of Findings to Manitoba Hydro Page 7 of 48; PUB/MH I-67a-d

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB/MH I-70 (b)

"As of the July 2017 all three operating groups are now applying this [Copperleaf CVF] quantitative approach to assess all benefits and risks for newly proposed potential investments."

Reference: Manitoba Hydro Response to PUB/MH I-87 (c)

"Manitoba Hydro intends to make its Asset Management processes between Operating Groups and areas consistent at the overall corporate level through the use of templates and common evaluation criteria … and the consistent risk assessment evaluations will be completed as part of the Corporate Asset Management Framework initiative. The timeline for these processes to be established and consistently utilized is three to five years."

Reference: PUB MFR 107

"capital investments are evaluated using the Corporate Value Framework. The Corporate Value Framework is a systematic framework to understand the value of all investments in an organization ... The Corporate Value Framework assesses values in five streams: financial, environmental, reliability, corporate citizenship, and safety & security. Within these streams, there are 27 measures linked to benefits and risks that impact reliability and performance.”

QUESTION:

a) In accordance with the Value Framework Implementation document (Attachment 1 of PUB MFR 107), please explain how Manitoba Hydro is planning on implementing C55 in all groups by year-end 2017 if there is no common risk definition between groups?

b) Once implemented in all groups, will C55 govern decision making for all asset investments in Manitoba Hydro and reflect Manitoba Hydro's corporate policy, strategy and objectives for asset management? Please explain.

c) If the response to (b) is no:
   i. Pease define the deficiencies Manitoba Hydro has identified in Copperleaf's Value Framework Implementation document "Value Function" (Table in Section 7.2 of the Copperleaf report), including a quantitative description of the difference by providing a comparison between current Manitoba Hydro values for each of the three operating groups and Copperleaf's suggested quantitative values.
   ii. Please explain why the corporate policy, strategy and objectives (being implemented on a yet to be determined schedule) for asset management are being set after, rather than before, implementing a decision tool for all asset investments in all operating groups at Manitoba Hydro.

RATIONALE FOR QUESTION:

To understand how the Copperleaf Value Framework Implementation Document including CVF will interface with the development of the corporate policy, strategy and objectives document.

RESPONSE:

a) The Corporate Value Framework (CVF) provides a tool for common assessment of risk between groups for use in evaluating potential investments by defining nine levelled consequence definitions for 14 risk value measures. Risk evaluation in the CVF is described in Section 6 of Manitoba Hydro Value Framework Implementation Document (VFID), filed as Attachment 1 to PUB MFR 107.

Using the CVF, scenarios are analyzed by experienced operations personnel and technical experts to assess risk (probability x consequence). Probability of occurrence is estimated based on best available information for the given scenario and consequence values are selected from the definition levels described in the VFID (referenced above).

b) C55 is the tool that will underpin asset investment planning at Manitoba Hydro and provide the functionality for analysis and management of investments, including workflows for gated approvals. Investment decisions will be made by technical staff and line management in progression as potential investments are identified and progressed through to execution (see section 5.1.2 of Tab 5 of the GRA) with approval at appropriate management levels as detailed in PUB MFR 105. Inputs to those decisions will include the analysis performed within C55, evaluation of the potential investment within the Corporate Value Framework, constraints and other contextual considerations. These decisions will be guided by and will align to the company's asset management policy, strategy and objectives.

c) i. Manitoba Hydro subject matter experts from all Corporate and Operating Groups worked with Copperleaf to establish the value functions within the table in Section 7.2 of the Copperleaf Value Framework Implementation Document. Manitoba Hydro agrees with the quantitative values of the value measures and deems them to be appropriate for the first iteration of the Corporate Value Framework.

ii. The development of the Corporate Value Framework was initiated as an investment decision process improvement under the Capital Portfolio Management Program. The program was already in flight with significant progress when the Corporate Asset Management initiative was launched. The CPM constitutes the larger processes and tools needed for investment portfolio management. Delaying the program and deferring the associated process improvements, in anticipation of aligning the CVF (which is a decision support tool within the CPM) to corporate asset management policy, strategy and objectives was undesirable and unnecessary as the CVF can be calibrated to reflect any changes.

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Asset Management Gap Assessment

Report of Findings to Manitoba Hydro

Conducted by

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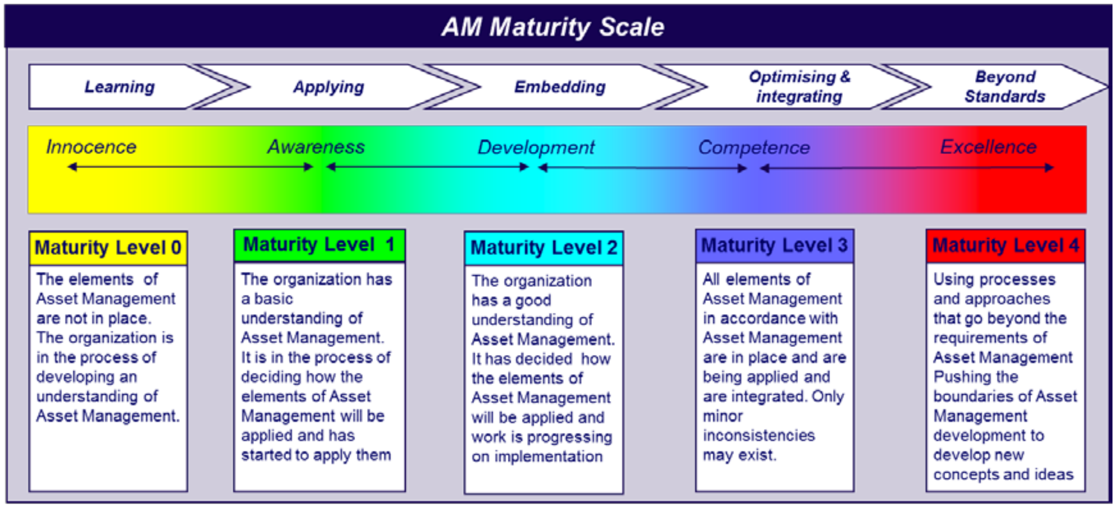
Parsippany, NJ 07054

December 15, 2016

EXECUTIVE SUMMARY

Using the methodology described in the *Introduction* above, UMS Group assessed Hydro against ISO 55000 and best practice Asset Management on the following scale:



Notes on the use of the maturity scale:

1 As indicated by the colour transitions, the boundaries of the maturity scale are not hard values

2 Compliance with the AM Standard is at Competence maturity level 3

3 There is no upper limit to excellence as defined by the red colored zone

Overall, Hydro scored a 1.5 with the individual Business Unit Scores as follows: Generation Operations (GO) = 1.7, Transmission = 1.6, and Customer Service & Distribution (CS&D) = 1.3. While these scores may seem low compared to a competence standard of 3, it is important to realize that many North American utilities would rate a 0 (unaware of major Asset Management System requirements) or a 1 (aware of, but not yet developing). In addition, the individual components which make up these average scores ranged from 0.5 to 3.0 corresponding to the fact that while Hydro is fully Competent in some areas, there are others where it is just starting to develop its capabilities.

Against the industry, Manitoba Hydro compares favorably versus North American utilities in terms of its Asset Management maturity level. However, North America lags global Asset Management best practice as embodied by utilities overseas who have been developing their capabilities for more than two decades.

Hydro has followed a typical path along the Asset Management maturity curve by starting with grassroots-led tactical solutions to solve specific problems. As with many utilities, the initial role Leadership played at Hydro with regard to Asset Management has been providing approval and direction when requested. If Hydro seeks to become an asset management-focused company, Leadership will want to place a greater emphasis on the strategic value of asset management, challenge progress within the Business Units, demand accountability for results, and commit the resources needed to achieve its objectives.

Between the three Business Units, Hydro has developed a number of the key components of best practice asset management such as:

- The development of Asset Health Indices (AHIs) and use of Condition Assessment to drive replacement decisions;
- The use of risk (likelihood x consequence), rather than just criticality (consequence) to drive some replacement decisions;
- The use of Reliability Centered Maintenance (RCM) to develop maintenance plans based on specific asset failure modes; and
- The development of Computerized Maintenance Management Systems (CMMS) to tie together asset data, maintenance data, and cost information

In addition, Hydro has already identified a number of existing gaps and plans/actions to close these gaps are underway including:

- The recent adoption of a monetized risk-based decision-support tool for capital planning -- Copperleaf's C55 and the Corporate Value Framework (CVF);
- An alliance with Siemens which aims to develop sophisticated capabilities for managing, maintaining, and evolving Distribution assets; and
- A new CMMS (SAP Plant Maintenance (PM) – Enterprise Asset Management (EAM)) to improve the ability to tie costs to assets

However, there are also a number of key gaps which UMS Group has identified and for which no current initiative is underway to close. Below is a summary of these key gaps along with corresponding key recommendations. A detailed assessment which describes all gaps and all recommendations is provided in the following *Assessment* section.

Key Gaps

The Business Units, and sometimes the functions within the Business Units, have been operating with their own objectives and limits for making asset decisions, as there is confusion over the Asset Owner role. While the Corporate Asset Management Executive Council (CAM EC) has been chartered with most of the responsibilities of the Asset Owner, this role has not been formally communicated to the organization, nor have the Business Units been provided with concise direction on Policy, Strategy, and Objectives, although the CAM does have a plan to develop these over the next few months.

Responsibilities for Asset Management are divided with a lack of clear understanding of what constitutes the Asset Manager and Service Provider roles, as well as what the responsibilities and accountabilities of each are. In addition, the fact that Asset Management has developed independently in each Business Unit and that the Asset Management functions are split within the Business Units has led to a lack of standardization of processes (and systems) and hindered the sharing of best practices.

Risk is a key basis for decision-making in best practice asset management systems and Hydro is increasingly incorporating risk in its asset-related decisions today. However, there are no corporate risk standards, tolerance levels, or risk assessment requirement to guide the Business Units leading to a situation in which risk is being avoided rather than managed.

Some of the key elements of an Asset Management System are missing from Hydro today. These include audits, controls, and performance metrics which Leadership can use to ensure the suitability, adequacy and effectiveness of the system.

Different functions within each business unit have different roles in the asset life-cycle leading to a situation where no one group or function is responsible for optimizing total asset life-cycle cost. In addition, most asset management efforts are focused on Capital spending with minimal attention given to optimizing O&M, which is a key part of the asset life-cycle.

While significant effort is being made to develop and implement sophisticated tools to support Asset Management, there is a lack of formal Data Management and Governance processes and metrics to ensure that sufficient data of sufficient quality is available to use with those tools.

Performance Management at Hydro is currently focused more on compliance than on driving improvement with few metrics available to identify opportunities to continually improve the asset management system.

Key Recommendations

Formally acknowledge the CAM EC's role as the Asset Owner by designating it such with the authority to oversee and approve the development of asset management policy, objectives, risk tolerance, and financial constraints and communicating this role to the organization.

Provide communication on acceptable risk for Manitoba Hydro by defining a risk tolerance level for key strategic objectives, defining a corporate standard for risk assessment, and creating a corporate standard risk register. Establish a formal process to regularly review risks identified by the business units and provide direction as a result of the review.

Decide on and declare the Operating Model for Asset Management – roles, decision-making processes, goals and key performance indicators (KPIs), and the timetable for implementing these changes.

Formalize the Asset Manager and Service Provider roles and clarify accountabilities with regard to responsibilities within the key asset management processes. Group the functions focused on asset management to create a life-cycle orientation in decision-making. Create an Asset Strategist role with overall responsibility for the integrated Asset Life-cycle Strategy. Use this role to develop and document Life-cycle Strategy Plans for key asset classes to optimize total cost

Develop processes and implement tools to address Operations & Maintenance (O&M) spend and the trade-off between O&M and Capital in each business unit. Establish the preeminent role of the Asset Manager in making maintenance decisions, in terms of whether the maintenance is justified by cost versus benefit.

Develop a robust data governance structure to ensure data integrity and validity, and to enable effective data analysis for making asset-related decisions. Identify needed data to support asset management decision-making and assess where data repositories, data collection methodologies, data quality, etc. are out of alignment with needs.

Refine the current Performance Management framework to align asset objectives, plans and KPIs with performance reporting and accountability. Develop metrics for monitoring asset performance, asset management performance, and asset management system performance.

Develop controls and an internal review function for the asset management system to ensure corporate and business-unit level processes and procedures are being followed.

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REFERENCE:

Business Operations Capital and Asset Management Technical Conference Transcript, July 20, 2017, Pages 130 - 132

PREAMBLE TO IR (IF ANY):

Reduction of volitional capital expenditures to mitigate the rate impacts of Major Project costs.

QUESTION:

a) Please provide a detailed list of all project and program expenditures that have been deferred from the test years to mitigate the rate impacts of Major Projects.

b) Has Manitoba Hydro evaluated different investment scenarios for the test years, to determine the relative performance outcomes that would be expected at different levels of capital investment and different mixes of investment between the different business units?

   i. If yes, please provide any reports or evaluations that were done.

   ii. If no, please explain how Manitoba Hydro can be confident that the filed test year capital expenditures are optimal, and maximize ratepayer value.

RATIONALE FOR QUESTION:

RESPONSE:

a) In order to mitigate the impacts of the increased costs for the major capital projects, the reduced outlook for domestic load growth and the continued delay in recovery of opportunity export pricing, the business operations capital target was reduced in the test years as part of the corporation's cost reduction plan. The capital targets that were set for the test years considered the overall financial strength of the corporation in balance with the need for capital investment requirements, associated risks and future resource demands.

No projects or programs identified for execution in the test years were deferred expressly to offset the impacts of major projects. Instead, the priority of potential investments was re-evaluated and the operating group's investment portfolios were re-prioritized based on the revised capital target.

b) Manitoba Hydro did not explicitly evaluate alternative investment scenarios for the test years to determine the relative performance outcomes from different levels and allocations of investment between the operating groups.

Capital investments that maintain reliability and safeguard against unacceptable risks are necessary to maintain Manitoba Hydro's financial strength and provide long-term value for the ratepayer. The re-evaluation and re-prioritization of investments within business operations capital was conducted to derive an optimal level of capital expenditures. The process used to do this is described in PUB/MH I-119a.

REFERENCE:

Coalition/MH I-145a

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table breaking down the CEF16 and CEF15 Business Operations Capital Spending into Generation & Wholesale, Transmission, Marketing & Customer Service (Distribution), Human Resources & Corporate Services, and Finance & Strategy. Please show the changes in each category between CEF15 and CEF16.

RATIONALE FOR QUESTION:

RESPONSE:

The table below provides a comparison of CEF16 to CEF15 for Business Operations Capital spending into Generation & Wholesale, Transmission, Marketing & Customer Service, Human Resources & Corporate Services and Finance & Strategy from 2016 through 2037.

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10-Year Total	2017-2036 20-Year Total
Generation & Wholesale														
CEF16	-	103	95	100	110	110	115	135	135	143	146	149	1,237	2,819
CEF15	120	122	132	132	132	132	135	137	140	143	146	149	1,377	2,978
Change Inc/(Dec)	(120)	(19)	(37)	(32)	(22)	(22)	(20)	(2)	(5)	-	-	-	(140)	(159)
Transmission														
CEF16	-	130	132	134	140	140	140	140	140	150	150	159	1,425	3,139
CEF15	137	150	125	125	125	150	150	150	150	153	156	159	1,443	3,177
Change Inc/(Dec)	(137)	(20)	7	9	15	(10)	(10)	(10)	(10)	(3)	(6)	-	(18)	(38)
Marketing & Customer Service														
CEF16	-	272	243	235	220	215	191	218	222	265	262	267	2,339	5,427
CEF15	245	272	235	210	210	210	214	218	222	265	262	267	2,314	5,402
Change Inc/(Dec)	(245)	-	8	25	10	5	(23)	-	-	-	-	-	25	25
Human Resources & Corporate Services														
CEF16	-	68	55	55	55	55	56	57	58	60	61	62	574	1,258
CEF15	75	65	55	55	55	55	56	57	58	60	61	62	574	1,255
Change Inc/(Dec)	(75)	3	-	-	-	-	-	-	-	-	-	-	-	3
Finance & Strategy*														
CEF16	-	-	-	-	-	-	-	-	-	-	-	-	2	5
CEF15	-	-	-	-	-	-	-	-	-	-	-	-	2	5
Change Inc/(Dec)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unallocated Target Adjustment														
CEF16**	-	(45)	-	(8)	(10)	(9)	(2)	(30)	(12)	(3)	22	22	(29)	142
CEF15	-	-	-	25	25	25	-	-	-	-	-	-	75	75
Change Inc/(Dec)	-	(45)	-	(33)	(35)	(34)	(2)	(30)	(12)	(3)	22	22	(104)	67
Totals														
CEF16	**-**	**529**	**526**	**517**	**516**	**511**	**499**	**521**	**544**	**616**	**640**	**659**	**5,546**	**12,790**
CEF15	**577**	**610**	**547**	**547**	**548**	**573**	**555**	**563**	**571**	**621**	**624**	**637**	**5,786**	**12,892**
Change Inc/(Dec)	**(577)**	**(81)**	**(22)**	**(31)**	**(32)**	**(61)**	**(55)**	**(42)**	**(27)**	**(6)**	**16**	**21**	**(240)**	**(102)**

* The annual CEF15 & CEF16 forecast for Finance & Strategy from 2016 to 2027 was $0.2 million

** (45) million in 2017 reflects the year end Outlook Adjustment

REFERENCE:

Tab 5, Page 7 of 28; PUB/MH I-85a-b

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the quantitative analysis done to support the ratio of distribution to transmission to generation capital investment levels.

a) How does Manitoba Hydro ensure that the proposed Capex plan has been optimized?

b) Has Manitoba Hydro done any predictive reliability analysis to validate the anticipated performance improvements of the Capex plan? If so, please provide details.

c) Does Manitoba Hydro's analysis of the future needs considered when creating the project portfolios comprising the filed capital plans incorporate the anticipated significant improvements in generation capacity and transmission capacity that will be delivered by the Keeyask and Bipole III projects?

RATIONALE FOR QUESTION:

RESPONSE:

a) The optimization of budget allocations is addressed in Manitoba Hydro's response to PUB/MH II-67.

b) Manitoba Hydro capital targets are extrapolated from past investment requirements and escalated to account for a growing and aging asset base with the objective of maintaining historic levels of service. Predictive reliability analysis is not performed within the current capital planning process.

As indicated in the response to Coalition/MH II-63a, Manitoba Hydro does monitor its level of service against like utilities within the Canadian Electrical Association to gauge performance.

c) Transmission and Generation & Wholesale both considered the impact of the Keeyask Generating Station and Bipole III on system capacity when creating the capital portfolio for the test years.

Marketing & Customer Service did not consider the addition of the Keeyask Generating Station and Bipole III in capital planning for the distribution system as these additions have no effect on current or future capital investment requirements.

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REFERENCE:

Appendix 5.1 UMS Asset Management Gap Assessment Report of Findings to Manitoba Hydro Page 7 of 48; PUB/MH I-68a-c

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB/MH I-70 (b)

"As of the July 2017 all three operating groups are now applying this [Copperleaf CVF] quantitative approach to assess all benefits and risks for newly proposed potential investments."

Reference: Manitoba Hydro Response to PUB/MH I-119 (b) and (c)

"The capital and operating budgets in the current filing were not developed with the new Asset Management methodologies. ... Beyond 2018/19, budgets were developed based on historic experience, extrapolations of trends and assessments of investment requirements."

QUESTION:

a) Please confirm that there is little coordination of risk evaluation across the operating groups. If not confirmed, please provide examples from each operating group demonstrating coordination.

b) Please explain how it can be considered optimal to have projects with similar risks (risk = probability x consequence) evaluated differently across different operating groups?

c) When Manitoba Hydro has implemented C55 in all operational groups by year end 2017, will risk be consistently valued and assessed across the three operating groups?
    i. If yes, please provide details.
    ii. If no, why not?

d) Since capital and operating 'budgets were developed based on historic experience, extrapolations of trends,' please justify how the current budget forecasts accurately optimize the assessment of 'benefits and risks for newly proposed potential investments.'

RATIONALE FOR QUESTION:

To understand how each operating group is left to decide its own level of risk acceptance.

RESPONSE:

a) Manitoba Hydro's previous processes did not include or require quantitative levelling of risk across Operating and Corporate groups. However, with the implementation of the Capital Portfolio Management program, Corporate Value Framework and C55 risk is now being evaluated consistently as part of the investment justification and evaluation process. Please see response to PUB/MH II-65a for a description of this consistent risk evaluation process.

b) Optimization within previous practices is addressed in Manitoba Hydro's response to PUB/MH II-67.

A common risk scale for evaluating potential investments across Corporate and Operating groups was one of the objectives of the Capital Portfolio Management (CPM) program, which includes deployment of the Corporate Value Framework and C55. Please see response to PUB/MH II-65a for a description of this consistent risk evaluation process being utilized under the CPM.

c) When C55 has been implemented in all operational groups, risk will be consistently valued as described in the response to PUB/MH II-65a. However, Manitoba Hydro does not expect to be mature in the application of its Capital Portfolio Management program and Corporate Value Framework practices and processes once first implemented. Manitoba Hydro will continue to improve these processes which will include calibrating the Corporate Value Framework to asset management policies and strategies once developed. The timeline for this process is 3–5 years.

d) Optimization of budget allocations is addressed in Manitoba Hydro's response to PUB/MH II-67. This process is based on an assessment of the risks associated with unfunded potential investments at given budget allocation levels, which is a near term outlook (i.e. a few years). The longer term capital budget outlooks are also informed by this process, but are anchored in the historic capital investment needed to sustain system assets.

As stated in Tab 5 of the GRA and PUB/MH I-86a-b, Manitoba Hydro expects to achieve its objectives of optimizing portfolios and forecasting long term corporate capital requirements within 3 to 5 years. During this time, maturing analysis processes will provide a longer outlook and more thorough assessments of the risks associated with the unfunded potential investments. Budget allocations amongst the Corporate and Operating Groups are revisited annually and informed by theses assessments, as noted in PUB/MH II-67. The budget allocation process is expected to evolve with the maturing planning processes to support longer term budget optimization.

REFERENCE:

Appendix 5.1 UMS Asset Management Gap Assessment Report of Findings to Manitoba Hydro Page 16 of 48; Tab 5 - Page 9 of 28; PUB/MH I-69a-b

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB-MH-I-119 (a)

"Targets for Business Operations Capital are then allocated to each of the major asset portfolios (generation, transmission, distribution and corporate infrastructure) with careful consideration for risk as well as current and future resource demands."

Reference: Manitoba Hydro Response to PUB-MH-I-74 (a)

"the vastly different purposes, perspectives and application of the two reports lead to an incompatibility in the specific definitions. The Corporate Risk Management Report is created to provide Manitoba Hydro’s stakeholders with a broad update about the status and trends within the business environment, and the major risks facing the corporation in the short to medium term. The Corporate Value Framework is used to evaluate and optimize investments for the organization."

Reference: Manitoba Hydro Response to PUB I-68 (a)

"High level risks and risks that affect business continuity are reviewed at the Corporate level, and the Manitoba Hydro Executive Committee and the Manitoba Hydro-Electric Board determine the level of acceptable risk and evaluate potential mitigation efforts. The required mitigation efforts and specific operational risks are delegated to the Operating Groups to be managed based on their knowledge of the system, processes and historical experience."

Reference: Manitoba Hydro Response to PUB I-69 (a)

"Risk is measured and comparatively assessed for projects and programs within the capital planning processes as described for each of the operating groups"

QUESTION:

Since Operating groups are first assigned budgets by the corporate group with "vastly different purposes, perspectives and application", then risks and investments are assessed comparatively solely within their Operating group silos, and then projects are executed until the budget is fully consumed, please explain how budgets are optimized between Operating Groups.

RATIONALE FOR QUESTION:

To understand how investments and budget (which includes risk and risk mitigations) are valued consistently across all four groups (Corporate and the three operating groups).

RESPONSE:

Manitoba Hydro's responses to the first round IRs quoted in the preamble to this IR require some clarification, to which the following is offered.

While the comment regarding "vastly different purposes, perspectives and applications" was made in contrasting two disparate reports, the operating groups do have different yet equally important roles to play in delivering energy to the customer. As described in PUB/MH I-83a, energy delivery to the customer is generally only at risk when considering an outage on the distribution system. Provided the system is operating within normal parameters, the consequences of a generator outage are limited to lost revenue and the consequences of an outage on the transmission system are limited to lost reliability and operating flexibility.

Despite these differences, the processes used for setting the Operating and Corporate Groups targets for Business Operations Capital and Capital planning for the test years are consistent and described in PUB/MH I-119. Work is well underway to deploy updated and improved processes for optimizing capital portfolios within each group. These improvements are part of the overall Capital Portfolio Management program as described in Section 5.1.3 of the GRA.

Capital planning is performed across all operating groups, using technical and management reviews as approval gates to manage and reevaluate investments as they progress through an investment's life-cycle using the five consistent processes described in parts d) & e) of PUB/MH I-119. Each group utilizes these consistent processes as well as tools and methods developed by each respective operating group to assess and manage their individual operational risks within funding and resource constraints.

Budgets are applied as a planning constraint in prioritizing projects within the portfolios after each of the projects has passed through approval gates of technical and management review. Thus, work is only initiated on projects with appropriate justification.

Further, the imposed constraints do not allow for all identified potential investments to be executed, leaving a large body of potential investments in abeyance. The risks associated with the unfunded potential investments are assessed annually for consideration in the corporate and operating group portfolios. On this basis, approved capital targets are reviewed at the Vice-President level to assess whether re-allocation of funds is required in order to balance operational priorities and optimize overall corporate value considering changes in business, financial and economic assumptions as well as operational risk factors. Any proposed target adjustments are reviewed and approved by all impacted Vice-Presidents to balance operational priorities and risks.

REFERENCE:

Appendix 5.3 – Manitoba Hydro Asset Condition Assessment Audit by Kinectrics – Section VI – Results and Findings for Each Asset Category, Page 126 of 287; PUB/MH I 97a-b

PREAMBLE TO IR (IF ANY):

Figure 7-1 of PUB/MH I-97a-b shows:

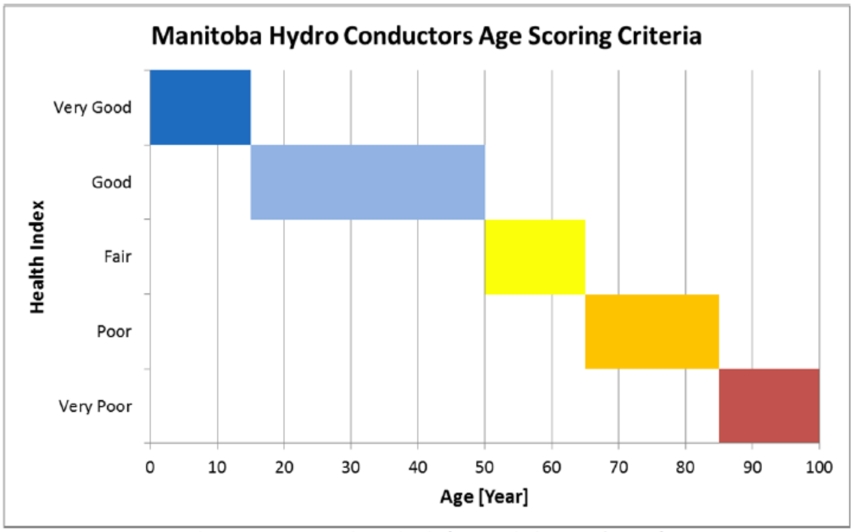


Figure 7-1 Age Scoring Criteria (Transmission Conductors)

QUESTION:

Did Manitoba Hydro use the results of condition analysis of its own assets in developing the age and condition relationship for conductors shown in Figure 7 1?

If yes, please provide the analysis.

If no, please provide the basis for this relationship.

RATIONALE FOR QUESTION:

RESPONSE:

The age and condition relationship for transmission line conductors shown in this figure was not developed based on a condition analysis of Manitoba Hydro's assets. The expected life of transmission line conductor was estimated to be 85 years based on a study done by a Canadian utility, which estimated an average service life of 77 years for a comparable region, and on Manitoba Hydro's knowledge of the performance of its transmission line conductor assets. The 85 year expected life was used as the boundary of the Very Poor category, and the age ranges associated with the remaining categories were selected based on engineering judgment.

REFERENCE:

PUB MFR 92 Attachment 1 – Manitoba Hydro 2016 Asset Condition Assessment by Kinectrics – Executive Summary, Page vi of 260; PUB/MH I-98a-c

PREAMBLE TO IR (IF ANY):

In its response to PUB/MH I-98 (b), Manitoba Hydro states: "There are no maintenance records for overhead switches. Currently switches are run to failure assets. Maintenance requirements are being evaluated for this asset."

In its response to PUB/MH I-98 (c), Manitoba Hydro states: "Marketing and Customer Service (M&CS) will strive to implement a "best practice" asset management methodology for the asset types for which only age data is available."

QUESTION:

a) Is it Manitoba Hydro's standard practice to not keep maintenance records for run-to-fail assets?
    i. Please define which run-to-fail assets have maintenance records and which do not.
    ii. For assets with no maintenance records, why are records not kept?

b) Does Manitoba Hydro record the cause of failure for run-to-fail assets? If yes, please provide these records for the last 5 years.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro does not keep maintenance records for most run-to-fail assets.

    i. The following assets are currently considered "run-to-failure" and have the following maintenance activities:

- Polemount transformers are visually assessed during detailed feeder inspections for signs of corrosion and oil leakage. Deficiencies are noted in Distribution Maintenance Planning System (DMPS).
- Ductlines are not inspected, maintenance records are not kept, and run to failure.
- Underground cables are run to failure with the following exceptions. Cross-Linked Poly Ethylene (XLPE) cables undergo testing and silicone injection to prolong life. Paper Insulated Lead Covered (PILC) cable splices and potheads are inspected for signs of leakage during manhole, station, and vault inspections and repaired. PILC cables installed on lateral poles are run to failure without inspections. Tree-Retardant Cross-Linked Poly Ethylene (TRXLPE) cables are not tested, nor do they receive maintenance.

ii. Records have not been historically kept for some run-to-fail assets for the following reasons:
   - In the case of ductlines, technology has only recently become available to video “scope” the inside of ductlines to assess condition.
   - In the case of TRXLPE cables, Manitoba Hydro has not had a high number of failures with this sub-asset class. In addition, current injection technology is not suitable for Manitoba Hydro’s TRXLPE cables. The cable design utilizes a solid-core design (1/0) and strand blocking materials for larger cable sizes.
   - In the case of PILC lateral cables, there have been limited failures involving this sub-asset class.

b) Manitoba Hydro does not record the cause of failure for run-to-fail assets.

REFERENCE:

PUB MFR 92 Attachment 1 – Manitoba Hydro 2016 Asset Condition Assessment by Kinectrics – Executive Summary, Page vi of 260; PUB/MH I-98a-c

PREAMBLE TO IR (IF ANY):

In its response to PUB/MH I-98 (b), Manitoba Hydro states: "There are no maintenance records for overhead switches. Currently switches are run to failure assets. Maintenance requirements are being evaluated for this asset."

In its response to PUB/MH I-98 (c), Manitoba Hydro states: "Marketing and Customer Service (M&CS) will strive to implement a "best practice" asset management methodology for the asset types for which only age data is available."

QUESTION:

c) Please explain how Manitoba Hydro can implement a best practice asset management methodology using only asset age data?

RATIONALE FOR QUESTION:

RESPONSE:

c) Manitoba Hydro's response to PUB/MH I-98c explained that Marketing and Customer Service will strive to implement a "best practice" asset management methodology for the asset types for which only age data is available. The response did not indicate that this best practice methodology would only use asset age data.

Rather, multiple factors including asset condition, operational history, asset type, environmental conditions and other factors are analyzed when making asset management decisions.

In cases where only age data is available for specific assets Manitoba Hydro is reviewing the data requirements along with the cost of data collection. In some circumstances, assets will be run to failure and replaced only when required. In other circumstances, maintenance decisions will be triggered when the benefit of replacing the asset outweighs the costs of data collection to assess its condition.

Utilization of age limitation for individual asset classes also helps plan for realistic assessments of an asset's serviceable life. Please also refer to PUB/MH II-81d for additional details.

97

REFERENCE:

Tab 5, Page 7 of 28.

PREAMBLE TO IR (IF ANY):

“Manitoba Hydro’s electric system consists of the generation, transmission and distribution assets used to deliver electricity to customers. In general, the status of the system and need for investment can be summarized as follows:

“The highest need for investment is in the distribution system. Aging populations of assets, expansion required to service regional growth and condition and capacity concerns on the existing system are expected to put pressure on long term funding levels.”

QUESTION:

a) Does Manitoba Hydro expect Distribution System capital expenditure levels to increase significantly in future GRA filings?

b) What alternative investment scenarios have been considered by Distribution to determine that the proposed CEF16 plan is optimal?

RATIONALE FOR QUESTION:

RESPONSE:

a) As outlined in Tab 5, the highest need for capital investment is currently in the distribution system. This has been reflected in CEF16 with an allocation of greater than 40% of the cumulative 5 year Business Operations Capital forecast from 2018 to 2022. Capital expenditure levels for the major asset categories (i.e. generation, transmission, distribution, and corporate infrastructure) are reviewed annually. The allocation of target to each major asset category is based on a review of the overall system priorities, considering changes in business, financial and economic assumptions as well as operational risk factors to ensure the spending levels deliver optimal value to the ratepayers of Manitoba. This annual review process will determine the future allocation of spend levels for each major asset category to be filed in future General Rate Applications.

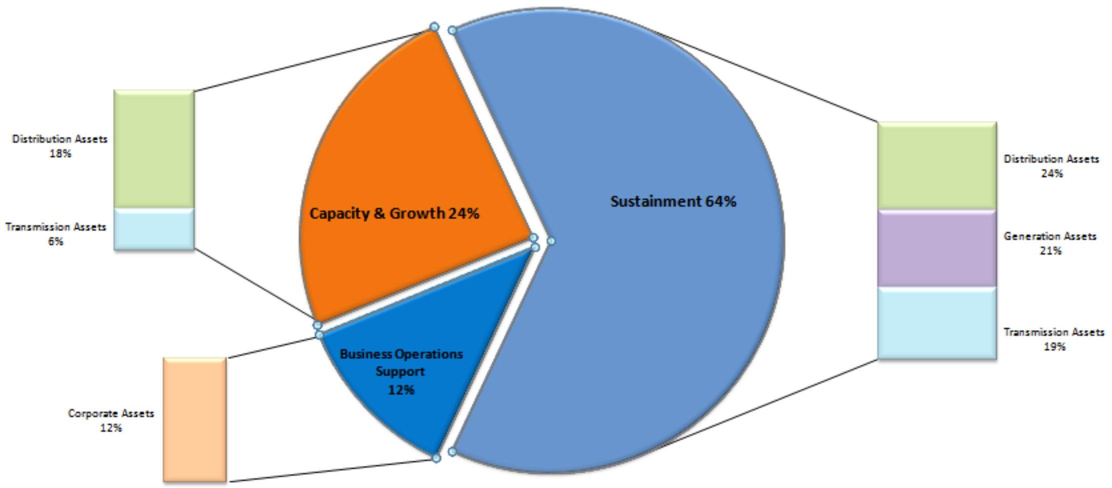
b) Distribution is reviewing the recommendations of the recently received Kinectrics Asset Health Index study in detail to quantify the necessary incremental investments. Copperleaf (C55) will be leveraged as a tool during development of future capital budgets and consideration of any alternatives.

Figure 5.11 Electric Business Operations Capital by Investment Category

($ Millions)	2017 Outlook	2018	2019	2018-2027 10 Year Total
Capacity & Growth				
System Load Capacity	159	144	128	890
Customer Connections - Residential, Commercial & Indus	37	40	43	454
Grid Interconnections - Independent Power Producer	(0)	(0)	(0)	(3)
Total Capacity & Growth- Electric	**195**	**183**	**170**	**1 341**
Sustainment				
System Renewal	225	217	230	3 062
Mandated Compliance	56	39	37	302
System Efficiency	22	23	17	178
Decommissioning	0	0	0	6
Total Sustainment- Electric	**303**	**280**	**284**	**3 549**
Business Operations Support				
Information Technology	25	27	27	263
Fleet	17	15	15	157
Corporate Facilities	25	12	12	138
Tools and Equipment	5	5	5	52
Town site Infrastructure	3	4	1	16
Generation Buildings and Grounds	-	-	1	32
Total Business Operations Support- Electric	**75**	**63**	**62**	**659**
Unallocated Year End Outlook Adjustment -Electric	(45)	-	-	-
Total Unallocated Target Adjustment- Electric	**(45)**	**-**	**-**	**-**
Total Electric Business Operations Capital	**529**	**526**	**517**	**5 549**

Figure 5.12 provides a breakdown by major asset type (i.e. generation, transmission, distribution and corporate assets) within each of the primary investment categories.

Figure 5.12 Electric Business Operations Capital by Investment Category



REFERENCE:

Business Operations Capital and Asset Management Technical Conference Transcript, July 20, 2017, Page 134

PREAMBLE TO IR (IF ANY):

Customer Preferences

QUESTION:

Please provide any documentation of outreach sessions with or surveys of Manitoba Hydro's customers and ratepayers demonstrating, for example, their preferences for tradeoffs between rate increases and improved reliability performance.

RATIONALE FOR QUESTION:

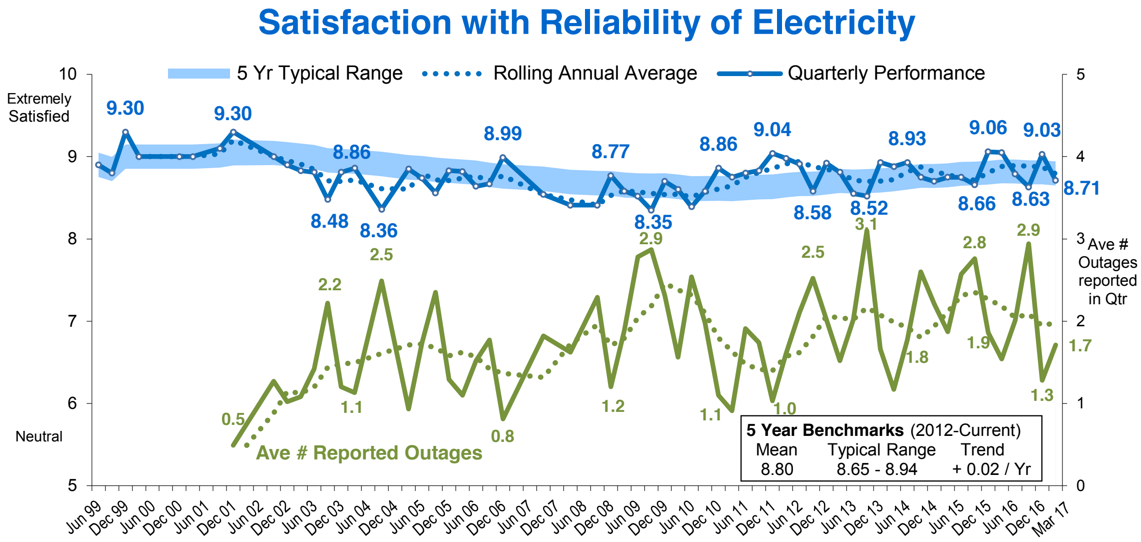
RESPONSE:

Manitoba Hydro has not undertaken research specifically investigating preferences for tradeoff between rate increases and improved reliability performance among its customers.

Manitoba Hydro monitors residential customer satisfaction with all aspects of its service including Reliability of Electricity and Price of Electricity through its Customer Satisfaction Tracking Study (CSTS). Please see Manitoba Hydro's response to Coalition/MH I-17h for a copy of the most recent results up to and including the fourth quarter of the 2016/17 fiscal year.

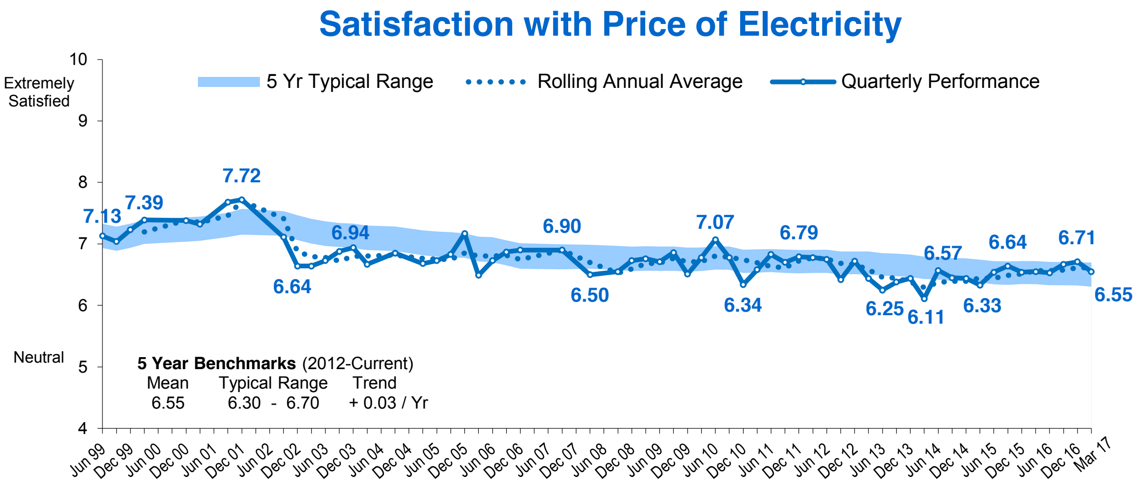
Reliability of Electricity continues to receive high satisfaction scores. Typically 90% or more of respondents report a score of 7 or higher on a 1-10 scale. At the end of the 2016/17 fiscal year, respondents report an average satisfaction score with Manitoba Hydro's Reliability of Electricity of 8.71, as shown below. Manitoban's satisfaction with Reliability of Electricity ranks among the leading electric utilities in Canada based on annual national research done by the Canadian Electric Association.

Figure 1. Satisfaction with Reliability of Electricity (CSTS Survey)



Price of Electricity typically receives satisfaction scores of 7 or higher from 55% of respondents. At the end of the 2016/17 fiscal year, respondents report an average satisfaction score with Manitoba Hydro's Price of Electricity of 6.55, as shown below. Manitoba respondent satisfaction with Price of Electricity also ranks among the leading electric utilities in Canada for similar measures regarding price and value based on annual national research done by the Canadian Electric Association.

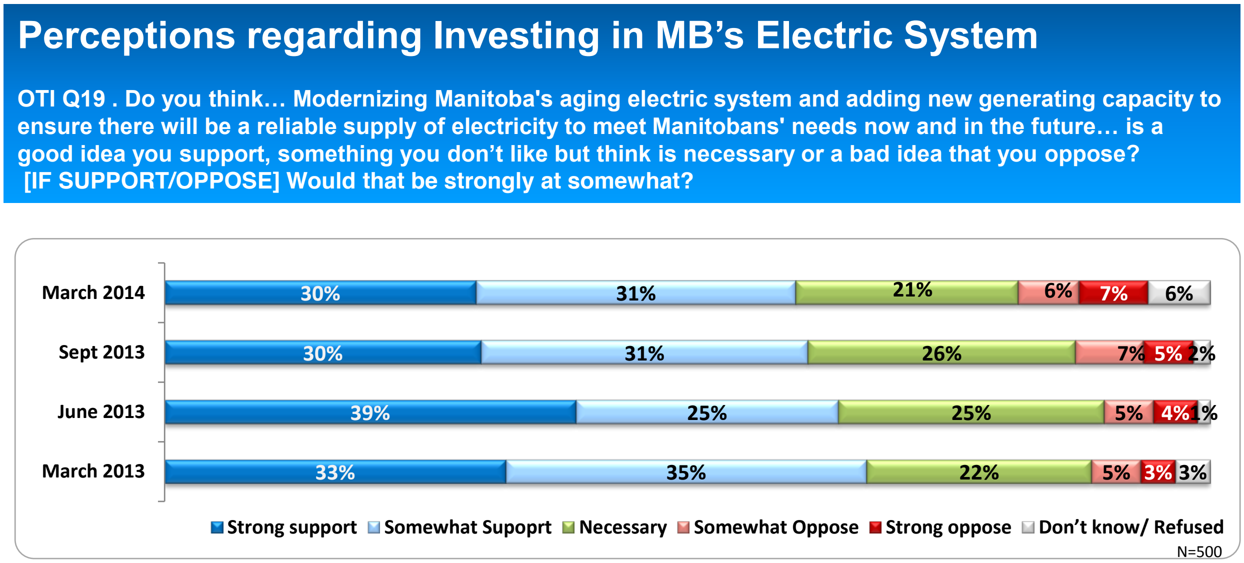
Figure 2. Satisfaction with Price of Electricity (CSTS Survey)



* The CEA Public Attitude Research ceased to include this measure in 2014.

In 2013/14, Manitoba Hydro conducted research regarding Manitoban's perceptions of the need to reinvest in Manitoba's electric infrastructure. Key findings from the March 2014 survey research are illustrated in the Figures below.

Figure 3. Perceptions on Investing in Electric Infrastructure (2014 Survey)

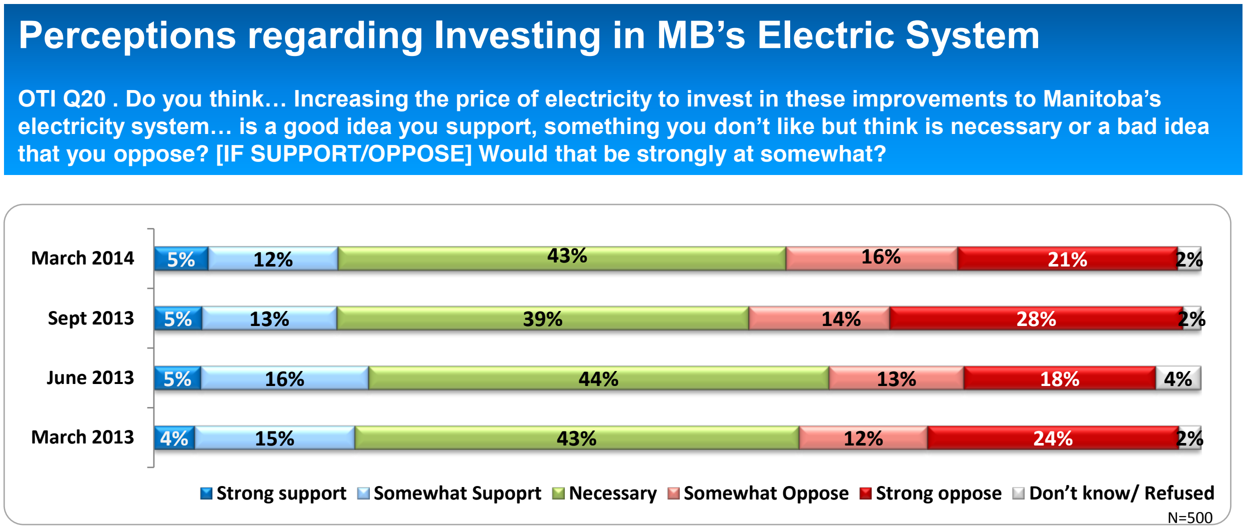


Perceptions regarding Investing in MB's Electric System

OTI Q19 . Do you think… Modernizing Manitoba's aging electric system and adding new generating capacity to ensure there will be a reliable supply of electricity to meet Manitobans' needs now and in the future… is a good idea you support, something you don't like but think is necessary or a bad idea that you oppose?
[IF SUPPORT/OPPOSE] Would that be strongly at somewhat?

Most respondents (82%) supported modernizing Manitoba's aging electric system and adding new generating capacity to ensure there will be a reliable supply of electricity to meet Manitobans' needs now and in the future. This includes 61% who outright ("strongly" or "somewhat") supported this and 21% who "reluctantly" supported this (dislike the idea but believe upgrades are necessary). Only 13% strongly or somewhat opposed this.

Figure 4. Perceptions on Investing in Electric Infrastructure (2014 Survey)

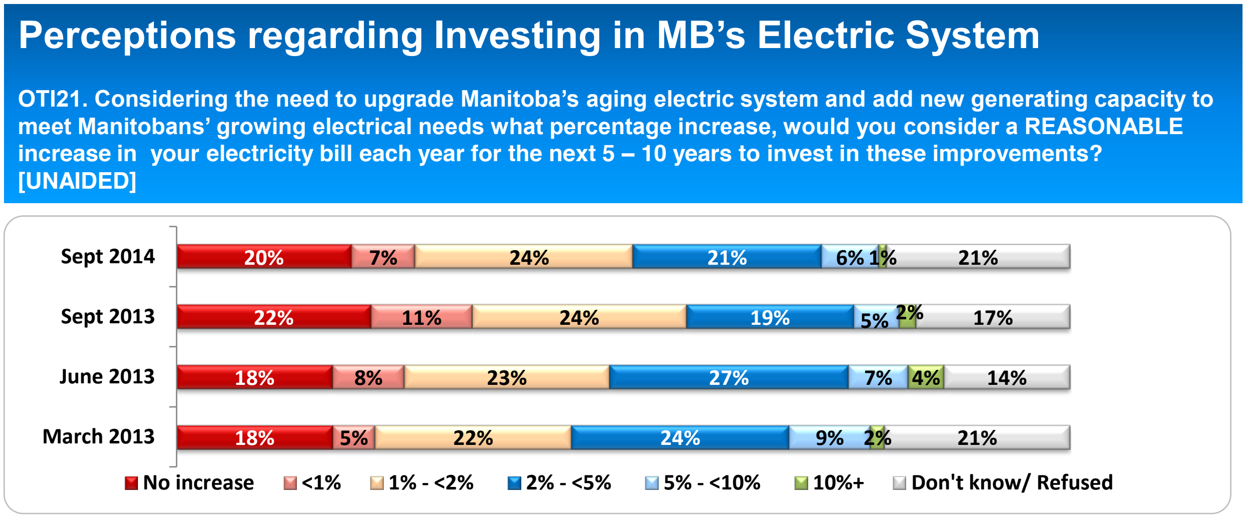


Perceptions regarding Investing in MB's Electric System

OTI Q20 . Do you think… Increasing the price of electricity to invest in these improvements to Manitoba's electricity system… is a good idea you support, something you don't like but think is necessary or a bad idea that you oppose? [IF SUPPORT/OPPOSE] Would that be strongly at somewhat?

The majority of respondents (60%) supported or reluctantly supported increasing the price of electricity to invest in improvements to Manitoba's electricity system. This includes 17% who outright supported a price increase and 43% who reluctantly supported it. A third (37%) of respondents opposed increasing the price of electricity to invest in improvements to Manitoba's electricity system.

Figure 5. Perceptions on Investing in Electric Infrastructure (2014 Survey)

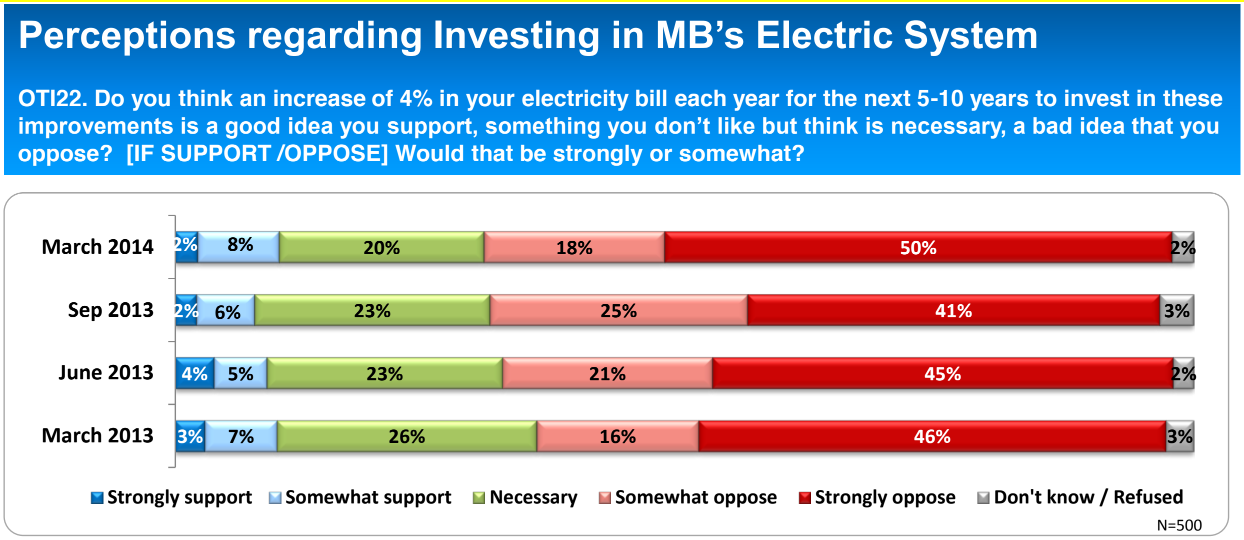


Perceptions regarding Investing in MB's Electric System

OTI21. Considering the need to upgrade Manitoba's aging electric system and add new generating capacity to meet Manitobans' growing electrical needs what percentage increase, would you consider a REASONABLE increase in your electricity bill each year for the next 5 – 10 years to invest in these improvements? [UNAIDED]

Over half of respondents (59%) thought that some level of annual increase in their electricity bill for the next 5-10 years would be reasonable to upgrade Manitoba's aging electric system and add new generation capacity to meet Manitoban's growing electrical needs.

Figure 6. Perceptions on Investing in Electric Infrastructure (2014 Survey)



Perceptions regarding Investing in MB's Electric System

OTI22. Do you think an increase of 4% in your electricity bill each year for the next 5-10 years to invest in these improvements is a good idea you support, something you don't like but think is necessary, a bad idea that you oppose? [IF SUPPORT /OPPOSE] Would that be strongly or somewhat?

A third of respondents (30%) indicated they supported or reluctantly supported an increase of 4% in their electricity bill each year for the next 5-10 years to invest in these improvements to Manitoba's electricity system. This includes 10% who outright supported a 4% annual increase and 30% who reluctantly supported a 4% annual rate increase. 68% of respondents opposed such a rate increase.

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REFERENCE:

Business Operations Capital and Asset Management Technical Conference Transcript, July 20, 2017, Pages 60 - 62

PREAMBLE TO IR (IF ANY):

Pre-emptive asset retirements involve ratepayers losing at least some useful life of the asset that is replaced prior to failure, with the tradeoffs presumably being that the asset won't randomly fail at an inopportune time and the unit cost of replacement will be lower for non-emergency replacements. However, consistent implementation of early replacement of assets within a specific asset class will affect the calculation of Typical Useful Life for that asset class. Over time there is a risk that this process will unduly shorten the calculated Typical Useful Life for all asset classes subject to pre-emptive replacements.

QUESTION:

How does Manitoba Hydro intend to avoid skewing its Typical Useful Life values for those asset classes that are pre-emptively retired?

RATIONALE FOR QUESTION:

RESPONSE:

Assets are removed due to non-condition based reasons, such as capacity upgrades, voltage conversion, road relocations, etc. and for condition based reasons that include failures and pre-emptive replacement at the end of life before failure occurred. In the latter case, assets that are replaced are at or close to the end of life, and therefore there is relatively little useful life left.

Any shortening of the Typical Useful Life based on removal statistics is mostly due to non-condition driven replacements. Typical Useful Life is not used as an asset replacement criterion at Manitoba Hydro and therefore the actual useful life of the asset is not impacted by any potential skewing of the typical useful life.

For example, a decision to replace a wood pole due to condition will be made based on its assessed above ground condition and/or specific below ground testing conducted as part of the Integrated Pole Maintenance Program to assess pole strength. The age of the pole is not a determining factor.

REFERENCE:

PUB MFR 92 Attachment 1 – Manitoba Hydro 2016 Asset Condition Assessment by Kinectrics – Section III – Results, Page 17 of 260; PUB/MH I-103a-c

PREAMBLE TO IR (IF ANY):

In its response to PUB/MH I-103 (a), Manitoba Hydro states: “Functional Failures correspond to events where the unit ceased to perform a required function but had not tripped.”

In its response to PUB/MH I-103 (b), Manitoba Hydro states: “Manitoba Hydro’s approach is to replace wood poles proactively i.e. before they fail, so the forecasted numbers is a combination of poles to be replaced proactively based on testing and inspection results (no failures) and expected failures estimated by applying degradation curves to the age distribution. An average pole lifespan value is not measured.”

QUESTION:

a) Please provide examples of Functional Failures, and explain how they are tracked.

b) Please describe how the typical useful life values utilized in the Kinectrics analysis are determined.

RATIONALE FOR QUESTION:

RESPONSE:

a) Functional Failures are issues that force a breaker to be removed from service but not from automatic fault clearing. Examples include a severe leak of insulating medium or visual indication of significant damage to the asset that could lead to an impending failure.

Manitoba Hydro tracks these failures using a computerized maintenance management system.

b) Typical useful life values were derived based on Manitoba Hydro's historical wood pole removal records. The records, which included pole installation and removal dates were used to determine Kinectrics' removal model (with the assumption of Weibull distribution). The mathematical curve fitting based on such approach yields a cluster of curves as follows: removal density curve, annual removal curve, and cumulative probability of failure curve.

REFERENCE:

PUB MFR 92 Attachment 3 – Asset Condition Assessment Methodology Standards & Results Update (2017) – Asset Condition Assessment Scoring & Replacement Requirements, Page 6 of 10; PUB/MH I-110a-f

PREAMBLE TO IR (IF ANY):

In its response to PUB/MH I-110 (b), Manitoba Hydro states: "Manitoba Hydro does not currently use the percentage of remaining service life as a parameter in the management of its assets and has not attempted to correlate the ACA score with the percentage of remaining service life. Manitoba Hydro uses ACA scores to provide a good indication of the relative priority of assets that require attention within an asset class and can be used for longer-term planning as an indicator of potential investment requirements."

QUESTION:

a) Please confirm whether Manitoba Hydro’s response to PUB/MH I-110 (b) should be interpreted to mean that mitigation projects addressing the least healthy assets continue until the budget is fully consumed, rather than addressing asset condition issues until the risk exposure to the system and ratepayers is reduced to an acceptable level.

b) If not confirmed, please explain in detail what safeguards are in place to ensure that asset condition mitigation does not continue after the risk exposure to the system and ratepayers has been reduced to an acceptable level, even if there is remaining headroom in the budget.

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) and b):

Not confirmed. PUB/MH I-110b states that Manitoba Hydro uses Asset Condition Assessment (ACA) scores to determine the number of assets within individual asset classes that are in various conditions ranging from good to very poor condition. Assets that are in very poor condition are prioritized for replacement through mitigation programs in order to reduce the risk exposure to the system and rate payers. With existing mitigation programs subject matter experts and line management determine replacement plans each year based on the condition of specific asset classes and associated risk levels. The budgets are calibrated to reduce risk to an acceptable level rather than simply replace as many assets as possible. For specific asset classes such as wood poles and underground cables, it is not possible to replace all assets that are in very poor condition. Therefore, mitigation program budgets are being fully consumed based on risk reduction and do not yield results that reduce risk to lower than acceptable levels.

99

REFERENCE:

PUB MFR 8; PUB/MH I-88a-b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Based on Manitoba Hydro's response to PUB/MH I-88 (a), what drove the high SAIDI values in 2012, 2015 and 2016?

b) Based on Manitoba Hydro's response to PUB/MH I-88 (b), what drove the high SAIDI value (excluding major weather events) in year 2015?

c) Based on Manitoba Hydro's response to PUB/MH I-88 (b), what drove the high SAIDI values (excluding Transmission outages) in years 2015 and 2016?

RATIONALE FOR QUESTION:

RESPONSE:

a) Major events contributed over 50, 41 and 47 minutes to SAIDI in 2012, 2015 and 2016 respectively. A summary of the major events is shown below:

<u>2012</u>

June:

- On June 27 a storm went through the western part of the province causing multiple outages totaling 3,756,311 Customer Minutes or 6.92 to the total SAIDI.

July:

- On July 29 a storm went through the Interlake region of the province causing multiple outages totaling 6,267,813 Customer Minutes or 11.54 to the total SAIDI.

August:

- On August 9 East Selkirk station had an outage which damaged both banks and a mobile sub was required to be installed to restore service. This outage accounts for 1,881,400 Customer Minutes or 3.47 minutes to the total SAIDI.
- On August 15 an outage occurred on 66 kV line 48 due to broken cross-arms. This outage accounts for 1,798,221 Customer Minutes or 3.31 minutes to the total SAIDI.

October:

- On October 4-5 an ice storm hit the eastern part of the province causing multiple outages totaling 10,124,390 Customer Minutes or 18.62 minutes to the total SAIDI.
- On October 24 an outage during blizzard conditions on 138 kV line KH38, an air patrol was unable to fly that day due to the weather conditions, no fault was found the following day. This outage accounts for 3,783,759 Customer Minutes or 6.96 minutes to the total SAIDI.

2015

January:

- On January 28 an outage occurred on 24 kV lines L17 and L18 due to a pole fire. This outage contributed 2,668,700 customer minutes or 4.77 minutes to the total SAIDI.

March:

- On March 6 McPhillips 24 kV Lines L17 and L18 were forced out of service due to a pole fire on a common structure. This outage contributed 2,007,775 customer minutes or 3.59 minutes to the total SAIDI.
- On March 24-25 heavy snow and high winds throughout the province caused multiple outages totaling 5,550,220 customer minutes or 9.91 minutes to the total SAIDI.

May:

- On May 17 - 18 high winds and stormy weather hit the province causing multiple outages. These outages contributed 9,222,487 customer minutes or 16.45 minutes to the total SAIDI.

July:

- On July 26 Mystery Lake 138 kV line WL43 tripped during storm conditions due to damaged insulators and conductor. The outage lasted 28 hours and affected 1,159 customers resulting in 1,955,233 customer minutes or 3.48 minutes to the total SAIDI.

October:

- On October 12 high wind conditions in Berens River area prevented an air patrol of 66kV line 60 after it locked out. This outage contributed 1,958,765 customer minutes or 3.48 minutes to the total SAIDI.

2016

June:

- On June 19 high winds and stormy weather hit the province causing multiple outages. These outages contributed 3,095,746 Customer Minutes or 5.47 minutes to the total SAIDI.
- On June 26 high winds and stormy weather hit the province causing multiple outages. These outages contributed 3,434,090 Customer Minutes or 6.07 minutes to the total SAIDI.

July:

- On July 20 a severe weather system tracked across the southern part of the province severely impacting Portage La Prairie (Tornado – Long Plains First Nation), then hitting Winnipeg, Selkirk, and Lac Du Bonnet. These outages contributed 12,923,920 Customer Minutes or 22.79 minutes to the total SAIDI.

August:

- On August 3-4 high winds and stormy weather hit the Morden area causing multiple outages. These outages contributed 4,929,441 Customer Minutes or 8.69 minutes to the total SAIDI.

December:

- On December 26 high winds and stormy weather hit the Winnipeg area causing multiple outages. These outages contributed 2,627,391 Customer Minutes or 4.61 minutes to the total SAIDI.

b) Major events contributed over 15 minutes to SAIDI (excluding major weather events) in 2015. A summary of the major events is shown below:

January 2015:

- On January 28 an outage occurred on 24 kV lines L17 and L18 in Keewatin CSC due to a pole fire. This outage contributed 2,668,700 customer minutes or 4.77 minutes to the total SAIDI.

March 2015:

- On March 6 McPhillips 24 kV Lines L17 and L18 were forced out of service due to a pole fire on a common structure. This outage contributed 2,007,775 customer minutes or 3.59 minutes to the total SAIDI.

July 2015:

- On July 26 Mystery Lake 138kV line WL43 tripped during storm conditions due to damaged insulators and conductor. The outage lasted 28 hours and affected 1,159 customers resulting in 1,955,233 customer minutes or 3.48 minutes to the total SAIDI.

October 2015:

- On October 12 high wind conditions in Berens River area prevented an air patrol of 66 kV line 60 after it locked out. This outage contributed 1,958,765 customer minutes or 3.48 minutes to the total SAIDI.

c) Major events contributed over 38 and 47 minutes to SAIDI in 2015 and 2016, respectively (excluding Transmission outages). A summary of the major events is shown below:

<u>2015</u>

January:

- On January 28 an outage occurred on 24kV lines L17 and L18 due to a pole fire. This outage contributed 2,668,700 customer minutes or 4.77 minutes to the total SAIDI.

March:

- On March 6 McPhillips 24 kV Lines L17 and L18 were forced out of service due to a pole fire on a common structure. This outage contributed 2,007,775 customer minutes or 3.59 minutes to the total SAIDI.

October:

- On October 12 high wind conditions in Berens River area prevented an air patrol of 66kV line 60 after it locked out. This outage contributed 1,958,765 customer minutes or 3.48 minutes to the total SAIDI.

2016

June:

- On June 19 high winds and stormy weather hit the province causing multiple outages. These outages contributed 3,095,746 Customer Minutes or 5.47 minutes to the total SAIDI.
- On June 26 high winds and stormy weather hit the province causing multiple outages. These outages contributed 3,434,090 Customer Minutes or 6.07 minutes to the total SAIDI.

July:

- On July 20 a severe weather system tracked across the southern part of the province severely impacting Portage La Prairie (Tornado – Long Plains First Nation), then hitting Winnipeg, Selkirk, and Lac Du Bonnet. These outages contributed 12,923,920 Customer Minutes or 22.79 minutes to the total SAIDI.

August:

- On August 3-4 high winds and stormy weather hit the Morden area causing multiple outages. These outages contributed 4,929,441 Customer Minutes or 8.69 minutes to the total SAIDI.

December:

- On December 26 high winds and stormy weather hit the Winnipeg area causing multiple outages. These outages contributed 2,627,391 Customer Minutes or 4.61 minutes to the total SAIDI.

REFERENCE:

PUB MFR 92 Attachment 1 – Manitoba Hydro 2016 Asset Condition Assessment by Kinectrics – Section III – Results, Page 18 of 260; and Section V – Appendix A: Results for Each Asset Category, Page 30 of 260; PUB/MH I-104a-e

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB/MH I-104 (a)

"There is a need to strike a balance between reducing a backlog of units flagged for replacement based on the results of the Asset Condition Assessment and the associated capital costs, especially since there will be additional non-condition driven replacements. A prudent strategy is to eliminate the backlog over a certain period of time, usually 3 to 5 years."

Reference: Manitoba Hydro Response to PUB/MH I-104 (b)

"The ultimate decision on the pacing of investments is based on the results of the 2016 Asset Condition Assessment by Kinectrics (filed as Attachment 1 to PUB MFR 92), estimate of non-condition based replacements, financial constraints and corporate risk tolerance related to reliability, customer service, brand name impairment, etc.

Finally, there are many factors that impact reliability performance, such as weather induced stresses, electrical faults, and external causes (e.g. wildlife and vehicle collisions)."

Reference: Manitoba Hydro Response to PUB/MH I-104 (c)

"Without the use of an Age Limiting Factor, replacement needs would be understated as units may appear to be in a better condition than they are based on their age and established degradation curves."

Reference: Manitoba Hydro Response to PUB/MH I-104 (d)

"Use of an Age Limiting Factor allows for a better prediction of the number of units that are expected to fail over the next several years and is useful for identifying units or percentage of assets that need to be addressed regardless of whether they are replaced proactively or reactively."

Reference: Manitoba Hydro Response to PUB/MH I-104 (e)

"The requested information was not part of the Asset Health Index study undertaken by Kinectrics and is not available."

QUESTION:

a) In the response to PUB/MH I-104 (a), Manitoba Hydro states that "a prudent strategy is to eliminate the backlog over a certain period of time, usually 3 to 5 years." What is the analytic basis for selecting the "3 to 5 year" period?

b) Please provide examples of values associated with the following parameters: financial constraints and corporate risk tolerance related to reliability, customer service, and brand name impairment.
   i. Please provide a justification for the inclusion of 'brand name impairment' as a criterion impacting the pacing of investment decisions.

c) Please quantify the impact on reliability performance by each of the individual factors identified in following statement: "Finally, there are many factors that impact reliability performance, such as weather induced stresses, electrical faults, and external causes (e.g. wildlife and vehicle collisions)."

d) In accordance with Manitoba Hydro Response to PUB/MH I-104 (c), why would age be a useful parameter to consider if asset condition had been professionally tested and evaluated separately?

e) In accordance with Manitoba Hydro Response to PUB/MH I-104 (d), please explain why Manitoba Hydro considers age to be a better indicator than condition assessment?

f) Please confirm if Manitoba Hydro's response to PUB/MH I-104 (e) indicates that the age limiting factor was not used to identify any asset replacements.

g) What is the process that Manitoba Hydro uses to re-calibrate the Age Limiting Factor curves for an asset when actual failure rates and actual asset lifespans (after excluding items such as weather events, externally caused failures such as cars hitting poles etc.) are different than the expected curves?

   i. Please provide an example of such a recalibration showing the original and revised Age Limiting Factor curve.

   ii. If Manitoba Hydro is not performing recalibrations of its Age Limiting Curves, how does Manitoba Hydro ensure they are not overstating Flagged For Action items.

RATIONALE FOR QUESTION:

RESPONSE:

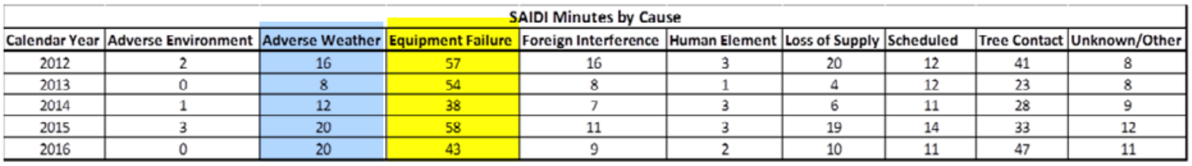
a) There is no analytic basis for this timeframe. From Kinectrics' experience, a 3 to 5 years' timeframe strikes a balance between addressing the backlog while managing costs.

b) Marketing & Customer Service has just begun evaluating new investment proposals applying the Corporate Value Framework evaluation tool; therefore, specific examples are not available at this time.

   PUB MFR 107-Attachment-1 describes in detail each of the three value measures noted in this question; Distribution Reliability is found on pages 33-34, Customer Service on page 40 and Public Perception (i.e. brand name impairment) on page 39. It is possible that an investment proposal for asset replacement such as a distribution line refurbishment project may impact all three value measures referenced in the question.

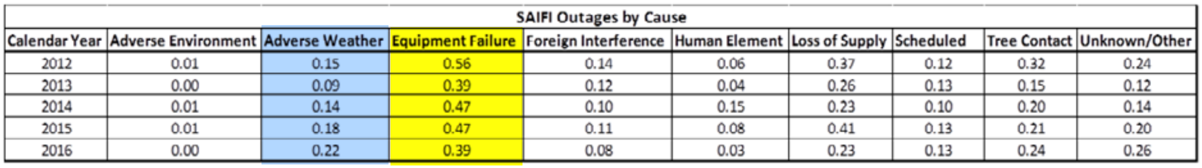
   i. 'Brand name impairment' is included as a criterion impacting the pacing of investment decisions to capture investments which if deferred could cause the organization's customers or other external stakeholders to lose confidence in the organization (see Public Perception Risk, page 39) .

c) Tables of the reliability impacts for the past five years by cause is provided below. Outages as a result of wildlife and vehicle interference fall under the Foreign Interference category.



SAIDI Minutes by Cause

Calendar Year	Adverse Environment	Adverse Weather	Equipment Failure	Foreign Interference	Human Element	Loss of Supply	Scheduled	Tree Contact	Unknown/Other
2012	2	16	57	16	3	20	12	41	8
2013	0	8	54	8	1	4	12	23	8
2014	1	12	38	7	3	6	11	28	9
2015	3	20	58	11	3	19	14	33	12
2016	0	20	43	9	2	10	11	47	11



SAIFI Outages by Cause

Calendar Year	Adverse Environment	Adverse Weather	Equipment Failure	Foreign Interference	Human Element	Loss of Supply	Scheduled	Tree Contact	Unknown/Other
2012	0.01	0.15	0.56	0.14	0.06	0.37	0.12	0.32	0.24
2013	0.00	0.09	0.39	0.12	0.04	0.26	0.13	0.15	0.12
2014	0.01	0.14	0.47	0.10	0.15	0.23	0.10	0.20	0.14
2015	0.01	0.18	0.47	0.11	0.08	0.41	0.13	0.21	0.20
2016	0.00	0.22	0.39	0.08	0.03	0.23	0.13	0.24	0.26

d) Assets of a certain age, notwithstanding test results and evaluation regarding its condition, cannot be expected to last indefinitely. Even if test results show it to be in good condition, the presence of degradation aspects not detected by the testing will limit its useful life. An age limitation helps plan for a realistic assessment of an asset's serviceable life. Further discussion of the age limiting factor can be found in the response to PUB/MH I-107.

e) Manitoba Hydro does not consider age to be a better indicator than condition assessment. Age limiting factor is used in conjunction with calculated condition to better predict the number of units expected to fail over the next several years. Age Limiting Factor is used as a condition score ONLY if calculated condition exceeds it.

f) The requested information was not readily available at that time, but has now been obtained from Kinectrics. The question asked how many assets in the following classes were planned for replacement due to the Age Limiting Factor. At the time of response no information was available, however upon further examination of the data, Kinectrics was able to provide the following breakdown. However, please note the flagged for action list detailed below does not necessarily mean each assets will be replaced on an age basis. For each asset, individual replacements will continue to be driven by specific condition-based assessments and age data issued as a budgetary tool.

i. Wood Poles – 90,395 Poles out of 1,053,178 poles were flagged for action based on the age limiting factor.
ii. Station Breakers – 22 Breakers out of 1,355 units were flagged for action based on the age limiting factor.
iii. Manholes – 1,266 out of 2,179 units were flagged for action based on the age limiting factor.

g) Manitoba Hydro does not currently have a process for re-calibrating the age limiting factor curves. Kinectrics was hired to calculate the original curves and Manitoba Hydro is in the process of starting to capture pole salvage reasons as part of its work order process. Once a significant number of poles have been captured with the salvage reason, Manitoba Hydro will re-calibrate the age limiting factor curves.

i. The requested recalibration of the data is not available. The ability to capture the additional information (i.e. pole salvage reason) does not currently exist, but is in development.
ii. Without the use of Age Limiting Factor replacement, needs would be understated due to the units that appear to be in a better condition than they possibly could be based on their age and established degradation curves. The degradation curves used in the study were based on experience of Manitoba Hydro staff, available removal statistics and industry data which represent the best available information at this point in time.

100

REFERENCE:

PUB MFR 93 – Capital Expenditures, Page 2 of 6; PUB/MH I-80a-b

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB/MH I-80a-b-Attachment, Page 4 of 9

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	5.05%	For current corporate rates see G911

Reference: Manitoba Hydro Response to PUB/MH I-122a-Attachments, Page 4 of 18

ANALYSIS OF ALTERNATIVES:

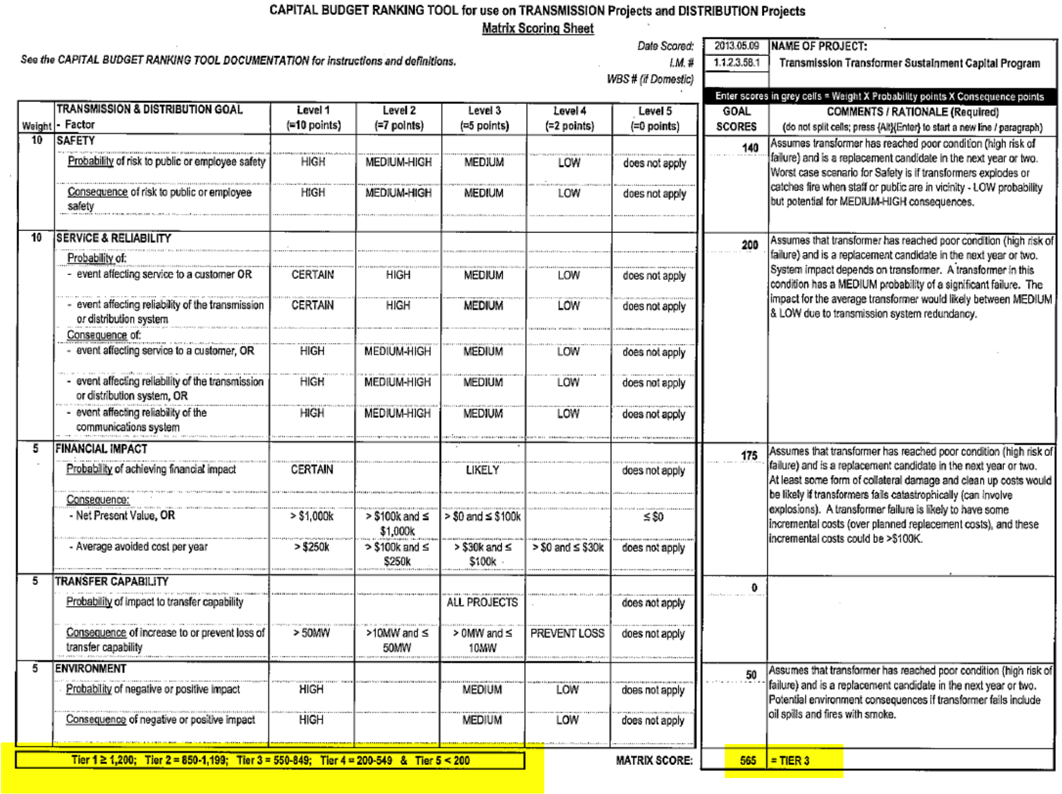
ECONOMIC ANALYSIS		
Discount Rate	For current corporate rates see P911 **4.4%**	

Reference: Manitoba Hydro Response to PUB/MH I-122a-Attachments, Page 14 of 18

ANALYSIS OF ALTERNATIVES:

ECONOMIC ANALYSIS		
Discount Rate	For current corporate rates see P911 **4.15%**	Real Discount Rate%

Reference: Manitoba Hydro Response to PUB/MH I-80a-b-Attachment, Page 7 of 9



CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects and DISTRIBUTION Projects

Matrix Scoring Sheet

See the CAPITAL BUDGET RANKING TOOL DOCUMENTATION for instructions and definitions.

Date Scored: 2013.05.09
I.M. # 1.1.2.3.58.1
WBS # (if Domestic)

NAME OF PROJECT: Transmission Transformer Sustainment Capital Program

Enter scores in grey cells = Weight X Probability points X Consequence points

Weight	TRANSMISSION & DISTRIBUTION GOAL - Factor	Level 1 (=10 points)	Level 2 (=7 points)	Level 3 (=5 points)	Level 4 (=2 points)	Level 5 (=0 points)	GOAL SCORES	COMMENTS / RATIONALE (Required) (do not split cells; press {Alt}{Enter} to start a new line / paragraph)
10	SAFETY						140	Assumes transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. Worst case scenario for Safety is if transformers explodes or catches fire when staff or public are in vicinity - LOW probability but potential for MEDIUM-HIGH consequences.
	Probability of risk to public or employee safety	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	Consequence of risk to public or employee safety	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
10	SERVICE & RELIABILITY						200	Assumes that transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. System impact depends on transformer. A transformer in this condition has a MEDIUM probability of a significant failure. The impact for the average transformer would likely between MEDIUM & LOW due to transmission system redundancy.
	Probability of:							
	- event affecting service to a customer OR	CERTAIN	HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the transmission or distribution system	CERTAIN	HIGH	MEDIUM	LOW	does not apply		
	Consequence of:							
	- event affecting service to a customer, OR	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the transmission or distribution system, OR	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the communications system	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
5	FINANCIAL IMPACT						175	Assumes that transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. At least some form of collateral damage and clean up costs would be likely if transformers fails catastrophically (can involve explosions). A transformer failure is likely to have some incremental costs (over planned replacement costs), and these incremental costs could be >$100K.
	Probability of achieving financial impact	CERTAIN		LIKELY		does not apply		
	Consequence:							
	- Net Present Value, OR	> $1,000k	> $100k and ≤ $1,000k	> $0 and ≤ $100k		≤ $0		
	- Average avoided cost per year	> $250k	> $100k and ≤ $250k	> $30k and ≤ $100k	> $0 and ≤ $30k	does not apply		
5	TRANSFER CAPABILITY						0	
	Probability of impact to transfer capability			ALL PROJECTS		does not apply		
	Consequence of increase to or prevent loss of transfer capability	> 50MW	>10MW and ≤ 50MW	> 0MW and ≤ 10MW	PREVENT LOSS	does not apply		
5	ENVIRONMENT						50	Assumes that transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. Potential environment consequences if transformer fails include oil spills and fires with smoke.
	Probability of negative or positive impact	HIGH		MEDIUM	LOW	does not apply		
	Consequence of negative or positive impact	HIGH		MEDIUM	LOW	does not apply		

Tier 1 ≥ 1,200; Tier 2 = 850-1,199; Tier 3 = 550-849; Tier 4 = 200-549 & Tier 5 < 200

MATRIX SCORE: 565 = TIER 3

QUESTION:

d) When calculating the Financial Impact of risk at a discount rate of 5.05%, please explain how the Level 1, Level 2, Level 3, and Level 4 consequences are equivalent for Net Present Value and Average Avoided Cost Per Year respectively (e.g. for Level 1 please explain why an NPV of >$1000k is an equivalent financial impact to an Average Avoided cost per year of >$250k/year).

e) Given that the Financial Impacts of risks are not equivalent for NPV versus Average Avoided Cost per Year, please explain how the optimization of capital replacement versus operating costs is justified.

f) Please provide the quantitative definition of High, Medium-High, Medium, Low, and "does not apply" for Consequence.

g) Please provide the quantitative definition of Certain, High, Medium-High, Medium, Low, and "does not apply" for Probability.

h) How are the weightings for the different risk categories set, and what causes them to change from project to project?

i) What is the definition of acceptability of Tier 1, Tier 2, Tier 3, Tier 4 and Tier 5 risk, and what steps are required to accept each of these risks?

j) Why doesn't the Capital Project Justification show the risk before and after the Project is completed, and calculate the change in risk associated with the project?

k) Manitoba Hydro’s response to PUB/MH I-80 (b) states that “Approximately 21 transformers will be replaced in the future under this program, beginning in fiscal year 2020/21.” This program is scheduled to run until 2033, yet it is described as a 20-year program with approximately one transformer being replaced each year. Please reconcile these claims.

RATIONALE FOR QUESTION:

RESPONSE:

d) The correlation of "Net Present Value" levels with "Average Avoided Cost per Year" levels within the Capital Budget Ranking Tool was established by calculating the present value for various "Average Avoided Cost per Year" levels and calibrating the results to the "Net Present Value" levels. As an example, a 5-year projection of an "Average Avoided Cost per Year" of $250,000 would yield a present value > $1,000,000 using a discount rate of 5.05%.

e) As stated in the Capital Project Justification, a detailed end-of life assessment will be completed prior to proceeding with any transformer replacement, and this assessment will consider the cost of replacement versus refurbishment versus ongoing maintenance.

f) Please see the Capital Budget Ranking Tool Matrix Application and Definitions included as Attachment 1 to this response.

g) Please see the Capital Budget Ranking Tool Matrix Application and Definitions included as Attachment 1 to this response.

h) The weightings do not change from project to project and were set by Transmission Management. Weightings must provide sufficient separation of overall scores so that projects which score at Level 1 for a particular goal or across more than one goal will clearly rank higher than those that do not. A project's matrix score is not meant to be regarded as an absolute representation of the project's value but rather the relative ranking in terms of importance measured against business goals.

i) There is no correlation between a project's Tier and a particular risk level. The Tiers are a convenient way to group together projects that scored within a similar range. Tier 1 projects should be funded first, followed by Tier 2 projects, and so on. All projects evaluated using the Capital Budget Ranking Tool were justified and approved using the Capital Project Justification process.

j) The Capital Budget Ranking Tool was not designed to measure residual risk but rather the degree to which a particular project will contribute to Transmission goals as identified in the business plan.

k) The program recommendation, written in 2013, anticipated 21 transmission system transformers would need to be replaced over the next 20 years and further anticipated that the first replacement would not be needed for several years. The final in-service date is projected to be in September 2032, which falls in fiscal 2032/33.

REFERENCE:

PUB MFR 93 – Capital Expenditures, Page 2 of 6.

PREAMBLE TO IR (IF ANY):

"Transformers are replaced as they reach economic end of life, based on health index scores and risks assessments. Asset health index scores are updated annually and the need for replacement re-assessed in consideration of risks to the transmission system and to inform refurbishment versus replacement decisions."

QUESTION:

a) Please explain how Manitoba Hydro utilizes risk and cost of replacement to inform transformer refurbishment versus replacement decisions.

b) Please describe the underlying calculations and assumptions used in these decisions, including actual examples for both refurbishment and replacement decisions.

RATIONALE FOR QUESTION:

RESPONSE:

a) Health index scores correlate with the risk of failure and with the remaining useful life of the asset. The decision to replace a transformer depends on the risk of failure of the transformer and on the risks to the transmission system, such as single point of failure and loading at the location on the transmission system. Under the Transmission Transformer Sustainment Capital Program, transformers with lower health index scores and higher risk to the transmission system are prioritized for replacement, with replacements beginning in fiscal year 2020/21.

b) The Transmission Transformer Sustainment Capital Program funds transformer replacements based on prioritization by health index scores, risk assessments and end-of-life assessments by specialists at Manitoba Hydro. Approximately 21 transformers will be replaced in the future under this program, beginning in fiscal year 2020/21.

Since this program will begin to replace transformers in the future, actual examples do not exist at this time.

Please see the Attachment to this response which provides the Capital Project Justification for the Transmission Transformer Sustainment Capital Program.

D1876(A)

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1451.05
DATE: 2013 07 30
Financial Planning

CAPITAL PROJECT JUSTIFICATION
FOR

Transmission Transformer Sustainment Capital Program

REVIEWED BY:
(Greg Parent,
Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: A. Hailey June 19, 2013

Constructing Division:

Designing Division:

Financial: 2013.05.31

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: L. Wittmeier 2013-06-19

Business Unit V.P.: G Nefeld / T.E. Tymofichuk 2013-06-20

BUDGET $: (Total Net Cost)	$66,957,000
START DATE: (1st Cost Flow)	2019 04
IN-SERVICE DATE: (Indicate "Mult" if more than 1)	Mult – 2032 09
RISK MATRIX/ BUSINESS CASE TIER:	Tier 3 (565 points)
INVESTMENT REASONS:	Aging Infrastructure (100%)

OWNING DIVISION: Apparatus Maintenance

I.M. NODE NUMBER: 1.1.2.3.58.1

W.B.S. NUMBERS: P:21575

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Brent Jorowski (Sponsor)
Leanne Bray (Project Manager) LB 13May

DATE PREPARED: 2013 03 06

REPORT NUMBER: TAS 2013/02

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

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

NERC COMPLIANCE * ☐ **YES** ☒ **NO**

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

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects and DISTRIBUTION Projects

Matrix Scoring Sheet

See the CAPITAL BUDGET RANKING TOOL DOCUMENTATION for instructions and definitions.

Date Scored: 2013.05.09
I.M. # 1.1.2.3.58.1
WBS # (if Domestic)

NAME OF PROJECT:
Transmission Transformer Sustainment Capital Program

Enter scores in grey cells = Weight X Probability points X Consequence points

Weight	TRANSMISSION & DISTRIBUTION GOAL - Factor	Level 1 (=10 points)	Level 2 (=7 points)	Level 3 (=5 points)	Level 4 (=2 points)	Level 5 (=0 points)	GOAL SCORES	COMMENTS / RATIONALE (Required) (do not split cells; press {Alt}{Enter} to start a new line / paragraph)
10	**SAFETY**						140	Assumes transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. Worst case scenario for Safety is if transformers explodes or catches fire when staff or public are in vicinity - LOW probability but potential for MEDIUM-HIGH consequences.
	Probability of risk to public or employee safety	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	Consequence of risk to public or employee safety	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
10	**SERVICE & RELIABILITY**						200	Assumes that transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. System impact depends on transformer. A transformer in this condition has a MEDIUM probability of a significant failure. The impact for the average transformer would likely between MEDIUM & LOW due to transmission system redundancy.
	Probability of:							
	- event affecting service to a customer **OR**	CERTAIN	HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the transmission or distribution system	CERTAIN	HIGH	MEDIUM	LOW	does not apply		
	Consequence of:							
	- event affecting service to a customer, **OR**	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the transmission or distribution system, **OR**	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the communications system	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
5	**FINANCIAL IMPACT**						175	Assumes that transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. At least some form of collateral damage and clean up costs would be likely if transformers fails catastrophically (can involve explosions). A transformer failure is likely to have some incremental costs (over planned replacement costs), and these incremental costs could be >$100K.
	Probability of achieving financial impact	CERTAIN		LIKELY		does not apply		
	Consequence:							
	- Net Present Value, **OR**	> $1,000k	> $100k and ≤ $1,000k	> $0 and ≤ $100k		≤ $0		
	- Average avoided cost per year	> $250k	> $100k and ≤ $250k	> $30k and ≤ $100k	> $0 and ≤ $30k	does not apply		
5	**TRANSFER CAPABILITY**						0	
	Probability of impact to transfer capability			ALL PROJECTS		does not apply		
	Consequence of increase to or prevent loss of transfer capability	> 50MW	>10MW and ≤ 50MW	> 0MW and ≤ 10MW	PREVENT LOSS	does not apply		
5	**ENVIRONMENT**						50	Assumes that transformer has reached poor condition (high risk of failure) and is a replacement candidate in the next year or two. Potential environment consequences if transformer fails include oil spills and fires with smoke.
	Probability of negative or positive impact	HIGH		MEDIUM	LOW	does not apply		
	Consequence of negative or positive impact	HIGH		MEDIUM	LOW	does not apply		
	Tier 1 ≥ 1,200; Tier 2 = 850-1,199; Tier 3 = 550-849; Tier 4 = 200-549 & Tier 5 < 200					**MATRIX SCORE:**	565	= TIER 3

Template Revision Date: 2008 07 31

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects
Purpose and Instructions

PURPOSE:

This tool is to be used to rank Transmission capital projects (excluding blankets) using common criteria. The rankings will assist management in making decisions for allocating capital dollars and resources. The tool will NOT be used to review or re-evaluate the technical merits of, or justification for, a project.

Each capital project is to be assigned a Tier ranking by the Project Owner when the CPJ or CER is first going forward for approval. The Tier ranking may subsequently be re-evaluated if and when:

- The Project Owner requests a re-evaluation due to a change that might impact the Goal scores, or
- Transmission senior management revise the Business Unit Goals, or
- The CPJ Business Review Committee revise the Factor Weights, or
- The CPJ Business Review Committee requests a review of the score or decides to over-ride the Tier.

INSTRUCTIONS:

1. Evaluate the project against each of the Goals defined on pages 2-7 ("Matrix Application and Definitions"). Projects should be scored as though at in-service. In other words, the matrix score should reflect conditions that are anticipated to exist at in-service date.
2. Complete the Matrix Scoring Sheet in the Excel template (link at: blank Matrix Score Sheet). For every Goal that applies:
    a. Assess the Level that applies for each Factor within the Goal, and highlight that cell.
    b. Multiply the Factor Weight against the Probability Level's point value and the Consequence Level's point value to establish a Goal score.
    c. Provide explanations in the Comments column to support the ranking for every Goal and Factor that applies.
    d. Probabilities and consequences should be based on historical occurrences and/or expected status in future years with consideration of long implementation durations for multi-year projects.
3. The overall Matrix score for the project is to be calculated and will be converted into a Tier ranking based on the following:

Matrix score	**Ranking**
≥ 1,200	Tier 1
850 – 1,199	Tier 2
550 – 849	Tier 3
200 – 549	Tier 4
< 200	Tier 5

4. Determine whether the project falls under any one of the following "Mandatory Project" criteria:
    - involves new customer hook-ups/connections or customer upgrades (including alternative energy projects, projects where legal agreements have been signed, and projects arising from Manitoba Infrastructure & Transportation or other government body), or
    - is driven by non-compliance with regulations (e.g., PCB elimination program), or
    - is directed by our Vice-President.

    If so, replace the Tier calculated by the sheet with "Mandatory" and add text to the Comments column to explain why.
5. Record the Tier ranking followed by the Matrix score in brackets, or the word "Mandatory", on the project budget document (i.e. on the CPJ title page or under the CER justification) as appropriate.
6. Forward the Matrix Scoring Sheet via email to the Finance Contact (copy to the Capital Projects Engineer). CPJs and CERs on applicable projects will not be processed unless the Matrix Scoring Sheet is completed and submitted as required.

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects
Matrix Application and Definitions

GOAL: **SAFETY**

GOAL STATEMENT:
Foster a work environment where employees are safe, valued and engaged.

GOAL APPLICATION WITHIN MATRIX:
This Goal applies if the project has a direct link to reducing the probability and/or consequence of a risk to public or employee safety. In order to qualify for points under this Goal the project must have been justified, at least in part, based on safety concerns. Temporary measures to mitigate safety risks, such as operational restrictions, should be ignored when scoring.

Note: the potential impacts of long-term power outages are to be addressed under the Service & Reliability Goal.

WEIGHT	GOAL - Factor	Level 1 (= 10 points)	Level 2 (= 7 points)	Level 3 (= 5 points)	Level 4 (= 2 points)	Level 5 (= 0 points)
10.0	**SAFETY**					
	- **Probability** of risk to public or employee safety	**HIGH**	**MEDIUM-HIGH**	**MEDIUM**	**LOW**	**DOES NOT APPLY**
	Definitions:	- *Immediate*	- *Within 2 years*	- *Between 2 & 5 years*	- *Beyond 5 years*	
	- **Consequence** of risk to public or employee safety	**HIGH**	**MEDIUM-HIGH**	**MEDIUM**	**LOW**	**DOES NOT APPLY**

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects

Matrix Application and Definitions

GOAL: SERVICE & RELIABILITY

GOAL STATEMENT:
Deliver reliable, quality power.

GOAL APPLICATION WITHIN MATRIX:
This Goal applies if the project has a direct link to reducing the probability and/or consequence of an event affecting service to a customer or reliability of the transmission or communications system. NOTE: Consequence may be scored under only Service or System Reliability or Communications; not more than one.

WEIGHT	GOAL - Factor	Level 1 (= 10 points)	Level 2 (= 7 points)	Level 3 (= 5 points)	Level 4 (= 2 points)	Level 5 (= 0 points)
10.0	**SERVICE & RELIABILITY**					
	- **Probability** of event affecting service to a customer or reliability of the transmission system	**CERTAIN**	**HIGH**	**MEDIUM**	**LOW**	**DOES NOT APPLY**
	Definitions:	*- Has already happened and is likely to happen again, or* *- Steady State*	*- Within 2 years, or* *- Single contingency*	*- Between 2 & 5 years, or* *- Two or more contingencies*	*- Beyond 5 years, or* *- Extreme contingencies*	
	- **Consequence** a) of event affecting **service to a customer**	**HIGH**	**MEDIUM-HIGH**	**MEDIUM**	**LOW**	**DOES NOT APPLY**
	Definitions: OR	*- # of residential & small commercial Customers affected is >30,000, or* *- Top 25 customer affected or firm Transmission export customer, or* *- Customer outage > 20 hrs*	*- # of residential & small commercial Customers affected is > 10,000 and ≤ 30,000, or* *- General Service Large customer affected, or* *- Customer outage > 12 hrs and ≤ 20hrs*	*- # of residential & small commercial Customers affected is > 2,000 and ≤ 10,000, or* *- General Service Medium customer affected, or* *- Customer outage > 4 hrs and ≤ 12 hrs*	*- # of residential & small commercial Customers affected is > 0 and ≤ 2,000, or* *- Customer outage ≤ 4 hrs*	

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects

Matrix Application and Definitions

WEIGHT	**GOAL** - Factor	**Level 1** (= 10 points)	**Level 2** (= 7 points)	**Level 3** (= 5 points)	**Level 4** (= 2 points)	**Level 5** (= 0 points)
	SERVICE & RELIABILITY (cont'd) - **Consequence** (cont'd)					
	b) of event affecting **reliability of the transmission system** *Definitions:* **OR**	**HIGH** - *Capacity or load loss > 100MW*	**MEDIUM-HIGH** - *Capacity or load loss > 50MW & ≤ 100MW*	**MEDIUM** - *Capacity or load loss > 10MW and ≤ 50MW*	**LOW** - *Capacity or load loss >0MW and ≤ 10MW*	**DOES NOT APPLY**
	c) of event affecting **reliability of the communications system** *Definitions:*	**HIGH** - *Frequent failures affecting multiple business critical systems, or* - *Teleprotection for >100MW, or* - *Control & telemetry for > 500MW, or* - *Voice & data for > 300 staff*	**MEDIUM-HIGH** - *Occasional failures affecting multiple business critical systems* - *Teleprotection for >50MW and ≤ 100MW, or* - *Control & telemetry for > 100MW and ≤ 500MW, or* - *Voice & data for > 100 and ≤ 300 staff*	**MEDIUM** - *Frequent failures affecting 1 business critical system* - *Teleprotection for >10MW and ≤ 50MW, or* - *Control & telemetry for > 50MW and ≤100MW, or* - *Voice & data for > 30 and ≤ 100 staff*	**LOW** - *Occasional failures affecting 1 business critical system* - *Teleprotection for ≤ 10MW, or* - *Control & telemetry for ≤ 50MW, or* - *Voice & data for 1-30 staff*	**DOES NOT APPLY**

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects
Matrix Application and Definitions

GOAL: FINANCIAL IMPACT

GOAL STATEMENT:
Improve corporate financial strength.

GOAL APPLICATION WITHIN MATRIX:
This Goal applies if the recommended option for the project has a positive Net Present Value (NPV), or significant average avoided expenditures per year. Note that points may be scored under only one of the two Factors; not both. Benefits associated with energy conservation or reduction of losses may be included in NPV calculation or total average avoided cost per year. Points for avoided costs under the Finance goal should not relate to cost differences between different options or alternatives. The avoided cost should be based on the difference between the current real-life state and to the chosen alternative.

WEIGHT	GOAL - Factor	Level 1 (= 10 points)	Level 2 (= 7 points)	Level 3 (= 5 points)	Level 4 (= 2 points)	Level 5 (= 0 points)
5.0	**FINANCIAL IMPACT**					
	- **Probability** of achieving financial impact	**CERTAIN**		**LIKELY**		**DOES NOT APPLY**
	- **Consequence** Net Present Value *Definitions:* **OR**	**NPV > $1,000,000** - *The present value of the estimated benefits is more than $1,000k greater than the present value of the estimated costs*	**NPV > $100,000 and ≤ $1,000,000** - *The present value of the estimated benefits is between $100k and $1,000k greater than the present value of the estimated costs*	**NPV > $0 and ≤ $100,000** - *The present value of the estimated benefits is between $1 and $100k greater than the present value of the estimated costs*		**NPV ≤ $0** - *The present value of the estimated benefits is equal to or less than the present value of the estimated costs*
	- Total average avoided cost per year, such as: • lost revenue; • the purchase of make-up power; • penalty payments; • regulatory sanctions, and/or • savings to O&M costs.	**> $250k per year**	**> $100k and ≤ $250k per year**	**> $30k and ≤ $100k per year**	**> $0 and ≤ $30k per year**	**DOES NOT APPLY**

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects

Matrix Application and Definitions

GOAL: TRANSFER CAPABILITY

GOAL STATEMENT:
Maximize export power net revenues.

GOAL APPLICATION WITHIN MATRIX:
This Goal applies if the project has a direct link to increasing or maintaining Manitoba Hydro's export transmission system transfer capability.

WEIGHT	GOAL - Factor	Level 1 (= 10 points)	Level 2 (= 7 points)	Level 3 (= 5 points)	Level 4 (= 2 points)	Level 5 (= 0 points)
5.0	**TRANSFER CAPABILITY**					
	- **Probability** of impact to transfer capability			**50% FOR ALL PROJECTS**		**DOES NOT APPLY**
	- **Consequence** - Increase or prevent the loss of transfer capabilities	**INCREASE > 50MW**	**INCREASE >10MW and ≤ 50MW**	**INCREASE > 0MW and ≤ 10MW**	**PREVENT LOSS OF EXISTING TRANSFER CAPABILITY**	**DOES NOT APPLY**
	Definitions:	- *Tie-line Transfer >50MW, or* - *Un-bottled Generation >50MW*	- *Tie-line Transfer >10MW and ≤50MW, or* - *Un-bottled Generation >10MW and ≤50MW*	- *Tie-line Transfer >0MW and ≤ 10MW, or* - *Un-bottled Generation >0MW and ≤ 10MW*		

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects
Matrix Application and Definitions

GOAL: **ENVIRONMENT**

GOAL STATEMENT:
Be respectful of the public and the environment

GOAL APPLICATION WITHIN MATRIX:
This Goal applies if the project has a direct link to reducing the probability and/or consequence of a negative impact to the environment, or increasing the probability and/or consequence of achieving a positive impact to the environment. In order to qualify for points under this Goal the project must have been justified, at least in part, based on environmental concerns.

WEIGHT	**GOAL** - Factor	**Level 1** **(= 10 points)**	**Level 2** **(= 7 points)**	**Level 3** **(= 5 points)**	**Level 4** **(= 2 points)**	**Level 5** **(= 0 points)**
5.0	**ENVIRONMENT**					
	- **Probability** of negative or positive impact to the environment *Definitions:*	**HIGH** - *Within 2 years*		**MEDIUM** - *Between 2 & 5 years*	**LOW** - *Beyond 5 years*	**DOES NOT APPLY**
	- **Consequence** of negative to positive impact to the environment *Definitions:*	**HIGH** - *Impact is widespread and uncontained, or* - *Significant impact to Corporate image*		**MEDIUM** - *Impact is local and uncontained, or* - *Moderate impact to Corporate image*	**LOW** - *Small area affected and contained, or* - *Low impact to Corporate image*	**DOES NOT APPLY**

CAPITAL BUDGET RANKING TOOL for use on TRANSMISSION Projects

Matrix Scoring Sheet

See the CAPITAL BUDGET RANKING TOOL DOCUMENTATION for instructions and definitions.

I.M. #
WBS # (if Domestic)

NAME OF PROJECT:

Prepared by: name, department

Date: yyyy/mm/dd

Scoring: (Weight) x (Probability points) x (Consequence points)

Weight	TRANSMISSION GOAL - Factor	Level 1 (=10 points)	Level 2 (=7 points)	Level 3 (=5 points)	Level 4 (=2 points)	Level 5 (=0 points)	GOAL SCORES	COMMENTS / RATIONALE (Required) (do not split cells; press {Alt}{Enter} to start a new line / paragraph)
10	**SAFETY**							
	Probability of risk to public or employee safety	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	Consequence of risk to public or employee safety	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
10	**SERVICE & RELIABILITY**							
	Probability of:							
	- event affecting service to a customer **OR**	CERTAIN	HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the transmission system	CERTAIN	HIGH	MEDIUM	LOW	does not apply		
	Consequence of:							
	- event affecting service to a customer, **OR**	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the transmission system, **OR**	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
	- event affecting reliability of the communications system	HIGH	MEDIUM-HIGH	MEDIUM	LOW	does not apply		
5	**FINANCIAL IMPACT**							
	Probability of achieving financial impact	CERTAIN		LIKELY		does not apply		
	Consequence:							
	- Net Present Value, **OR**	> $1,000k	> $100k and ≤ $1,000k	> $0 and ≤ $100k		≤ $0		
	- Average avoided cost per year	> $250k	> $100k and ≤ $250k	> $30k and ≤ $100k	> $0 and ≤ $30k	does not apply		
5	**TRANSFER CAPABILITY**							
	Probability of impact to transfer capability			ALL PROJECTS		does not apply		
	Consequence of increase to or prevent loss of transfer capability	MW INCREASE > 50	MW INCREASE > 10 and ≤ 50	MW INCREASE > 0 and ≤ 10	PREVENT LOSS	does not apply		
5	**ENVIRONMENT**							
	Probability of negative or positive impact	HIGH		MEDIUM	LOW	does not apply		
	Consequence of negative or positive impact	HIGH		MEDIUM	LOW	does not apply		

Tier 1 ≥ 1,200; Tier 2 = 850-1,199; Tier 3 = 550-849; Tier 4 = 200-549 & Tier 5 < 200

MATRIX SCORE: 0 = TIER 5

Template Revision Date: 2015.01.12

REFERENCE:

PUB MFR 106 – Sustaining and Major Capital, Page 1 of 2; PUB/MH I-82a-b

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB/MH I-82 (a) ii.

“Bipole II Valve Hall Bushing Replacements: See PUB MFR 93 (page 3 of 6) for a description of the project and PUB MFR 115 Attachment 1 (Appendix 32) for the Capital Project Justification. Under CEF15 this investment was planned for 2019/20 to 2022/23; however, under CEF16 some of the replacements ($2.8M or 15% of the project total) were advanced to 2017/18 and 2018/19, as recent assessments found some bushings were in very poor condition and must be replaced right away to avoid catastrophic in-service failure.”

Reference: Manitoba Hydro Response to PUB/MH I-82 (b) ii.

“Bipole II Valve Hall Bushing Replacements: See PUB MFR 93 (page 3 of 6) for a description of the project and PUB MFR 115 Attachment 1 (Appendix 32) for the Capital Project Justification. Under CEF15 this investment was planned for 2019/20 to 2022/23; however, under CEF16 the majority of bushing replacements ($16.3M or 85% of the project total) were deferred to 2021/22 to 2024/25 to coincide with the schedule for the Bipole II Thyristor Valve Replacements. The thyristor valve replacements are planned in recognition that these are already amongst the oldest still in service in the world and will entail a very complex and time-consuming project that calls for long-term planning.”

QUESTION:

a) Please provide risk evaluations for each example included in Manitoba Hydro’s response to PUB/MH I-82a-b:
   i. SF Transformer Banks 2, 3 & 4 Replacement;
   ii. Bipole II Valve Hall Bushing Replacements;
   iii. Adelaide Station;
   iv. Overhaul of Slave Falls Units 1 and 2; and

v. 66 kV Line 20 Rebuild.

b) The response in part b) ii. of PUB/MH I-82 is contradictory to the answer given in part a) ii. which states that bushing replacements were accelerated due to the advanced deterioration state of the assets and risk to system. Part b) ii. states that most of the bushing replacements were deferred until 2021/22 to 2024/25, which indicates that many of the replacements are not urgent. Please reconcile these responses.

RATIONALE FOR QUESTION:

RESPONSE:

a) i. The Slave Falls Transformer Banks 2, 3, and 4 Replacement Investment was raised due to the rapidly degrading condition of all of these transformers and the system requirement for continued generation from these six units. The following risks will be mitigated and benefits realized with the investment:

Risk/Benefit	Description	Consequence Description	Value of Consequence	Annual Probability of Occurrence Prior to the investment	Probability of Occurrence After to the investment
Lost Generation Risk	The lost revenue impact of a transformer failure.	Due to the configuration of the transformer banks at the Slave Falls GS the loss of any one of the transformers would result in the loss of two units of generation at Slave Falls for a period greater than a year.	$4M	Almost Certain (95% chance) that one of the three units will fail These banks are currently showing failure indications. Monitoring and maintenance has increased to ensure that a failure does not result in the worst case scenario.	.1%

Risk/Benefit	Description	Consequence Description	Value of Consequence	Annual Probability of Occurrence Prior to the investment	Probability of Occurrence After to the investment
Financial Risk	The financial impact of damage to surrounding equipment.	1 out of every 10 transformers that fails in service is sited to fail catastrophically (fire or explosion, exposing surrounding equipment or people to unfavorable conditions). The estimated value of the equipment at risk during a catastrophic failure	$1.5M	10% Risk that one of the units will have a catastrophic failure (1/10)	none

ii. Bipole II Valve Hall Bushing Replacements risk evaluation is described in Engineering Report HVDC-07-08E (Attachment 6 in PUB MFR 93) and Capital Project Justification (Attachment 32 on PUB MFR 115)

iii. Adelaide Station risk evaluation was a qualitative analysis as described in PUB MFR 93 Attachment 9, pages 25 – 43 (Adelaide Planning Study).

iv. The Slave Falls Units 1+2 Overhaul Investment was raised because the units were in poor (or very poor) condition. The economic analysis compared the cost of the investment to the revenue associated with continued operation. This would be equivalent to assuming a 100% probability of failure. Even with this conservative assumption the economics did not favor proceeding with the investment, as described in PUB MH II-5, so a more detailed risk assessment was not conducted.

v. The risk assessment for the 66 kV Line 20 Rebuild project considered safety, the line condition, capacity and impact on reliability. Since this line was already experiencing outages regularly, the probability of an outage event was deemed to be ‘high’. However, since the line served relatively few customers and there were no present or forecasted capacity concerns, the consequence of these outages was deemed to be ‘medium’. There was no safety concerns associated with the condition of the line. The resulting risk level was lower relative to other identified line refurbishment projects causing its deferral.

b) The response in parts a) and b) of PUB/MH I-82 are not contradictory. The bushings in the population referred to in this response present varying levels of risk to the system due to the varying conditions of the bushings. Part a) describes the need to accelerate 15% of the requirement to meet immediate needs of replacing bushings in the population that are in very poor condition to mitigate risk of catastrophic failure. The remaining 85% of the budget was deferred as described in Part b).

101

REFERENCE:

PUB MFR 10 – Financial Information, Page 1 of 2.

PREAMBLE TO IR (IF ANY):

"There are a number of significant changes in Manitoba Hydro's current financial plan (MH16) compared to its previous financial plan (MH15). These changes include:

"MH16 reflects a deterioration of the expectations for domestic load growth. As a result, the domestic revenue forecast is 5% lower at current approved rates."

QUESTION:

Does the expectation of lower domestic load growth mitigate the impact of asset demographic risk and the requirement to add new transmission and distribution capacity?

RATIONALE FOR QUESTION:

Does Manitoba Hydro's reduced load forecast lower the urgency of replacing aged assets or adding new capacity to the Transmission and Distribution systems?

RESPONSE:

The provincial Electric Load Forecast is a study of overall system load requirements for energy and capacity on an aggregated basis. While this is important for resource and financial planning purposes, it is not particularly useful for system planning purposes.

System planning must address loading and operating conditions on a localized basis, across the whole system. The expectation of lower domestic load growth does not immediately impact the requirement for new transmission and distribution capacity, for the following reasons:

- The provincial Electric Load Forecast is designed to derive the overall loading for the entire Province. Planning studies investigate load requirements within regions or segments of the transmission and distribution systems. Load growth in a particular region will be dependent upon the localized trends in industrial, commercial and residential activity within that region. Trends in load growth are also dependent on the loading season. The attachment to this response demonstrates these facts through a mapping of summer and winter load growth projections across five regions of the province based on 2016 studies.

- In some cases, the load in a region already exceeds the firm capacity of that area's transmission or distribution system, so even if the forecast load is growing at a reduced rate Manitoba Hydro may already be in a position where it cannot meet the existing load under certain operating conditions.

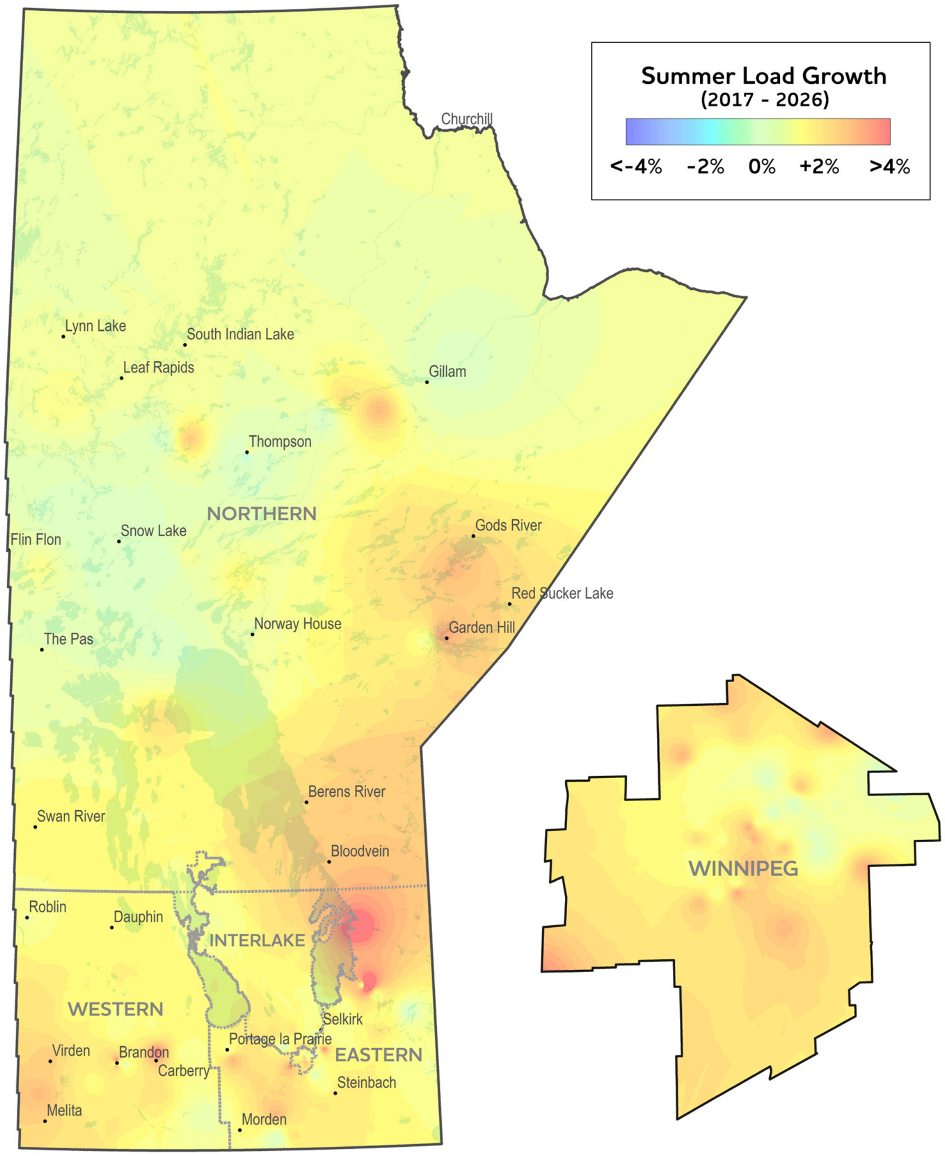
The capacity-related investments in the Capital Expenditure Forecast target the "capacity hot spots" in the province where load growth is higher than the provincial average or already exceeds the available capacity. Additional information about the need for capacity-related investments can be found in the response to PUB/MH I-118a-c.

The expectation of lower domestic system load growth may mitigate increases of some asset demographic risks because lower load growth rates will tend to reduce the growth of potential reliability consequences of major transmission system equipment failures, such as transformer failures. However, as with the requirement for new capacity, the load, and hence the reliability risk of asset failures may grow more rapidly in some parts of the province than in other parts.

Summer Load Growth Projections

	Northern	Western	Interlake	Eastern	Winnipeg	Totals
2017 MW Loads	448.93	727.75	197.14	493.16	1455.68	3322.67
2026 MW Loads	431.03	802.08	212.78	603.06	1652.97	3701.90
Annual Growth Rate	**-0.44%**	**1.13%**	**0.88%**	**2.48%**	**1.51%**	**1.27%**

The above summer load projections are based on an average per year growth, between the years 2017 and 2026. These projections are based on non-coincident peak station loads. The largest growth region appears to be the Eastern region showing a per year average summer seasonal growth of approximately 2.5%. The Northern region shows a small decline in growth of approximately -0.4%. Total provincial load projections show an average summer seasonal per year growth of approximately 1.3%.

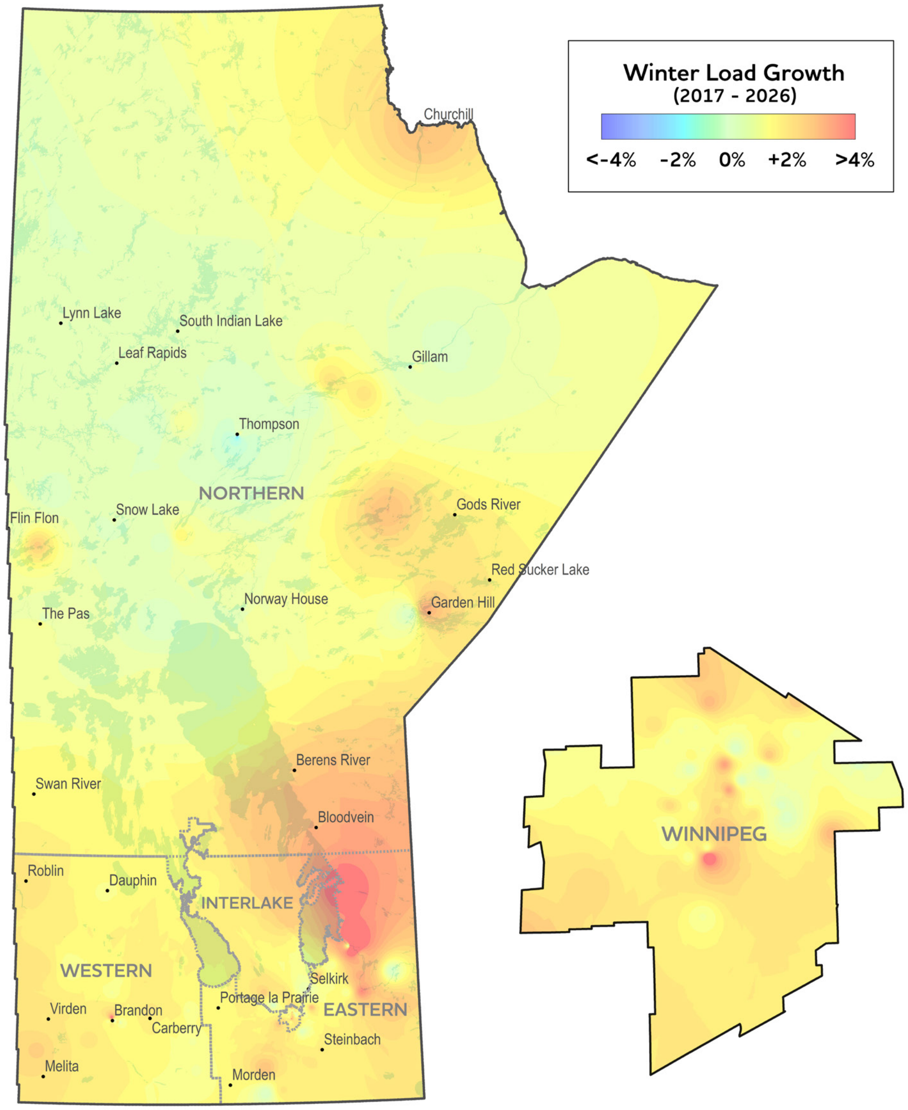


Heat map displays load growth using Inverse Distance Weighted interpolation.
Where load transfers occur, aggregate load growth is shown at each station.

Winter Load Growth Projections

	Northern	Western	Interlake	Eastern	Winnipeg	Totals
2017 MW Loads	815.20	1073.58	346.04	754.44	1511.22	4500.47
2026 MW Loads	849.40	1165.31	427.32	1053.07	1657.22	5152.32
Annual Growth Rate	**0.47%**	**0.95%**	**2.61%**	**4.40%**	**1.07%**	**1.61%**

The above winter load projections are based on an average per year growth, between the years 2017 and 2026. These projections are based on non-coincident peak station loads. The largest growth region appears to be the Eastern region showing a per year average winter seasonal growth of approximately 4,4%. The Northern region shows the smallest growth of approximately 0.5%. Total provincial load projections show an average winter seasonal per year growth of approximately 1.6%.



Heat map displays load growth using Inverse Distance Weighted interpolation.
Where load transfers occur, aggregate load growth is shown at each station.

102

REFERENCE:

Business Operations Capital and Asset Management Technical Conference presentation, July 20, 2017, Slide 15; PUB/MH I-118b

PREAMBLE TO IR (IF ANY):

Reference: Manitoba Hydro Response to PUB/MH I-118 b-c-Attachments

Transmission Planning & Design Division System Planning Department Report On Steinbach Area 230-66 kV Capacity Enhancement SPD 2014102
p. 3:

> "The new Grunthal terminal station will consist of two 230-66 kV, 140 MVA transformers, four 230 kV circuit breakers, six 66 kV circuit breakers, associated communications, and up to 150 km of 66 kV lines. It's estimated that the installation cost for this project is approximately $68.9 million. The recommended in-service date for this project is 2018-10-31. This project will replace the existing St. Vital-Steinbach 230 kV Transmission complex, which is currently estimated to cost approximately $32 million with a 2020-10-31 in-service date. The current complex and estimate are considered outdated, and would likely cost closer to $81.5 million based on current requirements and estimating."

7.2.1. Option 1: Existing St. Vital-Steinbach 230 kV Transmission Complex
p. 12:

> "This project as described would not be adequate for satisfying current planning criteria. A single contingency loss of either the one transformer or the single radial line would remove the new 230-66 kV station from service, and would require the attached load to be transferred to surrounding stations such as Richer South station, St. Vital station, and Letellier station. This combined with the current loading at Richer South station and St. Vital station would result in Richer South station being over firm transformation and St. Vital being over firm transformation. Richer South station would be over 100 MVA of loading which could lead to additional 230 kV voltage concerns during a 230 kV line contingency of R49R. It's also predicted that

> 66 kV voltages in the area would become low due to the loading in the area, which would need to be verified by 66 kV Planning."

p. 14:

> "Total Estimated Cost $81,500,000
>
> This estimated cost also doesn't include any new 66 kV line or 66 kV line rebuilds that would be required to support the capacity of the new Steinbach station, which would drive the total estimated cost even higher."

7.2.2. Option 2: New Grunthal Area 230-66 kV Station
p. 16:

> "Total Estimated Cost $68,900,000".

QUESTION:

a) Does the statement: "Richer South station would be over 100 MVA of loading which could lead to additional 230 kV voltage concerns during a 230 kV line contingency of R49R," indicate that Manitoba Hydro is evaluating the effectiveness of this project alternative on the basis of a double contingency, i.e.: N-2 or N-1-1?
   i. If yes, would this be considered a conservative approach to take when evaluating planning alternatives?
   ii. Is the 100 MVA Richer South station loading described in the contingency based on coincident peak load, non-coincident peak load, average winter loading or some other load condition?
   iii. If 100 MVA is a peak load condition, what is the load duration period for which the studied load condition would exist each year?

b) Please compare the initial 1997 estimate of $32 million for Option 1 against the 2013 estimate of $81.5 million that is broken out on p. 14 of the planning report. Please identify the cost increases for scope items that are common to these estimates, and separately identify all scope changes between the estimates and the associated cost impacts. What would be the present total cost estimate for the revised scope?

c) The 2013 estimate for Option 2: New Grunthal Area 230-66 kV Station was $68,900,000. What is the current estimated cost for this option, broken out by the same cost items shown in the planning report? Does this Option address all of the planning issues that would have been addressed by Option 1? Please explain in detail.

RATIONALE FOR QUESTION:

To determine how Manitoba Hydro develops project estimates and the planning criteria that are applied when comparing project alternatives for planning purposes.

RESPONSE:

a) The statement was made on the basis of a single N-1 contingency loss of R49R, and is not contingent on N-2 or N-1-1. This condition is present anytime station load at Richer South station exceeds 100 MVA, and not necessarily at peak. Over the past 5 years, Richer South station has spent an average of approximately 136 hours per year in the winter over 100 MVA, ranging anywhere from 1 hour in 2015/16, to 421 hours in 2016/17 largely dependent on weather. The expectation is that the average amount of time over 100 MVA at Richer South station will grow over time as load grows.

b) Please see the attached.

c) Please see the attached. Option 2 addresses all the planning issues addressed by the Option 1 (expanded 2013 scope). Option 2 also had the additional planning benefit of making use of the planned St. Vital –Letellier 230 kV transmission line, avoiding the need to build an additional 230 kV transmission.

PUB-MH II-84b-c
Steinbach Area 230-66kV Capacity Enhancement (SPD 2014-02)

b) Comparison of the initial 1997 estimate with the 2013 estimate for Option 1		**Previous Estimate for Previous Concept & Scope, in 1997$**	Updated Estimate for Previous Concept & Scope, in 2013$	Estimate for Additional Scope, in 2013$	**Updated Estimate for Previous Concept & Added Scope, in 2013$**
1	Construction of a 230-66kV station near Steinbach with one transformer (see Note)	$5.9	$27.3		$27.3
2	Construction of 40.2km of 230kV transmission line from St. Vital Station to the new Steinbach station, and removal of 23.5km of 115kV transmission line VJ50 (St. Vital – Hanover).	$9.3	$20.1		$20.1
3	Termination at St. Vital Station of the new 230kV transmission line from the new Steinbach station.	$2.3	$3.0		$3.0
4	Communications for the new station and transmission line.	$0.7	$1.8		$1.8
5	Addition of a second 230-66kV, 95MVA transformer at the new Steinbach station.			$10.0	$10.0
6	Construction of 20km of 230kV line from the new Steinbach station to Richer South station.			$10.0	$10.0
7	Termination at Richer South station of the new 230kV line from the new Steinbach station.			$2.5	$2.5
8	Salvage Hanover station, Randolph station and 40.2km of 115kV transmission line VJ50 (St. Vital-Hanover)			$6.8	$6.8
9	Interest & Escalation	$13.9	not calc'd	not calc'd	not calc'd
Total Net Cost		$32.2	not calc'd	not calc'd	not calc'd
Total Cost without Interest & Escalation		$18.3	$52.2	$29.3	$81.5
Net Present Value for Revised Scope & Cost					($64.8)

Note: the original concept sized the transformer at 83.3MVA while the updated concept calls for an 95MVA transformer.

c) Current estimate for Option 2		**Total Estimate for Revised Concept, in 2013$**
1	Construct a new 230-66kV station in the Grunthal area, complete with one 230-66kV, 140 MVA transformers with On-Load Tap Changer (OLTC), two grounding transformers, a four 230kV circuit breaker ring, and a 66kV ring.	$30.5
2	Add a second 230-66kV, 95MVA transformer at the new Grunthal station	$10.0
3	Construct 150km of 66kV line to tie in existing 66kV system and transfer load from Hanover, Richer South, St. Vital and Letellier stations	$25.0
4	Salvage Hanover station and 11km of VJ50 (St. Vital-Hanover)	$3.4
5	Interest & Escalation	$15.6
Total Net Cost		$84.5
Total Cost without Interest & Escalation		$68.9
Net Present Value for Revised Concept		($58.0)

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REFERENCE:

Tab 5 Figure 5.10 Pg. 25 of 28

PREAMBLE TO IR (IF ANY):

"Electric Business Operational Capital 10 Year Forecast by Investment Category"

QUESTION:

b) Please indicate what proportion of the Investment in each Category is considered by Manitoba Hydro to be non-volitional and therefore not able to be considered for deferral.

c) Explain why the volitional project and programs are being done in the test years.

d) Please explain why all non-volitional projects and programs in each Business Unit during the planned test years cannot be deferred without incurring unacceptable risk. Please express risk in terms of probability and consequence for each project and program.

RATIONALE FOR QUESTION:

RESPONSE:

b) The following table provides the percentage of the investments in each Category that could not be deferred for fiscal year 2018/19. The information provided is representative of the percentage of the portfolio that cannot be deferred in a one year outlook. Any projects or programs that were started prior to fiscal year 2018/19 cannot be deferred.

Investment Category		Proportion of Category That Could not be Deferred in FY2018/19
Capacity and Growth	System Load Capacity	98%
	Customer Connections	100%
Sustainment	System Renewal	58%
	Mandatory Compliance	100%
	System Efficiency	81%
	Decommissioning	51%
Business Operations Support	Information Technology	7%
	Fleet	0%
	Corporate Facilities	0%
	Tools and Equipment	27%
	Town site Infrastructure	50%
	Generation Building and Grounds	0%

c) The projects and programs that could be deferred, but were not deferred in 2016/17, 2017/18 and 2018/19 have been deemed to be priority projects by the capital planning process as described in PUB/MH I-119a-c. These investments are either mitigating one or more of the significant operational risks described in PUB/MH I-119a-c, are critical to operations or take advantage of opportunities to increase operational efficiency.

d) The projects and programs ineligible for deferral are either legislated requirements, replacing run to failure assets that have failed or are too far into execution to defer economically.

Legislated requirements are captured as Mandatory Compliance and Customer Connections investment categories. Deliberate non-compliance with a legislated requirement is unacceptable, as is deferring customer connections.

Some assets are considered run to failure. When these assets fail it is critical to replace them to maintain systems operations and a safe environment for staff and the public.

Projects and programs in execution with significant progress and spending are ineligible for deferral due to the extra costs of interrupting and restarting the work, or the write off of sunk costs if the work is cancelled.

The risks associated with deferring the types of projects described in the preceding paragraphs are unacceptable in that the probability of non-compliance or a customer not being connected, disrupting operations, creating an unsafe environment or incurring extra costs on executing projects is almost certain if the projects or programs are deferred.

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REFERENCE:

Past Board Orders

PREAMBLE TO IR (IF ANY):

Table of Concordance of Past Board Orders related to Asset Management and Asset Condition Assessments (in reverse chronological order).

Board Order Reference No.	**Order Summary**
Order No. 59/16 (Page 31 of 43)	The Board is again requesting the Terms of Reference and schedules for these two assessments be filed with the Board by April 15, 2016.
Order No. 59/16 (Page 31 of 43)	The Board will require Manitoba Hydro to file the complete asset condition assessment information for generation, transmission, and distribution at the next General Rate Application.
Order No. 73/15 (Page 8 of 108)	The Board directs Manitoba Hydro to file terms of reference for a more comprehensive asset condition assessment report before approving the rate impacts from increased sustaining capital spending for future years.
Order No. 73/15 (Page 65 of 108)	The Board directs Manitoba Hydro to provide a more robust asset health assessment and capital asset management strategy for the next General Rate Application (GRA).
Order No. 73/15 (Page 68 of 108)	The Board expects Manitoba Hydro to file, by October 31, 2015, updated Terms of Reference and schedules for an Asset Condition Assessment. The schedules should contemplate completion of the Assessment in advance of the next GRA. In the Board's view, the Terms of Reference should, at minimum, include the items set out in Appendix G of this Order.
Order No. 73/15 (Page 97 of 108)	Manitoba Hydro shall file terms of reference for an Asset Condition Assessment Report for approval by the Board that, at minimum, include the information set out in Appendix "F" of this Order, by no later than October 31, 2015.

Board Order Reference No.	Order Summary
Order No. 43/13 (Page 5 of 62)	That Manitoba Hydro complete and file with the Board an Asset Condition Assessment Study no later than the filing of the next updated depreciation study with the Board.
Order No. 5/12 (Page 105 of 232)	The Board will require MH to file an Asset Condition Assessment and depreciation study at the next GRA.
Order no. 150/08 (Page 26 of 82)	The Board will vary the existing Directive, by requiring MH to file proposed Terms of Reference for a future Asset Condition Assessment Report by June 30, 2009.
Order No. 116/08 (Page 101 of)	The Board notes Mr. Harper's suggestion that as a best practice, MH should undertake an Asset Condition Assessment.
Order No. 116/08 (Page 102 of)	The Board directs MH to undertake and file with the Board an Asset Condition Assessment by June 30, 2009, that defines: ○ major assets and categories of assets; ○ the estimated remaining economic life of each major asset and category of asset; ○ an indication of the implications for OM&A costs related to maintaining required and scheduled maintenance; ○ a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets; ○ forecast expenditures for planned renovations and/or replacements with respect to now-available energy supply and transmission; and ○ Dam Safety Condition Assessment and Maintenance requirements.

QUESTION:

For the line items excerpted from the Board Orders in the above table, please provide the following information:

a) Plan: Manitoba Hydro's implementation plan for each of the items.
b) Schedule: The expected schedule for fully implementing each item.
c) Status: The current status of Manitoba Hydro's implementation plans. For line items not being implemented, the status should include Manitoba Hydro's justification for not complying with the order.

NOTE: Please highlight any differences in implementation plans, schedules, and/or statuses across the business units: i) Generation, ii) Transmission and iii) Customer Service & Distribution.

RATIONALE FOR QUESTION:

To assess Manitoba Hydro's level of compliance with numerous past Board Orders related to Asset Condition Assessments and Asset Management.

RESPONSE:

Manitoba Hydro has provided the following chronology to illustrate the information that has been provided by the Corporation in compliance with the PUB's directives for Manitoba Hydro to file an Asset Condition Assessment report.

Board Order	
Order 116/08	On September 18, 2008, Manitoba Hydro filed an Application for a Review and Vary of Order 116/08, including Directive 7. On November 7, 2008, the PUB issued Order 150/08 varying Directive 7 of Order 116/08 as follows: *MH to undertake and file with the Board an Asset Condition Assessment Report by June 30, 2009 a date to be fixed by the Board after its review of the Terms of Reference to be filed by MH by June 30, 2009, that defines:* *a) major assets and categories of assets;* *b) the estimated remaining economic life of each major asset and category of asset;* *c) an indication of the implications for OM&A costs related to required and scheduled maintenance;* *d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;* *e) forecast expenditures for planned renovations and/or replacements with respect to now available energy supply and transmission; and* *f) Dam Safety Condition Assessment and Maintenance requirements.* *In advance of the commencement of the Asset Condition Assessment Study, MH to tile [sic] with the Board detailed Terms of Reference containing the scope for undertaking such a study and a definition of the resources to be employed, on or before June 30, 2009.* As part of Tab 13 of the 2010/11 & 2011/12 GRA, Manitoba Hydro indicated as follows: *Manitoba Hydro will consider the extent to which this issue can be addressed as part of its Depreciation Study (to be completed post-IFRS implementation) and will provide a specific timeline by April 1, 2010.* On April 1, 2010, Manitoba Hydro filed a letter indicating that the Depreciation Study would be conducted as part of IFRS implementation and that Manitoba Hydro would be in a better position to inform the PUB of the extent to which its directive has been addressed by April 1, 2012. In addition to the Depreciation study, Manitoba Hydro also noted that it was embarking on two asset related projects, including asset investment planning. A copy of this letter can be found as an Attachment to this response.

Order 5/12	In Order 5/12, the PUB acknowledged that the implementation of IFRS has prompted Manitoba Hydro to delay undertaking the PUB's requested studies, including an Asset Condition Assessment report, and required Manitoba Hydro to file an Asset Condition Assessment and depreciation study at the next GRA. Manitoba Hydro notes that the transition to IFRS was deferred on multiple occasions. Manitoba Hydro filed its 2012/13 & 2013/14 GRA on June 15, 2012. Manitoba Hydro provided an update on all its Directives and responded to numerous Information Requests on asset condition related topics. In particular, Manitoba Hydro highlights the filing of the Distribution Asset Condition report as Appendix 40. • PUB-MH-I-82b (PDF Page 523) - Manitoba Hydro provided a review of the status of asset condition reporting in each of its Business Units. • CAC-MH-I-38e (PDF Page 232) - Manitoba Hydro outlines initiatives undertaken to prioritize distribution asset rehabilitation programs and optimize asset utilization. • CAC-MH-II-15a (PDF Page 28) - Manitoba Hydro provided information related to the Applied Maintenance Planning System (AMPS), Reliability Centered Maintenance (RCM), and HydroAMP. • CAC/MH-II-54 (PDF Page 115) - Manitoba Hydro filed the Report on Future Projects for HVDC Converter Stations (as Appendix 39) and the Report on Distribution Asset Condition (as Appendix 40). • MH Exhibit #97 (Undertaking #81) - Manitoba Hydro provided an update on the Enterprise Asset Management system.

Order 43/13	In Order 43/13 issued April 26, 2013, the PUB acknowledged that Manitoba Hydro is enhancing its asset condition assessment tools and directed Manitoba Hydro to complete and file with the PUB an Asset Condition Assessment Study no later than the filing of the next updated depreciation study. Manitoba Hydro filed its 2014/15 & 2015/16 GRA on January 16, 2015. As part of its 2015 GRA, Manitoba Hydro filed its Electric Infrastructure Condition Assessment Summary as Appendix 4.2, which provided an overview of the most significant Manitoba Hydro generation, transmission, high voltage direct current (HVDC) and distribution asset conditions, demographics and a 20-year forecast of equipment condition based on current replacement rates and projected replacement or refurbishment work included in the Capital Expenditure Forecast 2013. With the information provided in Appendix 4.2, Manitoba Hydro considered the reporting requirements associated with Directive 7 of Order 150/08 to be complete, pending the PUB's review as part of the 2015 GRA. Manitoba Hydro also responded to numerous Information Requests on matters related to asset condition and the directive, in particular: • PUB/MH I-19a (PDF Page 161) - Manitoba Hydro outlined how Appendix 4.2 addressed items in Directive 7 of Order 150/08. • COALITION/MH I-11a (PDF Page 66), COALITION-MH I-93c (PDF Page 705), COALITION/MH II-40a-c (PDF Page 73) - Manitoba Hydro provided information related to its evaluation and prioritization of capital expenditures. • COALITION/MH II-53c-g (PDF Page 126) – Manitoba Hydro provided the Kinectrics report Manitoba Hydro 2012 Asset Condition Assessment for transmission assets. • MH Exhibit #100 (Undertaking #32) – Manitoba Hydro provide information on the quality of asset retirement data. • Manitoba Hydro also had a Planning & Operations Panel during the oral hearings that provided more technical information on asset condition and the corporate prioritization framework.

Order 73/15	Manitoba Hydro's understanding is that Directive 7 in Order 73/15 and Appendix G, superseded Directive 7 of Order 150/08. In Order 73/15, the PUB acknowledged that Manitoba Hydro is faced with aging infrastructure and there may be a need to expand sustaining capital expenditures, however the PUB stated that additional information with respect to the long term pacing and prioritization of capital requirements was needed, including updated Terms of Reference and schedules for an Asset Condition Assessment to be filed by October 31, 2015. As part of its 2016/17 Supplemental Filing, Manitoba Hydro filed a status update to directives in Attachment 26 (Corporate Overview MFR 2) filed on December 9, 2015, including Directive 7 of Order 73/15 (pages 2-3), and on January 11, 2016, filed Attachment 44 which included an overview of the asset management initiatives, including asset condition assessments and implementation of asset investment planning software (C55), and provided Terms of Reference for the Asset Condition Assessment of its distribution assets. Manitoba Hydro responded to numerous Information Requests on asset condition and asset management, including: • PUB/MH I-51a (PDF Page 330) - Manitoba Hydro provided Terms of Reference for the Corporate Value Framework (CVF), the CVF pilot for Generation Operations, and the pilot of the implementation of the transmission system reliability risk model in C55. • PUB/MH I-51c (PDF Page 338) – Manitoba Hydro provided the Terms of reference for the engagement of Kinectrics for the asset condition methodologies audit for HVDC, transmission and distribution system assets. • PUB/MH I-40a (PDF Page 286) - Manitoba Hydro provided a summary of the condition of assets, by asset type, for generating stations. • PUB-MH I-41a-c (PDF Page 293) – Manitoba Hydro provided an overview of the recommendations from the 2015 Kinectrics audit findings.

Order 59/16	In Directive 5 of Order 59/16, the PUB varied Directive 7 of Order 73/15 to no longer require the Asset Condition Assessment Report to differentiate assets based on geography, but to differentiate based on age and remaining life. As part of Tab 10 of the current GRA, Manitoba Hydro provided a status update on Directive 5 of Order 59/16, and in Tab 5 provided an overview of the enhancement initiatives underway with respect to asset health methodology and condition assessments. Manitoba Hydro has also filed the following asset condition reports and Terms of Reference: • Appendix 5.2 - Terms of Reference for the Capital Portfolio Management Program. • Appendix 5.3 - Kinectrics Asset Condition Assessment Audit results (HVDC, transmission and distribution assets). • PUB MFR 92: ○ Asset Condition Assessment report for key distribution system assets (Kinectrics) (Attachment 1). ○ Transmission Planning & Design Division, System Planning Department report on Asset Condition Assessment Methodology Standards & Result Updates (Attachment 3). ○ Condition assessment methodologies and reports for some generation plant assets (Attachment 4 – 10). • COALITION MFR 10: ○ Asset condition assessment methodology reports for generation assets (Attachment 2 to 16) • COALITION/MH I-160 - Kinectrics Report on Asset Degradation Curve Development for some transmission system assets Manitoba Hydro has provided available asset condition assessment reports for its generation, transmission and distribution assets, as per Directive 7 of Order 73/15. Timelines for asset refurbishment and/or replacement out to 2049/50 are not available, as specific asset replacements are not planned on this horizon for the breadth of assets listed in Appendix G. Rather, condition monitoring requirements and planning horizons are customized in managing the asset as a function of its operating context. For instance, run to fail asset replacements are not planned proactively and many assets are kept serviceable through regular maintenance such that they are not expected to be replaced within the life of the facility. In general, specific asset replacements are planned on relatively short horizons with longer

	term investments requirements forecasted in aggregate by asset class. Manitoba Hydro's Capital Planning Model (see Section 5.1.2 of the GRA) and Asset Investment Process Improvements (see Section 5.1.3 of the GRA) provide the terms of reference for achieving its objectives of optimizing the timing of investments to maximize value and forecasting the long term capital requirements of the Corporation.

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($ Millions)	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	2017-2036 20 Year Total
Major New Generation & Transmission	2 355	2 476	2 126	1 274	1 066	746	358	75	4	4	5	**8 134**	**10 491**
Electric Business Operations Capital	574	526	517	516	511	499	521	544	616	640	659	**5 549**	**12 835**
Natural Gas Business Operations Capital	51	31	32	29	31	33	35	34	39	39	40	**343**	**812**
Capital Expenditures Total	**2 980**	**3 033**	**2 675**	**1 819**	**1 609**	**1 278**	**914**	**652**	**659**	**683**	**703**	**14 026**	**24 138**
Year End Outlook Adjustment	(45)	-	-	-	-	-	-	-	-	-	-	**-**	**(45)**
Revised Capital Expenditures Total	**2 935**	**3 033**	**2 675**	**1 819**	**1 609**	**1 278**	**914**	**652**	**659**	**683**	**703**	**14 026**	**24 093**
Demand Side Management	60	66	111	105	100	98	77	71	73	77	81	**858**	**1 762**
CEF16 & Demand Side Management Total	**2 995**	**3 099**	**2 786**	**1 924**	**1 708**	**1 376**	**991**	**723**	**732**	**760**	**784**	**14 884**	**25 855**

The CEF16 totals $14 884 million for the ten year period from 2017/18 through 2026/27. Expenditures for MNG&T total $8 134 million, with the balance of $5 892 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements and ongoing efficiency improvements. In addition, DSM expenditures total $858 million for the same period.

MNG&T expenditures total $10 491 million over the twenty year forecast 2016/17 through 2035/36. Business Operations capital totals $13 602 million over the same period. The twenty year forecast includes projected expenditures for 2016/17 as well as forecast requirements to 2035/36. Over the latter ten years of the forecast period increases for Business Operations capital have been incorporated in order to address expected aging infrastructure requirements

DSM expenditures total $1 762 million over the twenty year forecast. The increase within the twenty year forecast reflects continued investment in both Electric and Natural Gas DSM programs.

REFERENCE:

PUB MFR 72 Attachment Page 45 of 615

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide the revenue requirement impacts for each of the years 2018/19 through to 2035/36 assuming a reduction in Business Operations Capital spending of $100 million in each and every year.

RATIONALE FOR QUESTION:

RESPONSE:

The revenue requirement impacts of the reduction in Business Operations Capital spending of $100 million each year between 2018/19 to 2035/36, have been provided in the financial statements below, which show the difference between this scenario and MH16 Update with Interim.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Capital Spending Down $100M/year less MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
REVENUES										
General Consumers										
at approved rates	0	0	(0)	(0)	0	(0)	0	0	0	0
additional*	0	(0)	0	(0)	(0)	(0)	0	0	0	0
BPIII Reserve Account	0	0	(0)	0	0	0	0	(0)	0	0
Extraprovincial	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Other	0	(0)	0	0	0	0	0	0	0	0
	0	0	(0)	(0)	0	(0)	0	0	0	0
EXPENSES										
Operating and Administrative	0	0	0	0	(0)	0	0	0	(0)	0
Finance Expense	0	(0)	(1)	(4)	(9)	(12)	(19)	(17)	(17)	(17)
Finance Income	0	0	0	(0)	(0)	(2)	(1)	(6)	(10)	(14)
Depreciation and Amortization	0	0	(1)	(4)	(8)	(11)	(15)	(19)	(22)	(26)
Water Rentals and Assessments	0	(0)	(0)	(0)	(0)	0	0	(0)	0	0
Fuel and Power Purchased	0	0	0	0	(0)	0	(0)	(0)	0	(0)
Capital and Other Taxes	0	0	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(3)
Other Expenses	0	0	0	0	(0)	0	(0)	(0)	(0)	(0)
Corporate Allocation	0	0	0	0	0	0	0	0	0	0
	0	0	(2)	(9)	(18)	(27)	(38)	(44)	(52)	(60)
Net Income before Net Movement in Reg. Deferral	0	(0)	2	9	18	27	38	44	52	60
Net Movement in Regulatory Deferral	0	0	0	0	0	0	0	0	0	0
Non-recurring Gain	0									
Net Income	0	(0)	2	9	18	27	38	44	52	60
Net Income Attributable to:										
Manitoba Hydro	**0**	**0**	**2**	**9**	**18**	**27**	**38**	**44**	**52**	**60**
Non-controlling Interest	0	0	0	(0)	0	0	0	(0)	0	0
* Additional General Consumers Revenue										
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Financial Ratios										
Equity	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%
EBITDA Interest Coverage	0.00	(0.00)	0.00	0.01	0.02	0.03	0.04	0.05	0.06	0.07
Capital Coverage	0.00	0.00	0.35	0.37	0.48	0.63	0.58	0.59	0.51	0.47

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Capital Spending Down $100M/year less MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES										
General Consumers										
at approved rates	0	0	0	(0)	0	0	(0)	0	(0)	0
additional*	0	(0)	0	0	0	(0)	0	0	0	(0)
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	(0)	(0)	(0)	0	(0)	0	0	(0)	(0)	0
Other	(0)	0	(0)	(0)	0	0	0	(0)	0	(0)
	0	(0)	0	(0)	0	0	0	0	0	0
EXPENSES										
Operating and Administrative	0	0	0	(0)	0	(0)	(0)	0	(0)	0
Finance Expense	(36)	(49)	(48)	(47)	(78)	(91)	(105)	(118)	(123)	(123)
Finance Income	(5)	(5)	(10)	(15)	0	(1)	(0)	0	(5)	(12)
Depreciation and Amortization	(29)	(33)	(36)	(40)	(43)	(47)	(50)	(54)	(57)	(61)
Water Rentals and Assessments	(0)	0	(0)	(0)	(0)	0	(0)	0	(0)	(0)
Fuel and Power Purchased	(0)	0	0	0	0	(0)	(0)	0	(0)	0
Capital and Other Taxes	(4)	(4)	(4)	(4)	(5)	(5)	(5)	(6)	(6)	(6)
Other Expenses	(0)	(0)	0	0	(0)	0	(0)	0	0	(0)
Corporate Allocation	0	0	0	0	0	0	0	0	0	0
	(74)	(90)	(98)	(107)	(126)	(145)	(161)	(177)	(191)	(201)
Net Income before Net Movement in Reg. Deferral	74	90	98	107	126	145	161	177	191	201
Net Movement in Regulatory Deferral	0	0	0	0	0	0	0	0	0	0
Non-recurring Gain										
Net Income	74	90	98	107	126	145	161	177	191	201
Net Income Attributable to:										
Manitoba Hydro	**74**	**90**	**98**	**107**	**126**	**145**	**161**	**177**	**191**	**201**
Non-controlling Interest	0	0	(0)	(0)	(0)	(0)	0	(0)	(0)	0
* Additional General Consumers Revenue										
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Financial Ratios										
Equity	2%	2%	3%	3%	4%	5%	6%	7%	8%	9%
EBITDA Interest Coverage	0.10	0.14	0.17	0.21	0.30	0.43	0.58	0.82	1.17	1.64
Capital Coverage	0.48	0.52	0.52	0.57	0.54	0.62	0.64	0.68	0.61	0.62

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Capital Spending Down $100M/year less MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
ASSETS										
Plant in Service	0	0	(100)	(200)	(300)	(400)	(500)	(600)	(700)	(800)
Accumulated Depreciation	0	(0)	1	5	13	25	40	58	80	106
Net Plant in Service	-	0	(99)	(195)	(287)	(375)	(460)	(542)	(620)	(694)
Construction in Progress	0	(0)	(0)	0	0	(0)	0	0	0	0
Current and Other Assets	0	0	(101)	6	115	30	152	277	407	541
Goodwill and Intangible Assets	0	0	0	0	(0)	0	(0)	(0)	(0)	(0)
Total Assets before Regulatory Deferral	0	(0)	(200)	(188)	(172)	(345)	(309)	(264)	(213)	(153)
Regulatory Deferral Balance	0	0	0	0	(0)	(0)	(0)	(0)	0	0
	-	(0)	(200)	(188)	(172)	(345)	(309)	(264)	(213)	(153)
LIABILITIES AND EQUITY										
Long-Term Debt	0	(0)	(200)	(200)	(200)	(400)	(394)	(388)	(388)	(388)
Current and Other Liabilities	0	0	(2)	0	(2)	(2)	(3)	(3)	(3)	(3)
Provisions	0	0	0	0	0	0	0	0	0	0
Deferred Revenue	0	0	0	0	0	0	0	0	0	0
BPIII Reserve Account	0	(0)	(0)	(0)	0	0	(0)	(0)	(0)	(0)
Retained Earnings	0	(0)	2	11	30	57	94	139	191	250
Accumulated Other Comprehensive Income	0	0	0	0	0	0	(6)	(12)	(12)	(12)
Total Liabilities and Equity before Regulatory Deferral	0	0	(200)	(188)	(172)	(345)	(309)	(264)	(213)	(153)
Regulatory Deferral Balance	0	0	0	0	0	0	0	0	0	0
	-	0	(200)	(188)	(172)	(345)	(309)	(264)	(213)	(153)

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Capital Spending Down $100M/year less MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS										
Plant in Service	(900)	(1 000)	(1 100)	(1 200)	(1 300)	(1 400)	(1 500)	(1 600)	(1 700)	(1 800)
Accumulated Depreciation	135	168	204	244	287	334	384	438	495	556
Net Plant in Service	(765)	(832)	(896)	(956)	(1 013)	(1 066)	(1 116)	(1 162)	(1 205)	(1 244)
Construction in Progress	0	0	0	0	0	0	0	0	0	0
Current and Other Assets	79	237	399	566	136	135	(62)	(51)	184	424
Goodwill and Intangible Assets	0	(0)	0	0	0	0	0	0	0	0
Total Assets before Regulatory Deferral	(686)	(596)	(497)	(391)	(878)	(932)	(1 178)	(1 213)	(1 021)	(820)
Regulatory Deferral Balance	(0)	(0)	0	0	0	0	0	0	0	0
	(686)	(596)	(497)	(391)	(878)	(932)	(1 178)	(1 213)	(1 021)	(820)
LIABILITIES AND EQUITY										
Long-Term Debt	(988)	(988)	(988)	(788)	(1 588)	(1 788)	(2 000)	(2 400)	(2 400)	(2 400)
Current and Other Liabilities	(10)	(10)	(10)	(210)	(23)	(21)	(216)	(28)	(27)	(27)
Provisions	0	0	0	0	0	0	0	0	0	0
Deferred Revenue	0	0	0	0	0	0	0	0	0	0
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	324	414	512	619	745	890	1 050	1 227	1 418	1 619
Accumulated Other Comprehensive Income	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
Total Liabilities and Equity before Regulatory Deferral	(686)	(596)	(497)	(391)	(878)	(932)	(1 178)	(1 213)	(1 021)	(820)
Regulatory Deferral Balance	0	0	0	0	0	0	0	0	0	0
	(686)	(596)	(497)	(391)	(878)	(932)	(1 178)	(1 213)	(1 021)	(820)

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Capital Spending Down $100M/year less MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	**ACTUAL**									
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
OPERATING ACTIVITIES										
Cash Receipts from Customers	0	(0)	0	(0)	(0)	0	0	(0)	0	(0)
Cash Paid to Suppliers and Employees	0	(0)	1	1	1	2	2	3	3	3
Interest Paid	0	0	(1)	6	7	12	17	17	17	17
Interest Received	0	0	(0)	0	0	2	1	6	10	14
	-	(0)	(1)	7	9	16	21	26	30	34
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	0	0	(200)	0	0	(200)	0	0	0	0
Sinking Fund Withdrawals	0	0	0	0	0	0	0	(4)	(4)	(4)
Retirement of Long-Term Debt	0	0	0	0	0	0	0	0	0	0
Other	0	0	(0)	0	0	(0)	0	0	0	0
	-	0	(200)	0	0	(200)	0	(4)	(4)	(4)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	0	0	100	100	100	100	100	100	100	100
Sinking Fund Payment	0	0	0	0	0	0	4	4	4	4
Other	0	0	0	0	0	0	(0)	(0)	(0)	0
	-	0	100	100	100	100	104	104	104	104
Net Increase (Decrease) in Cash	-	0	(101)	107	109	(84)	125	126	130	134
Cash at Beginning of Year	0	0	(0)	(101)	6	115	30	156	281	411
Cash at End of Year	-	0	(101)	6	115	30	156	281	411	545

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Capital Spending Down $100M/year less MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES										
Cash Receipts from Customers	(0)	(0)	(0)	0	0	(0)	0	(0)	(0)	0
Cash Paid to Suppliers and Employees	4	4	4	4	5	5	5	6	6	6
Interest Paid	30	49	49	49	64	92	99	119	126	126
Interest Received	5	5	9	14	0	1	(1)	(2)	2	8
	38	57	62	67	70	99	104	123	135	140
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(600)	0	0	0	(800)	(200)	(400)	(400)	0	0
Sinking Fund Withdrawals	(4)	0	0	0	(47)	0	0	(7)	0	(10)
Retirement of Long-Term Debt	(0)	0	0	0	200	(0)	0	188	0	0
Other	0	0	0	0	0	0	(0)	0	(0)	(0)
	(604)	-	-	-	(647)	(200)	(400)	(220)	0	(10)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	100	100	100	100	100	100	100	100	100	100
Sinking Fund Payment	4	10	10	11	11	16	19	23	26	27
Other	0	(0)	0	(0)	0	0	0	0	(0)	0
	104	110	110	111	111	116	119	123	126	127
Net Increase (Decrease) in Cash	(462)	167	173	178	(466)	15	(177)	27	261	257
Cash at Beginning of Year	545	83	251	423	601	136	151	(26)	1	262
Cash at End of Year	83	251	423	601	136	151	(26)	1	262	519