REFERENCE:

2019/20 Electric Rate Application p. 25

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's original 2019/20 rate application filed on November 30, 2018 requested a 3.5% rate increase that was projected to result in increased revenues of $59 million. The projected financial results for 2019/20 in the original application was a loss of $28 million without the proposed rate increase and a “target” net income of $31 million including the proposed rate increase of 3.5% (Figure 2.9 of the original application).

In the updated application, dated February 14, 2019, the projected financial results for 2019/20 has been revised to a net income of $64 million without the proposed rate increase and a “target” net income of $115 million including the proposed rate increase of 3.5% (Figure 7 of the updated application).

MH’s projected net income without a rate increase has improved by $92 million ($28 million loss to $64 million profit) as a result of the update. The $92 million improvement in net income without a rate increase is $33 million higher than the $59 million annualized rate increase that was sought by MH in the original application.

Despite the above noted improvements in projected operating results for 2019/20, MH has decided not to amend the requested 3.5% rate increase and in reference to the original application states on page 3 of the updated filing at lines 4 to 7 “… having regard for the expedited Application process, Manitoba Hydro determined it would accept the lower projected level of net income in its Application in favour of balancing the interests of ratepayers and their bill impacts”.

QUESTION:

a) Please explain why having regard for an expedited Application process (a regulatory process consideration) should impact the level of targeted net income and proposed rate increases borne by customers (financial and customer impact considerations)?

b) Please explain why a significantly improved financial outlook for 2019/20 in the order of \$92 million would not impact the balancing of the interests of MH's financial position and ratepayer impacts in a manner such that the requested rate increase for consumers would be reduced?

RATIONALE FOR QUESTION:

To obtain further information regarding the underlying rationale for MH's position to maintain the requested 3.5% rate increase when the financial outlook for 2019/20 has substantially improved by \$92 million.

RESPONSE:

a) Based on the water conditions under which the November 30, 2018 Application was filed, a higher level of net income would have provided a greater level of protection to customers to mitigate seeking greater rate relief following a financial loss resulting from low water flows. However, Manitoba Hydro recognized that any rate request in excess of the rate granted in PUB Order 59/18 and the indicative rate increases projected in Manitoba Hydro's forecasts since 2009 would require examination in an extended public proceeding.

b) Although projected financial results have improved since filing the Application, the 3.5% proposed rate increase continues to be necessary and in the public interest and consistent with past decisions and findings of the PUB. As discussed in Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application filed on February 14th 2019, the rate request of 3.5% provides \$50 million of additional revenue allowing for a modest level of net income. Given the variability in earnings the Corporation can experience over a short period of time, the 3.5% rate request reduces the likelihood of a financial loss in 2019/20 should low water flow conditions or other risks materialize. Please see the response to PUB/MH I-29c (Updated) for an analysis of water flow variability and its impact on net export revenues and net income.

Given rate increases provide a compounding benefit, should a rate increase not be awarded in 2019/20, future annual rate increases would need to be higher in order to address the anticipated additional net costs associated with the in-service of Keeyask, MMTP and GNTL.

The following is an illustrative example of the impact to net income once these facilities are placed in-service. The example assumes revenues and expenses at 2019/20 levels plus the additional revenues and costs of Keeyask, MMTP and GNTL as projected in 2022/23. The deficit of approximately $300 million as shown in the table below would require a one-time rate increase of 18% in order to break even.

Without the 3.5% Rate Increase in 2019/20	
Total Revenues (Figure 7)	2,222
KHLP Revenues in 2022/23 (MFR 7 2017/18 & 2018/19 GRA)	262
	2,484
Total Expenses Including Net Movement (Figure 7)	2,162
Revenue Requirment in 2022/23 (PUB/MH I-9U):	
Keeyask	502
MMTP	31
GNTL	97
	2,792
Net Income (Loss)	**(308)**
One-time Rate Increase Required to Breakeven	18%

As an alternative to a one-time 18% rate increase, based on the same revenues and costs as above, rate increases of approximately 5.5% annually would be required in order to achieve break even over a 3 year timeframe with net losses experienced in the first two years.

	Year 1	Year 2	Year 3
Domestic Revenue @ current rates (Figure 7)	1,700	1,700	1,700
Additional Revenue assuming 5.5% annual rate increases	*94*	*192*	*296*
Total Domestic Revenue	1,794	1,892	1,996
Extraprovincial & Other Revenue (Figure 7)	522	522	522
KHLP Revenues in 2022/23 (MFR 7 2017/18 & 2018/19 GRA)	262	262	262
	2,578	2,676	2,780
Total Expenses including Net Movement (Figure 7)	2,162	2,162	2,162
Revenue Requirement in 2022/23 (PUB/MH I-9U)			
Keeyask	502	502	502
MMTP	31	31	31
GNTL	97	97	97
	2,792	2,792	2,792
Net Income (Loss)	(215)	(116)	(12)

Since 2009, Manitoba Hydro's forecasts have projected indicative annual rate increases in the order of 3.5% or more. Exhibit 93, a scenario which was characterized in Order 59/18 as reflective of many of the PUB's decisions, contemplated 18 consecutive years of annual rate increases. In order to maintain the financial results as projected, those rate increases must be implemented each and every year. Otherwise, rate increases in subsequent years, necessarily must be higher to compensate for foregone or reduced rate increases.

The response to PUB/MH I-62b shows that the present value of additional revenues generated over a 17-year period of a 3.5% rate increase granted in 2019/20 is approximately $600 million (2019 dollars at a 6% nominal discount rate). If the PUB declines to approve the requested rate increase, Manitoba Hydro and its customers have approximately $600 million (2019 dollars) in incremental borrowing requirements. Alternatively, the PUB may grant a 3.5% in the following year, but in order to generate approximately the same amount of revenue, a rate increase nearer to 4% would be necessary in 2020/21. As a result, it is Manitoba Hydro's view that a 3.5% rate increase granted in 2019/20 is necessary in order to mitigate the impacts of Keeyask and the associated transmission and the need for even higher future rate increases.

REFERENCE:

2019/20 Electric Rate Application p. 37-43

PREAMBLE TO IR (IF ANY):

On page 5 of Manitoba Hydro's application, it states:

"The 3.5% requested rate increase is aligned with PUB-approved rate increases since 2015 and keeps Manitoba's customer rates and estimated bill impacts among the lowest in North America."

Section 3.0 of Manitoba Hydro's application provides a comparison of Manitoba Hydro's electricity rates to neighbouring jurisdictions. Manitoba Hydro states that "Manitoba continues to maintain an advantage over most North American jurisdictions with respect to the average monthly bills and average prices for all customer classes." (p. 43)

QUESTION:

Please confirm whether Manitoba Hydro has conducted an analysis which is not limited only to customer bills and average prices for residential customers to other jurisdictions, but also examines other relevant factors, such as: average household income, rate of poverty, and energy cost as a proportion of household income or expenditure. If such an analysis has been conducted, please provide it. If not, please explain why.

RATIONALE FOR QUESTION:

Relevant context is necessary to better understand the information provided by Manitoba comparing monthly bills and average prices in North American jurisdictions.

RESPONSE:

Manitoba Hydro has not conducted a neighboring jurisdictional analysis that includes household income, rate of poverty, or energy cost as a proportion of household income or expenditure. The comparison of annual bills of Manitoba Hydro customers with those found in other jurisdictions provides the degree to which customers generally pay less for electricity in Manitoba. Notwithstanding that there are differences in income levels and the overall cost of living between jurisdictions, the relative ranking of the level of electricity costs can be a meaningful indication of the relative value of Manitoba Hydro’s service.

REFERENCE:

PUB-MH I-3a, 2019/20 Electric Rate Application p.1

PREAMBLE TO IR (IF ANY):

In response to PUB-MH I-3a, Manitoba Hydro has identified various general ways that Manitoba Hydro interacts with customers, but has not identified any consultation sessions with ratepayers with respect specifically to the rate increase sought in this application. In its application, Manitoba Hydro has indicated that the the Manitoba Hydro-Electric Board is undertaking a "comprehensive review of Manitoba Hydro's operations, forecasts and financial plans" to "allow the MHEB to establish a long-term financial plan for the Corporation."

QUESTION:

a) Please confirm that no consultation or engagement sessions with Manitoba Hydro customers and stakeholders took place prior to the filing of this application, specifically relating to the rate increase and issues contained within the 2019/20 rate application. If this is confirmed, please explain why not.

RATIONALE FOR QUESTION:

To confirm whether consultation has taken place or is planned relating to the 2019/20 rate application and the next comprehensive General Rate Application.

RESPONSE:

While Manitoba Hydro has not undertaken a formal public engagement process with respect to its 2019/20 Electric Rate Application, information is communicated through a number of forums to help customers understand the rationale for the requested rate increase. Manitoba Hydro is planning to broadly communicate the requested rate increase to customers using social media posts, an insert in all April 2019 bills and a related webpage on the corporation's external website. Electricity Rates will also be one of the topics customers can discuss with Manitoba Hydro at upcoming public meetings scheduled for Steinbach, The Pas and Winnipeg in March 2019.

Manitoba Hydro also notes that through the Public Utilities Board Hearing Process, interested presenters or intervenors can participate in the review process, and provide feedback on the requested rate increase.

REFERENCE:

PUB-MH I-3a, 2019/20 Electric Rate Application p.1

PREAMBLE TO IR (IF ANY):

In response to PUB-MH I-3a, Manitoba Hydro has identified various general ways that Manitoba Hydro interacts with customers, but has not identified any consultation sessions with ratepayers with respect specifically to the rate increase sought in this application. In its application, Manitoba Hydro has indicated that the the Manitoba Hydro-Electric Board is undertaking a "comprehensive review of Manitoba Hydro's operations, forecasts and financial plans" to "allow the MHEB to establish a long-term financial plan for the Corporation."

QUESTION:

b) Please provide details of any consultation with ratepayers (consumers) and stakeholders (institutions) having taken place or planned as part of Manitoba Hydro-Electric Board's review of Manitoba Hydro's long-term financial plan, including operations, forecasts and financial plans. If no such consultation is planned, please explain why not.

RATIONALE FOR QUESTION:

To confirm whether consultation has taken place or is planned relating to the 2019/20 rate application and the next comprehensive General Rate Application.

RESPONSE:

Please see the response to COALITION/MH I-4c-d

REFERENCE:

Current Application p. 1, PUB/MH I-3 (a) (b) (c)

PREAMBLE TO IR (IF ANY):

In its letter to the PUB of August 15, 2018, MH acknowledged that it was in a position to submit a GRA notwithstanding any clear guidance from the PUB on reserve maintenance or any other financial metrics that the PUB will consider in rate-setting (last paragraph page 2). On page 1 of the current application, MH indicates that with the appointment of a new MHEB (in March and June of 2018 per MH's letter to PUB of November 12, 2018), a comprehensive review of MH's operations, forecasts and financial plans is currently being undertaken to allow the MH to establish a long-term financial plan. Upon the MHEB's development and approval of a long-term financial plan, MH will submit a full GRA as well as a fulsome review of responses to PUB directives from Order 59/18, which is anticipated to be filed in late 2019.

QUESTION:

a) Please explain the reason for the change in MH's position with respect to its ability to produce/file an IFF/GRA in August of 2018 with the position taken in MH's letter of November 12, 2018 and 2019/20 rate application of November 30, 2018?
b) Please explain why MH has not provided any information with respect to the macro-economic impacts/impacts on vulnerable consumers of the proposed rate increase in accordance with PUB expectations outlined on page 172 of Order 59/81 that in future rate applications, MH is to assess the broader impacts of rate increases beyond only its financial health (response to PUB/MH I-3 (a) (b) (c))?

RATIONALE FOR QUESTION:

To further understand the special circumstances surrounding the 2019/20 rate application and the plans outlined by MH in terms of filing a comprehensive GRA late in 2019. Manitoba Hydro's future plans regarding the MHEB review and its 2020/21 GRA is relevant to the issue of the impact of the increase on consumers.

RESPONSE:

a) The question posed does not accurately characterize Manitoba Hydro's comments in its August 15, 2018 letter. In its August 15th correspondence, Manitoba Hydro indicated that:

"Manitoba Hydro acknowledges it is in a position to submit a GRA notwithstanding any clear guidance from the PUB on reserve maintenance or other any other financial metrics that the PUB will consider in rate-setting. Manitoba Hydro's submission is that it is unavailing and inefficient to do so and that all Parties, including the PUB, should obtain the benefit of the further discussion and dialogue on these important matters enabled by the technical conference."

This was intended to communicate that Manitoba Hydro was not of the opinion that it was precluded from filing a GRA in the absence of a PUB finding on financial metrics, although it acknowledged that such a filing would result in parties revisiting a number of the issues canvassed in the 2017/18 and 2018/19 GRA. These comments were not intended to imply that Manitoba Hydro was, in August 2018, in a position to file a GRA at that time. While the PUB no longer plans to hold a technical conference on financial targets, as noted in subsequent correspondence and in the current Application, the new MHEB must establish the long-term financial plan and targets for the Corporation prior to preparation of the next Integrated Financial Forecast. This IFF, when approved, will form the basis for the next General Rate Application.

The current Electric Rate Application is intended to ensure that the financial stability of the Corporation does not deteriorate further prior to completion of this exercise and preparation of the related long-term forecasts. While Keeyask final costs and other planning assumptions are uncertain at this time, what is known is that when Keeyask comes into service it will require over $300 million in net carrying costs, which revenues at current approved PUB rates are not sufficient to cover (see the response to COALITION/MH I-1). A 3.5% rate increase effective June 1, 2019 will serve to mitigate the risk that the utility and its stakeholders be required to impose significant rate increases on consumers in future years.

b) The response to PUB/MH I-3 provides details of the consultations and customer communications Manitoba Hydro has engaged in as well as information related to customer satisfaction with all aspects of electrical service. With respect to the macro-economic impacts of the proposed rate increase, Manitoba Hydro has previously advised the PUB and interested parties that an assessment of macroeconomic impacts of utility rate increases on the Province requires consideration of the behavior and performance of the economy of Manitoba as a whole. This is not information which Manitoba Hydro possesses or studies, nor is it in a position to provide same. This type of information has not been filed in previous GRA's and has not historically been considered by the PUB in establishing rates. The assessment or consideration of any macroeconomic impacts of a proposed rate increase on the Provincial economy goes far beyond the balancing of interests of ratepayers and the utility and into the realm of government. Such an assessment is not contemplated either in the *Manitoba Hydro Act (s. 39)* or the *Crown Corporations Governance and Accountability Act (s. 25(4))* as a factor to be considered in establishing just and reasonable rates for utility service.

REFERENCE:

Current Application p. 1, PUB/MH I-3 (a) (b) (c)

PREAMBLE TO IR (IF ANY):

In its letter to the PUB of August 15, 2018, MH acknowledged that it was in a position to submit a GRA notwithstanding any clear guidance from the PUB on reserve maintenance or any other financial metrics that the PUB will consider in rate-setting (last paragraph page 2). On page 1 of the current application, MH indicates that with the appointment of a new MHEB (in March and June of 2018 per MH's letter to PUB of November 12, 2018), a comprehensive review of MH's operations, forecasts and financial plans is currently being undertaken to allow the MH to establish a long-term financial plan. Upon the MHEB's development and approval of a long-term financial plan, MH will submit a full GRA as well as a fulsome review of responses to PUB directives from Order 59/18, which is anticipated to be filed in late 2019.

QUESTION:

c) Please provide details of the MHEB comprehensive review of MH including (i) scope of review/terms of reference (ii) expected deliverables (including any reports that will be filed with the PUB) (iii) timing of completion of expected deliverables.
d) Please provide current details of the steps/timelines to produce an updated IFF and a comprehensive Electric GRA with response to PUB directives from Order 59/18? Please indicate if MH has yet determined the proposed implementation date for a 2020/21 rate change.

RATIONALE FOR QUESTION:

To further understand the special circumstances surrounding the 2019/20 rate application and the plans outlined by MH in terms of filing a comprehensive GRA late in 2019. Manitoba Hydro's future plans regarding the MHEB review and its 2020/21 GRA is relevant to the issue of the impact of the increase on consumers.

RESPONSE:

c) and d)

Manitoba Hydro is in the process of initiating the development of a 20 year Corporate Strategic Plan ("CSP") which will include consultation with all of our key stakeholders. The scope of review/terms of reference is under development.

A 20 year Corporate Strategic Plan is required to set the direction of Manitoba Hydro going forward and will underpin the development of the Corporation's long term financial plan and rate strategy. As this is a new undertaking, Manitoba Hydro needs to ensure it is comprehensive. This process will be the Corporation's focus over the next fiscal year and will form the basis for Manitoba Hydro's next rate application.

Manitoba Hydro anticipates the process will begin in the Spring of 2019 and the intent is to complete the CSP within the 2019/20 fiscal year. As such Manitoba Hydro has not yet determined a proposed implementation date for a 2020/21 rate change.

REFERENCE:

Current Application p.1, PUB/MH I 62 (b)

PREAMBLE TO IR (IF ANY):

In the response to PUB/MH 1-62 (b), MH provides a calculation of the net present value of the proposed annualized rate increase to 2036 utilizing its Weighted Average Cost of Capital.

QUESTION:

Please provide the present value of the (i) total proposed annualized rate increase of $59 million and (ii) annualized rate increase proposed for residential customers of $25 million – in perpetuity using an assumed nominal social discount rate of 5%?

RESPONSE:

i) Based on the Supplement to the 2019/20 Electric Rate Application and a June 1, 2019 implementation, the 3.5% increase is now expected to provide approximately $50 million in revenue for the 2019/20 Year.

   Given the uncertainty of Efficiency Manitoba's DSM Savings levels, the present value in perpetuity was calculated using a 0% growth rate and a 1% 18 year average growth rate. The present value of the proposed annualized revenue associated with the proposed rate increase of 3.5% at a 5.00% nominal social discount rate is $1,303 million (0% growth rate) or $1,457 million (1% growth rate).

In Millions of Dollars

	Nominal Social Discount Rate	Discount Factor	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue
2019	5.00%	1.000	0.00%	0.00%	$0	$0
2020	5.00%	1.050	3.50%	2.97%	50	48
2021	5.00%	1.103	0.00%	3.50%	60	54
2022	5.00%	1.158	0.00%	3.50%	59	51
2023	5.00%	1.216	0.00%	3.50%	60	49
2024	5.00%	1.276	0.00%	3.50%	60	47
2025	5.00%	1.340	0.00%	3.50%	61	45
2026	5.00%	1.407	0.00%	3.50%	61	43
2027	5.00%	1.477	0.00%	3.50%	61	42
2028	5.00%	1.551	0.00%	3.50%	62	40
2029	5.00%	1.629	0.00%	3.50%	62	38
2030	5.00%	1.710	0.00%	3.50%	63	37
2031	5.00%	1.796	0.00%	3.50%	63	35
2032	5.00%	1.886	0.00%	3.50%	64	34
2033	5.00%	1.980	0.00%	3.50%	65	33
2034	5.00%	2.079	0.00%	3.50%	66	32
2035	5.00%	2.183	0.00%	3.50%	66	30
2036	5.00%	2.292	0.00%	3.50%	67	29
PV						**$688**

		Additional Domestic Revenue	0% Growth Rate	1% Growth Rate
A		Nominal Social Discount Rate	5.00%	5.00%
B		Growth Rate	0.00%	1.00%
C	= (A-B)/(1+A)	Capitalization Rate	4.76%	3.81%
D	= 1/C	Terminal Value Multiple	21	26
E		Additional Domestic Revenue (in 2036)	$67	$67
F	= D*E	Terminal Value	$1 411	$1 764
G		Discount Factor (in 2036)	2.292	2.292
H	= F/G	Discounted Terminal Value	$616	$770
I		PV Additional Domestic Revenue (to 2036)	$688	$688
J	= H+I	**PV Additional Domestic Revenue in Perpetuity**	**$1 303**	**$1 457**

Note: Numbers may differ due to rounding.

ii) Based on the Supplement to the 2019/20 Electric Rate Application and a June 1, 2019 implementation, the 3.5% increase for residential customers is now expected to provide approximately $21 million in revenue for the 2019/20 Year.

Given the uncertainty of Efficiency Manitoba's DSM Savings levels, the present value of perpetuity was calculated using a 0% growth rate and a 1% 18 year average growth rate. The present value of the proposed annualized revenue associated with the proposed rate increase of 3.5% at a 5.00% nominal social discount rate is $561 million (0% growth rate) or $628 million (1% growth rate).

In Millions of Dollars

	Nominal Social Discount Rate	Discount Factor	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Residential Revenue	Discounted Additional Residential Revenue
2019	5.00%	1.000	0.00%	0.00%	$0	$0
2020	5.00%	1.050	3.50%	2.97%	21	20
2021	5.00%	1.103	0.00%	3.50%	25	23
2022	5.00%	1.158	0.00%	3.50%	25	22
2023	5.00%	1.216	0.00%	3.50%	25	21
2024	5.00%	1.276	0.00%	3.50%	26	20
2025	5.00%	1.340	0.00%	3.50%	26	19
2026	5.00%	1.407	0.00%	3.50%	26	19
2027	5.00%	1.477	0.00%	3.50%	26	18
2028	5.00%	1.551	0.00%	3.50%	26	17
2029	5.00%	1.629	0.00%	3.50%	27	16
2030	5.00%	1.710	0.00%	3.50%	27	16
2031	5.00%	1.796	0.00%	3.50%	27	15
2032	5.00%	1.886	0.00%	3.50%	28	15
2033	5.00%	1.980	0.00%	3.50%	28	14
2034	5.00%	2.079	0.00%	3.50%	28	14
2035	5.00%	2.183	0.00%	3.50%	29	13
2036	5.00%	2.292	0.00%	3.50%	29	13
NPV						**$294**

		Additional Residential Revenue	0% Growth Rate	1% Growth Rate
A		Nominal Social Discount Rate	5.00%	5.00%
B		Growth Rate	0.00%	1.00%
C	= (A-B)/(1+A)	Capitalization Rate	4.76%	3.81%
D	= 1/C	Terminal Value Multiple	21	26
E		Additional Domestic Revenue (in 2036)	$29	$29
F	= D*E	Terminal Value	$612	$765
G		Discount Factor (in 2036)	2.292	2.292
H	= F/G	Discounted Terminal Value	$267	$334
I		PV Additional Domestic Revenue (to 2036)	$294	$294
J	= H+I	**PV Additional Residential Revenue in Perpetuity**	**$561**	**$628**

Note: Numbers may differ due to rounding.

REFERENCE:

Current Application p.22, Additional Information Attachment 5, PUB I-34 b) & c), PUB I-40 b)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an expanded version of Figure 2.7 (Application, page 22) that includes the years 2017/18 through 2019/20 and that also includes the following:
   i. Canada and MH 5 Year Bond Rates
   ii. Canada and MH 10 Year Bond Rates
   iii. Canada and MH 30 Year Bond Rates
   iv. MH 12 Year WATM (also include for Current Application)
   v. MH 20 Year WATM

b) Please provide a revised version of the response to part (a) which, for the years 2018/19 and 2019/20, also includes the values from the updated interest rate forecast provided in response to PUB I-34 b) & c).

c) Please provide a revised response to PUB I-40 b) based on the updated interest rate forecast provided in the response to PUB I-34 b) & c).

d) Based on the various interest rate forecasts provided in the response to PUB I-34 b), what are the highest and lowest 2019/20 values for each of the following:
   i. Canada and MH 5 Year Bond Rates
   ii. Canada and MH 10 Year Bond Rates
   iii. Canada and MH 30 Year Bond Rates
   iv. MH 12 Year WATM
   v. MH 20 Year WATM

RATIONALE FOR QUESTION:

To understand the changes in the interest rate forecasts since the last GRA.

RESPONSE:

a) The following table provides an expanded version of Figure 2.7 for the forecasts underpinning the Application and Exhibit 93 as well as the Winter 2018 forecast provided in PUB I-34 b) and c).

	Application Winter 2017			Exhibit 93 Spring 2017			Winter 2018	
	2017/18	2018/19	2019/20	2017/18	2018/19	2019/20	2018/19	2019/20
MH Short Term Interest Rate	1.05%	1.50%	2.20%	0.55%	0.90%	1.55%	1.55%	2.20%
MH Long Term Interest Rate								
12 Year WATM	2.65%	3.15%	3.65%	2.55%	3.05%	3.45%	3.20%	3.55%
20 Year WATM	3.00%	3.50%	4.00%	3.15%	3.55%	3.90%	3.45%	3.80%
Canada 5 Year Bond Rate	1.85%	2.20%	2.70%	1.35%	1.90%	2.35%	2.30%	2.70%
MH 5 Year Bond Rate	2.30%	2.75%	3.30%	1.95%	2.45%	2.95%	2.95%	3.30%
Canada 10 Year Bond Rate	2.10%	2.45%	2.90%	1.95%	2.45%	2.80%	2.35%	2.80%
MH 10 Year Bond Rate	2.80%	3.25%	3.80%	2.80%	3.30%	3.70%	3.30%	3.70%
Canada 30 year Bond Rate	2.40%	2.80%	3.20%	2.50%	2.85%	3.20%	2.50%	2.90%
MH 30 Year Bond Rate	3.20%	3.70%	4.20%	3.55%	3.85%	4.15%	3.60%	3.90%
U.S. – Cdn Exchange Rate	1.27	1.27	1.26	1.35	1.32	1.29	1.31	1.30

* Not including the 1% Provincial Guarantee Fee

** The 2018/19 rates for the Winter 2018 forecast provided in PUB/MH I-34c are calculated with actual rates to December 2018 and forecasted rates thereafter.

b) Please see the response to part a).

c) In PUB/MH I-40a-b based on the original application, the potential savings were calculated based on forecast debt issuance for the entirety of fiscal 2019 and 2020. Similarly, if Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances and existing debt issued in the Current Outlook year rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Current Outlook and 2019/20 Approved Budget, would be approximately $3 million in fiscal 2019 and $8 million in fiscal 2020 on a cumulative basis. The yield curve has flattened considerably since the Winter 2017 interest rate forecast was prepared, and as a result the potential savings have diminished.

   If Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances beginning in January 2019 rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Current Outlook and 2019/20 Approved Budget, would be approximately $1 million in fiscal 2019 and $4 million in fiscal 2020 on a cumulative basis.

d) The following table shows the highest and lowest 2019/20 fiscal year values from the Spring 2017, Winter 2017, and Winter 2018 forecasts:

	Highest	Lowest
Canada 5 Year Bond Rate	2.70% Winter 2017 & Winter 2018	2.35% Spring 2017
MH 5 Year Bond Rate	3.30% Winter 2017 & Winter 2018	2.95% Spring 2017
Canada 10 Year Bond Rate	2.90% Winter 2017	2.80% Spring 2017 & Winter 2018
MH 10 Year Bond Rate	3.80% Winter 2017	3.70% Spring 2017 & Winter 2018
Canada 30 year Bond Rate	3.20% Spring 2017 & Winter 2017	2.90% Winter 2018
MH 30 Year Bond Rate	4.20% Winter 2017	3.90% Winter 2018
MH Long Term Interest Rate		
12 Year WATM	3.65% Winter 2017	3.45% Spring 2017
20 Year WATM	4.00% Winter 2017	3.80% Winter 2018

REFERENCE:

PUB I-35, PUB I-38 d)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a revised version of the table in PUB I-35 that includes rows setting out for each year and each of the two cases: i) the total debt associated with the gross interest expense, ii) the average weighted cost debt associated with the gross interest and iii) the interest capitalization rate used.
b) For each year, please provide the reasons (e.g., changes in capital spending, changes in cash from operations, change in cash on hand at year end, etc.) for the change in total debt as between the two cases and quantify the impact of each.
c) For each of the years, please quantify the impact of change in the WATM on Finance Expense based on Exhibit 93 and the underlying interest rate forecast.
d) For each of the years, please quantify the impact of the change in interest rates (i.e., from those in Exhibit 93 to those underpinning the Current Outlook) on Finance Expense based on Exhibit 93 and a 20 year WATM.
e) For each of the years, how much of the difference in Finance Expense in PUB I-35 is attributable to the change in hydrology (i.e., hydraulic generation) as between the two cases.

RATIONALE FOR QUESTION:

To understand the change in Finance Expense since the last GRA.

RESPONSE:

a) The following table provides the weighted average debt outstanding and the weighted average interest rate ("WAIR") which are the basis for the gross interest expense, as well as the interest capitalization rate:

MANITOBA HYDRO
Summary of Total Finance Expense
($ thousands CAD)

	Actual 2018	Current Outlook 2019	Approved Budget 2020	MH93 Forecast 2018	MH93 Forecast 2019	MH93 Forecast 2020	Difference 2018	Difference 2019	Difference 2020
Interest on Short & Long Term Debt									
Gross Interest	774	803	856	765	788	842	9	15	15
Provincial Guarantee Fee	154	182	203	154	186	212	(0)	(5)	(10)
Amortization of (Premiums), Discounts, and Transaction Costs	2	4	4	1	1	1	0	3	3
Intercompany Interest Receivable	(15)	(15)	(16)	(15)	(15)	(16)	(0)	0	(0)
Total Interest on Short & Long Term Debt	**914**	**974**	**1,047**	**906**	**961**	**1,039**	**9**	**13**	**8**
Interest Allocated to Construction	**(343)**	**(275)**	**(311)**	**(360)**	**(320)**	**(319)**	**17**	**45**	**8**
Interest Earned on Sinking Fund	(0)	-	-	(1)	(6)	(14)	1	6	14
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	17	29	30	27	28	28	(10)	1	2
Revaluation of Dual Currency Bonds	1	1	1	1	1	1	0	0	(0)
Corporate Allocation	(18)	(18)	(18)	(18)	(18)	(18)	0	-	-
Other Amortization	30	32	30	32	32	31	(2)	0	(1)
Total Finance Expense	**602**	**743**	**779**	**587**	**677**	**749**	**15**	**66**	**30**
Weighted average debt outstanding	18,131	20,454	22,262	18,004	20,779	22,902	127	(326)	(640)
WAIR on gross interest	4.27%	3.93%	3.85%	4.25%	3.79%	3.68%	0.02%	0.14%	0.17%
Interest capitalization rate	5.30%	4.93%	4.82%	5.31%	5.15%	5.14%	0.00%	-0.22%	-0.32%

b) **Fiscal 2018:** The weighted average debt outstanding was higher in fiscal 2018 than in MH Exhibit 93 mainly due to timing differences in issuance. Debt was issued earlier than forecast in order to take advantage of market opportunities for debt greater than 30 years and USD debt issued at rates favourable to domestic, and to secure funds in advance of large cash requirements. These differences account for an increase in gross interest of approximately $6 million in fiscal 2018.

Fiscal 2019: The weighted average debt outstanding is lower in the Current Outlook than in MH Exhibit 93 mainly due to lower capital expenditures in fiscal 2019. This difference results in approximately $12 million less gross interest in the Current Outlook.

Fiscal 2020: The weighted average debt outstanding is lower in the Approved Budget than in MH Exhibit 93 mainly due to the cumulative impact of lower capital expenditures. This difference results in approximately $23 million less gross interest in the Approved Budget.

c) MH Exhibit 93 assumed a 12 year WATM for new debt issuance. The interest rate forecast from Spring 2017 underlying MH Exhibit 93 showed a yield curve which was much steeper than the most recent interest rate forecast from Winter 2018.

Fiscal 2018: Had MH Exhibit 93 utilized a 20 year WATM assumption for new debt issuance, finance expense in fiscal 2018 would have increased approximately $3 million as compared to the forecast using an assumption of 12 years for new debt issuance.

Fiscal 2019: Had MH Exhibit 93 utilized a 20 year WATM assumption for new debt issuance, cumulatively, finance expense in fiscal 2019 would have increased approximately $20 million as compared to the forecast using an assumption of 12 years for new debt issuance.

Fiscal 2020: Had MH Exhibit 93 utilized a 20 year WATM assumption for new debt issuance, cumulatively, finance expense in fiscal 2020 would have increased approximately $34 million as compared to the forecast using an assumption of 12 years for new debt issuance.

d) **Fiscal 2018:** The difference in interest rates and foreign exchange rates between those forecast in MH Exhibit 93 and those actually experienced in 2018 resulted in a negligible impact to finance expense.

   Fiscal 2019: The change in forecast interest rates and foreign exchange rates between MH Exhibit 93 and the Current Outlook resulted in an increase of approximately $7 million to finance expense in fiscal 2019.

   Fiscal 2020: The change in forecast interest rates and foreign exchange rates between MH Exhibit 93 and the Approved Budget resulted in an increase of approximately $4 million to finance expense in fiscal 2020.

e) The following estimated impacts to finance expense due to hydrology are embedded in the gross interest variance due to changes in the weighted average debt outstanding:

   Fiscal 2018: The change in hydraulic generation between MH Exhibit 93 and what was actually experienced resulted in an increase of approximately $0.4 million to finance expense in fiscal 2018.

   Fiscal 2019: The change in hydraulic generation between MH Exhibit 93 and the Current Outlook resulted in an increase of approximately $1.5 million to finance expense in fiscal 2019.

   Fiscal 2020: The change in hydraulic generation between MH Exhibit 93 and the Approved Budget resulted in an increase of approximately $1.4 million to finance expense in fiscal 2020.

REFERENCE:

Appendix 6 p.16, PUB I-41, PUB I-57, PUB I-60

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Is the response to PUB I-41 b) based on an in-service cost for BP III of $5.04 B (per CEF 18) or $4.77 B (per Appendix 7, page 65)?
b) Please provide the impact of the earlier in-service date on the 2018/19 revenue requirement based on the alternative BP III in-service cost.
c) Does this earlier in-service date have any impact on the forecast revenue requirement for 2019/20?

RATIONALE FOR QUESTION:

To understand the impact of changes in BP III's cost and in-service date.

RESPONSE:

a) The response to PUB I-41b is based on an in-service cost for Bipole III of $4,145 million, which was the amount placed in service on July 4, 2018. There were trailing costs after this date, which result in the December 31, 2018 in-service amount of $4,451 million (provided in response to PUB/MH I-41a), and the final expected in-service amount of $4,769 million (with projected costs extending to 2020/21).

b) Please the response to PUB/MH I-41b for the impact in 2018/19 of the earlier in-service.

c) The early in-service date has no impact on the 2019/20 revenue requirement as the costs will be in-service for the full year and as such the revenue requirement includes a full year of finance expense, depreciation expense and amortization of deferred revenue.

REFERENCE:

Appendix 6 p.16, PUB I-41, PUB I-57, PUB I-60

PREAMBLE TO IR (IF ANY):

QUESTION:

d) With respect to PUB I-57, please provide a comparison of the revenue requirement impact of BP III over the five-year period 2018/19 to 2022/23 based on: i) Exhibit 93 from the previous GRA and ii) the Current Outlook based on a BP III capital cost of $4.77 B.

RATIONALE FOR QUESTION:

To understand the impact of changes in BP III's cost and in-service date.

RESPONSE:

The attached tables provide revenue requirement over the five year period from 2018/19 – 2022/23 assuming a $4.77 billion capital cost as reflected in the 2019/20 Approved Budget compared to the $5.04 billion capital cost as reflected in Exhibit 93 based on the MH16 Update forecast. The finance expense component of the revenue requirement included in the first table below (2019/20 Approved Budget and $4.77 billion capital cost) reflects the update to Manitoba Hydro's average cost of debt.

The impact on the revenue requirement is lower in the first few years due to changes in cash flow timing assumptions. Once fully in-service, the difference between the budget of $4.77 billion and Exhibit 93 is slightly lower due to higher amortization of the BPIII reserve account and lower depreciation mainly offset by a higher finance expense due to higher imputed cost of capital rates.

2019/20 Approved Budget

BIPOLE III ($4.77B) & RIEL STATION
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	124	222	227	233	233
OM&A Costs	8	13	13	13	14
Depreciation	70	101	102	103	103
Amortization of BPIII Reserve	(58)	(78)	(78)	(78)	(78)
Capital Tax	22	23	23	23	23
	166	280	287	294	294

Exhibit 93 / MH16 Update with Interim

BIPOLE III ($5.04B) & RIEL STATION
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	117	219	223	225	225
OM&A Costs	8	13	13	13	14
Depreciation	73	107	107	107	107
Amortization of BPIII Reserve	(47)	(71)	(71)	(71)	(71)
Capital Tax	25	25	24	24	24
	176	293	296	299	298

IMPACT ON REVENUE REQUIREMENT
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	7	2	4	8	8
OM&A Costs	-	-	(0)	0	(0)
Depreciation	(3)	(6)	(5)	(4)	(4)
Amortization of BPIII Reserve	(11)	(7)	(7)	(7)	(7)
Capital Tax	(2)	(2)	(1)	(1)	(1)
	(10)	(13)	(9)	(5)	(4)

REFERENCE:

Appendix 6 p.16, PUB I-41, PUB I-57, PUB I-60

PREAMBLE TO IR (IF ANY):

QUESTION:

e) The response to PUB I-57 indicates that the Current Outlook was based on a BP III capital cost of $5.04 B which is consistent with CEF 18 (Appendix 6). However, the response to PUB I-60 shows an overall in-service cost for BP III of $4.777 B which is attributed to CEF 18. Also, the annual capital expenditures on BP III for 2018/19 and 2019/20 set out in CEF 18 don't match those in PUB I-60, which is reportedly based on CEF 18. Please reconcile.

RATIONALE FOR QUESTION:

To understand the impact of changes in BP III's cost and in-service date.

RESPONSE:

As discussed in the response to PUB/MH I-57, the 2018/19 Outlook and 2019/20 Interim Budget included in the November 30th Application was based on a Bipole III total capital cost of $5.04 billion which is consistent with CEF18.

In the response to PUB/MH I-60, the total amount projected to be in-service by the end of the 2018/19 fiscal year was $4.777 billion as it included only amounts in Capital Work In Progress (2017/18 through 2019/20) and excluded $0.258 billion of intangible assets (e.g. easements) as well as land placed in-service prior to 2017/18. The $4.777 + $0.258 billion equate to the $5.04 billion total cost as per CEF18.

Please see the schedule below for the reconciliation between the annual capital expenditures on Bipole III for 2018/19 and 2019/20 set out in CEF18 compared to those provided in the response to PUB/MH I-60:

Bipole III
Annual Capital Expenditures (CEF 18 Total vs. PUB I-60 Response)

(in millions of dollars)	**2018/19**	**2019/20**
CEF 18 Expenditures	663	33
PUB I-60 Response	660	23
Difference	3	10
less CEF 18 Intangible Asset Expenditures	4	10
Difference Due To Rounding	(1)	-

Please refer to the response to MIPUG/MH I-3 for a comparison of the total actuals and forecast expenditures for Bipole III per CEF18 and the updated balances included in the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

17/18 & 18/19 GRA p.27 & Tab 6, PUB I-18, PUB I-25

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to PUB I-25 a), what are reasons for the $3.6 M increase in the 2018/19 depreciation related to Transmission?
b) Please provide a schedule that compares the Gross In Service Plant (i.e., PP&E) broken down by Generation, Transmission, Stations, Distribution and Other and Intangible Assets for: i) 2017/18 Actuals and the current forecast for 2018/19 and 2019/20 and ii) the forecast underpinning the MH16 Update and Exhibit 93 from the last GRA. Please explain any material variances as between the two forecasts.
c) Do the changes in In-Service Plant as between the two forecasts correlate with the changes in depreciation? If not, please explain why not.

RATIONALE FOR QUESTION:

To understand the reasons for the changes in depreciation expense from the last GRA.

RESPONSE:

a) The $3.6 M increase in the 2018/19 depreciation related to Transmission is primarily due to the impact of the earlier in-service of Bipole III. The MH16 Update with Interim forecast assumed Bipole III would be placed in service July 31, 2018 with depreciation starting in August, 2018. The 2018/19 Outlook reflects the actual in-service date for Bipole III of July 4, 2018.

b) Please see the table below for the comparison of gross in-service additions by capital category broken down by Major New Generation & Transmission, Business Operations Capital and Other. Material differences have been explained following the table.

In-Service Addition (in millions of dollars)	Actual	MH16 Update			2019/20 Supplement		2019/20 Supplement Less MH16 Update	
					Current			
		Approved	Forecast	Forecast	Outlook	Approved		
	2017/18	2017/18	2018/19	2019/20	2018/19	2019/20	2018/19	2019/20
Major New Generation & Transmission	$ 84	$ 91	$ 4 877	$ 75	$ 4 282	$ 122	$ (595)	$ 46
Business Operations Capital								
Generation	112	109	104	104	100	117	(4)	14
Transmission	82	182	100	138	218	117	118	(21)
Distribution	323	284	277	306	210	222	(67)	(85)
Corporate Assets	48	58	55	56	42	51	(13)	(5)
Target Adjustment		(45)	(8)	(10)	-	-	8	10
Business Operations Capital Total	$ 565	$ 589	$ 528	$ 595	$ 570	$ 507	$ 42	$ (88)
Other	38	20	20	19	26	36	6	17
	$ 686	$ 701	$ 5 425	$ 689	$ 4 878	$ 665	$ (547)	$ (25)
% Change over MH16 Update							-10%	-4%

The change in in-service projections for Major New Generation & Transmission is primarily due to lower actual in-service costs for the Bipole III Reliability project in 2018/19 and the revised Bipole III cash flow for 2019/20. The revised cash flow incorporates the scheduling of final clean-up costs, decommissioning of temporary construction infrastructure, construction of permanent accommodations and water treatment plant, as well as the anticipated reduction of $270 million from the control budget to $4.77 billion.

The change for Business Operations Capital reflects the revised in-service projections for the investments underlying the 2018/19 Current Outlook and 2019/20 Approved Budget filed in the Supplement to the 2019/20 Electric Rate Application. In MH16 Update, these years were beyond the budget year (2017/18) and did not have detailed portfolio plans. For additional information regarding the timing of investments, please see the response to PUB/MH I-51b-c.

c) The change in expected in-service additions between the two forecasts correlates with the overall change in depreciation. The 2018/19 Current Outlook for depreciation expense is $465 million (page 5 of the Supplement to the 2019/20 Electric Rate Application) which is $6 million lower than the $471 million depreciation in the MH16 Update reflecting the decline in the expected in-service amounts. The 2019/20 Approved Budget for depreciation expense of $505 million (page 8 of the Supplement to the 2019/20 Electric Rate Application) is $10 million lower than the $515 million in the MH16 Update, reflecting the decline in amounts to be placed in-service for both 2018/19 and 2019/20.

REFERENCE:

PUB I-13

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain the $8.1 M increase in External Service and Materials expenditures projected for 2018/19.
b) Please explain the $8.1 M increase in Collection cost in 2017/18.
c) Please explain the $10.6 M increase in Other expenditures projected for 2018/19.

RATIONALE FOR QUESTION:

To understand the year over year changes in O&A costs.

RESPONSE:

a) The increase of $8.1 million in External Services and Materials in 2018/19 as compared to 2017/18 Actual Results is primarily related to consulting and professional fees as discussed in the response to PUB/MH I-18b. Please refer to the table in PUB/MH I-18b for additional details of the expenditure components within External Services and Materials.

b) As discussed in the response to PUB/MH I-24a, the increase of $8.1 million in collection costs in 2017/18 was the result of an assessment of collectability of arrears.

c) The revised response to PUB/MH I-13b corrects 2018/19 Other Expenditures to $9.2 million, which is an increase of $8 million over the 2017/18 actual Other Expenditures of $1.2 million. As discussed in the response to PUB/MH I-13b (Revised), the increase of $8 million is primarily due to funds for transitional business requirements as a result of the voluntary departure program included in the 2018/19 Outlook.

REFERENCE:

17/18 & 18/19 GRA - PUB I-14 a), PUB I-11 a) & b), PUB I-15 a), PUB II-8, Appendix 6.6 p.9, Exhibit 78, and Current Application pg 28-29, PUB I-21 b)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) MH Exhibit 78 sets out how the forecast OM&A costs for 2017/18 and 2018/19 were developed for purposes of the last GRA. Please provide the assumed number of departures by March 31, 2018 and March 31, 2019 for both: i) the MH 16 O&A Target Assumptions and ii) the O&A Target Assumptions – Post VDP.

b) Please provide an updated version of Exhibit 78 that: i) for 2017/18 shows the actual results for the year and ii) for 2018/19 provides an updated forecast based on current assumptions regarding the impact of General Wage Increases, Merit & Progression, the impact of the VDP and the impact of the Supply Chain Initiative.

c) Using a similar methodology to that in Exhibit 78 and actual 2017/18 O&A as the starting point, please derive forecasts for 2018/19 and 2019/20 O&A. In doing so, please confirm that the VDP savings for 2018/19 and 2019/20 include the impact of General Wage Increases, Merit & Progression through to those years.

d) Please provide a schedule that sets out for:
   - 2017/18 –the actual number of departures as of March 31, 2018; the actual 2017/18 OM&A savings due to the VDP, and the 2017/18 O&A savings assuming a full year impact for all VDP departures,
   - 2018/19 – the forecast number of departures as of March 31, 2019; the forecast 2018/19 O&A savings due to the VDP and the 2018/19 O&A savings assuming a full year impact for all departures.
   - 2019/20 – the additional impact in 2019/20 arising from the full year effect of the VDP departures in 2019/20.

e) With respect to PUB I-21 b), is the $92.6 M based on salaries and benefits as of April 1, 2017? If yes, what is the comparable savings based on anticipated salaries and benefits in 2019/20? Please reconcile this value with the response to part (d).

f) The response to PUB II-8 states that the OM&A savings through to March 31, 2019 assumed in the last GRA (MH16 Update) were based on an EFT reduction of 500. However, the current Application (page 28) indicates that a total of 821 employees have been approved under the VDP with the majority departing by March 31, 2018. Please reconcile these two numbers.

g) Please provide a detailed quantitative analysis with explanatory notes that reconciles MH evidence from the 2017/18 and 2018/19 GRA that (i) the VDP will generate annual O&A savings of approximately $70 million (Tab 2, Page 51, lines 29 to 31, Tab 3, Page 10, lines 12 to 16) and (ii) the Supply Chain initiative will generate potential cost savings of $150 million from 2017/18 to 2020/21 with 30% related to operational reductions (Tab 3, Page 10, lines 21 to 25), with the level of projected O&A savings included in the 2019/20 O&A target?

h) Of the 821 employees that departed under the VDP, please provide how many positions have been re-filled by MH as well as the associated annualized cost for 2019/20.

RATIONALE FOR QUESTION:

To understand the impacts of the VDP for rate setting purposes.

RESPONSE:

a) The table below provides the assumed number of departures for 2017/18 and 2018/19 for the MH16 O&A Target assumption and the O&A Target assumption – post VDP as per Exhibit 78.

	MH16 O&A Target Assumptions			**O&A Target Assumptions Post VDP**	
	2017/18	2018/19		2017/18	2018/19
Cumulative Headcount Reductions, as at March 31	235	470		184	554

b) and c)

The table below provides an updated version of Exhibit 78 for the forecast years 2018/19 and 2019/20.

		2018/19		2019/20
2017/18 Actual Results	$	516.9	$	516.9
Target Assumption Additions:				
Impact of General Wage Increases, Merit & Progression		9.0		18.2
Manitoba CPI (Non-labour & benefit components)		3.0		6.0
Operating costs for in-service of Bipole III converters		8.4		12.9
Target Assumption Reductions:				
Impact of labour savings through staffing reductions		(33.5)		(34.3)
Sourcing savings through Supply Chain Initiative		(2.7)		(7.0)
Change in capitalization assumptions		(7.2)		(1.3)
$ to address Restructuring (e.g. re-training, IT technology) & potential benefit impacts		7.3		-
O&A Budget	**$**	**501.2**	**$**	**511.2**

The following assumptions are included in the table above:

- The impact of General Wage increases, Merit and Progression for 2018/19 and 2019/20 is based on staffing levels as of March 31, 2018;
- Manitoba CPI reflects the current forecast of 2.1% for 2018/19 and 2% for 2019/20;
- Operating costs for in-service of Bipole III remains unchanged from previous forecasts;
- Labour savings are based on the salaries of employees who departed the corporation as well as the associated benefit costs;
- Sourcing savings are based on current projections as provided in PUB/MH I-17b with an assumption of 30% allocated to operations, of which 96% is assumed allocated to Electric Operations;
- Change in capitalization assumptions reflects the deployment of staff to capital; and;
- Dollars to address restructuring and potential benefit impacts includes funds set aside for re-training, IT technology changes and changes to benefit costs which may be required following the VDP.

d) The table below provides a summary of the total wage and benefit savings as a result of the VDP as well as the estimated Electric O&A savings for each year based on the number of VDP departures. The full year impact of the VDP departures is reflected in the following year.

MANITOBA HYDRO
VOLUNTARY DEPARTURE PROGRAM SAVINGS
(in millions of dollars)

	Total Employee Departures	Total Wage/Benefit Savings
Voluntary Departure Program (PUB/MH I-21)	821	$ 92.6

	Total Employee Departures	Electric O&A Departures	O&A Savings 2017/18	O&A Savings 2018/19	O&A Savings 2019/20
2017/18	795	458	$ 20.0	$ 52.5	$ 52.5
2018/19	26	15	-	0.9	1.8
2019/20	0	0			
TOTAL	821	473	$ 20.0	$ 53.4	$ 54.3

e) The $92.6 million discussed in PUB/MH I-21b and in part d) above is not based on salaries as at April 1, 2017. The savings were based on the annual salary paid to employees approved under the VDP in 2016/17, as well as associated benefit costs.

Calculating the savings using anticipated salaries and benefits for 2019/20 would not reflect a true savings for the company as these were not a cost incurred by the corporation. The total savings of $54.3 million in part d) above represents the annual O&A savings to the corporation once all employees approved under the VDP have departed.

f) The 821 is the total number of employees accepted under the VDP. As staff may support multiple functions of the business, including capital construction and operations and maintenance, the total reduction and associated savings is not 100% attributable to O&A. As shown in part d) above, the staff reductions attributable to Electric O&A is estimated to be 473 which is comparable to the 500 reduction referenced in the response to PUB/MH II-8 from the 2017/18 and 2018/19 GRA.

g) i. The $70 million of annual O&A savings referenced in the 2017/18 and 2018/19 GRA is comparable to the 2019/20 anticipated O&A savings of approximately $54 million as outlined in response to part d) above. The difference of $16 million is attributable to a change in the O&A savings assumptions. The total savings estimated in the 2017/18 and 2018/19 GRA assumed a 70% impact to O&A, whereas following the VDP, the 2019/20 O&A target reflects an impact closer to 60% based on current experience.

ii. As per Manitoba Hydro's response to COALITION/MH I-107b from the 2017/18 and 2018/19 GRA, the annual sourcing savings was projected to be $45 million in 2019/20 with cumulative total savings of $150 million over the 3-year period from 2017/18 to 2019/20. Tab 3, page 10 of the 2017/18 and 2018/19 GRA indicated that approximately 70% of savings relate to capital purchases and the remaining 30% relate to operational purchases. As such, cumulative O&A savings would equate to approximately $45 million (30% of $150 million).

As per PUB/MH I-17a-b the total cumulative savings to the end of 2017/18 were $22 million plus an additional $24 million to the end of 2019/20. Assuming 30% of the savings relate to operational purchases, this would equate to $14 million of O&A savings. The difference between the $45 million assumed in the 2017/18 and 2018/19 GRA and the $14 million in the 2019/20 O&A target is attributable to the following:

- The savings identified in PUB/MH I-17 are calculated at the contract level whereas a portion of the $45 million were efficiency savings that cannot be quantified. For example, improving supplier relationship management to optimize time spent on employee/supplier interaction.
- As discussed in the response to COALITION/MH I-107a from the 2017/18 and 2019/29 GRA, Manitoba Hydro initially engaged a consultant as part of the Supply Chain Performance Management Program. The corporation has chosen not to renew the engagement and as such, the savings are expected to be realized over a longer period of time.

h) A total of 821 employees will leave the corporation under the VDP by the end of 2018/19. The VDP was open to all employees and as such, departments were impacted differently depending on the number of employees accepted within each department. Following the VDP, the corporation extensively reviewed its organizational structure and functions and as a result of the review, realigned remaining staff to positions where the job duties/responsibilities were deemed most essential. As a result, the impact of the VDP cannot be measured by the number of positions that existed before and after the VDP as suggested in the question.

The impact of the VDP is more accurately reflected in the Corporation's EFT performance. The number of straight-time EFTs to the end of December 2018 was 5,334 compared to 6,206 EFTs (referenced in PUB/MH I-23b) that existed prior to the start of the VDP in 2016/17.

REFERENCE:

Current Application p.1-2, Appendix 3 p.9 & 28 and 17/18 & 18/19 GRA, PUB II-8, PUB I-17

PREAMBLE TO IR (IF ANY):

On page 142 of Order 59/18, the PUB found that at a time of restructuring and transition, there is an opportunity for MH to find further areas to reduce O&A costs. In Recommendation No. 4 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH make efforts to find further areas to reduce O&A costs, both in terms of staff reductions and supply chain management, after the VDP concludes. On page 28 of the current application, MH indicates that the preliminary O&A target for 2019/20 of $511 million (presumably approved by the MHEB in October of 2018) remains consistent with MH16 that was prepared before the 2017/18 & 2018/19 GRA hearing/issuance of Order 59/18 and that the majority of staff departed as a result of the VDP by March of 2018.

QUESTION:

a) With respect to the response to PUB I-17 a), what portions of the Total Annual Realized and Cumulative Savings in each year are related to operating expenses?
b) With respect to the response to PUB I-17 b), please confirm that the values shown are in thousands of dollars.
c) With respect to the response to PUB I-17 b), what portion of the Total Annual Estimated Savings for each year is related to operating expenses?
d) With respect to the response to PUB I-17 b), are the additional savings from the supply chain initiatives forecast for the year 2019/20 reflected in the O&A forecast for 2019/20? If not, why not? If yes, please indicate how they have been incorporated.
e) Please provide a summary schedule that compares actual and forecast electric O&A spending for the five-year period from 2013/14 to 2017/18, indicating which IFF has been used for the forecast amounts.
f) Please explain if MH has prepared a revised outlook for O&A spending for the 2018/19 fiscal year and if so, please provide a summary of the revised outlook compared to the current forecast in the Application.

g) Please explain if it is MH's position that it has little discretion in terms of reducing O&A spending and if so, contrast this position with past fiscal years when MH has underspent its O&A targets?
h) Please explain why MH has not adjusted the O&A target for 2019/20 for further O&A spending reductions based on PUB recommendation 4 from Order 59/18 and the PUB findings from page 142 of Order 59/18 that are noted in the preamble to this information request?
i) Please explain why MH has not reduced O&A spending in 2018/19 and 2019/20 to mitigate the impacts of its concerns with respect to the volatility of operating results and potential for financial losses?

j) Please provide an update to Figure 6.15 – Contracted Wage Settlements – Tab 6, page 23 of the 2017/18 & 2018/19 GRA, for 2019/20. Please also provide the amount of increase for 2018/19 and 2019/20 related to each bargaining unit as well as corporate exempt employees?
k) Please explain/reconcile the MH assumption of 2% inflationary escalation (Page 28 of Application) in O&A for the 2019/20 fiscal year with the Government of Manitoba public-sector wage freeze legislation (Public Services Sustainability Act)?

RATIONALE FOR QUESTION:

To understand MH's position with respect to the PUB recommendation flowing from Order 59/18 to further reduce O&A costs for rate setting purposes.

RESPONSE:

a) As noted in the response to PUB/MH I-17b, the estimated savings relate to commodities/services which Manitoba Hydro purchases annually and which may be used by both operating and capital projects. The savings are calculated and tracked at the contract level. Tab 3, page 10 of the 2017/18 & 2018/19 GRA indicated that approximately 70% of savings relate to capital purchases and the remaining 30% relate to operational purchases.

b) The values shown in the response to PUB/MH I-17b are in thousands of dollars.

c) As outlined in part a) above, it is estimated that 70% of the savings relate to capital purchases and 30% of the savings relate to operational purchases.

d) As discussed in the response to PUB/MH I-17b, estimated savings are calculated at the contract level and the cost reductions will assist Manitoba Hydro in meeting its annual budgets. Please refer to COALITION/MH I-13b&c for a breakdown of the 2019/20 budget which incorporates a projection for sourcing savings.

e) The following table provides a comparison of forecast and actual electric O&A spending for the five-year period from 2013/14 to 2017/18 and includes the associated IFF used for the forecast amounts.

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS
(000's)

Fiscal Year	IFF	Actual	Forecast	Variance	%
CGAAP					
2013/14	IFF13	480.7	484.5	3.8	0.8%
2014/15	IFF14	480.5	485.8	5.3	1.1%
IFRS					
2015/16	IFF15	542.7	541.7	(1.0)	-0.2%
2016/17*	IFF15	535.8	535.4	(0.4)	-0.1%
2017/18	IFF16	516.9	518.3	1.5	0.3%

*Adjusted to reflect the forecast filed in the 2017/18 & 2018/19 General Rate Application

As shown in the above table, Manitoba Hydro's O&A performance has been within 1% of its approved forecast over the last five fiscal years.

f) As shown in Sections 3 and 4 of the Supplement to the 2019/20 Electric Rate Application, the Current Outlook for 2018/19 and the Approved Budget for 2019/20 for Operating & Administrative expenses remain unchanged from the 2018/19 Outlook and 2019/20 Interim Budget in the 2019/20 Electric Rate Application.

g), h) and i)

In establishing the O&A target, Manitoba Hydro considers the appropriate resource requirements in order to maintain reasonable levels of service and manage the operations of the Corporation. Since the implementation of significant staffing reduction initiatives including the Committed Position Reduction and Voluntary Departure Programs, operational staffing levels will be reduced by approximately 28% through to the end of 2019/20. As such, further reductions would have a much higher likelihood of impacting service and reliability levels. In addition, Manitoba Hydro's earnings are highly variable over short periods of time due to unpredictable factors outside of its control, as discussed in Section 3 of the Supplement to the 2019/20 Electric Rate Application. Adjusting budgets for the month to month volatility of earnings would not align with Manitoba Hydro's responsibility to provide for an ongoing safe and reliable supply of electricity to customers. The O&A targets approved by the MHEB for 2018/19 and 2019/20 incorporate the staffing reduction commitments and as such, further reductions to address volatility of earnings would require continuous adjustments to staffing levels (i.e. layoff/rehire) as the majority of O&A expenditures are employee related.

j) The following table provides an update to Figure 6.15 – Contracted Wages Settlements from Tab 6, page 23 of the 2017/18 & 2018/19 GRA:

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%	0.00%	1.00%	2.00%	0.00%	1.00%
January 1, 2019	1.25%	0.75%	1.25%	TBD	0.75%	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.*

*** Corporate Exempt & Manitoba Hydro Professional Engineers Association employees' pay increase in 2019 is effective March 21, 2019.*

Manitoba Hydro has assumed a 0% increase effective January 1, 2019 for IBEW and 0% effective January 1, 2020 for IBEW, Corporate Exempt and Manitoba Hydro Professional Engineers Association which has been incorporated in the 2019/20 Approved Budget.

k) Manitoba Hydro negotiated collective agreements with all four of its bargaining units prior to the introduction of the public-sector wage freeze legislation (which legislation has not yet been proclaimed). However, Manitoba Hydro has been providing general wage increases to the non-unionized Corporate Exempt and MHPEA personnel at a level consistent with the legislation. IBEW's contract was negotiated for the period commencing January 1, 2016, and its term has just expired. Negotiations are now underway and Manitoba Hydro's budget has incorporated a 0% increase.

Manitoba Hydro has incorporated a 2% inflationary escalation rate to cover external cost increases as well as a payroll provision for salary increases. The payroll provision incorporates both the General Wage Increases (GWI) reflecting settlement agreements shown in part j) and a forecast for progression reflecting annual salary increases for employees eligible to progress within their pay grade salary range based on performance.

REFERENCE:

Current Application p. 16-27, 23-24 & Attachment 2, 17/18 & 18/19 GRA Exhibit 93, PUB I-10

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide, for the years 2017/18 through 2019/20, a revised version of PUB I-10c) that compares the Current Application with Exhibit 93 from the last GRA. For each regulatory deferral account, please also indicate (where applicable) under what expense item the cost being transferred to the regulatory deferral account is reported on the Income Statement (e.g., Change in Depreciation Method amounts are reported under Depreciation and Amortization).
b) For each deferral account, please explain any changes (in either annual additions or amortization) as between the response to part (a) and the Current Application as set out in Attachment 2. In particular, please highlight those changes that are due to Exhibit 93 not fully reflecting the Directives in Order 59/18.
c) Please confirm that in the Current Application the forecast for Net Movement reflects all of the Board's Directives with respect to regulatory deferrals and amortizations. If not, which directives are not incorporated and why.

RATIONALE FOR QUESTION:

To understand the changes in Net Movement since the last GRA.

RESPONSE:

a) Please see the following revised schedule of PUB/MH I-10c which provides the additions and amortization of regulatory deferral accounts for the years 2017/18 through 2019/20 per the Supplement to the 2019/20 Electric Rate Application compared to Exhibit 93. The expense item on the Income Statement that the cost is transferred from to the regulatory deferral account is also provided.

(In thousands of dollars)	Manitoba Hydro Supplement to the 2019/20 Electric Rate Application 2017/18 Actual	2018/19 Current Outlook	2019/20 Approved Budget	Manitoba Hydro Exhibit 93 2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2017/18 Difference	2018/19 Difference	2019/20 Difference
Additions to regulatory deferral accounts									
Other Expenses									
Demand side management expenses	63 667	62 539	61 219	57 184	99 404	94 251	6 483	(36 865)	(33 032)
Site restoration costs	1 221	7 355	6 722	2 794	2 703	1 408	(1 573)	4 652	5 314
Regulatory costs	10 136	1 733	5 282	3 664	2 339	1 339	6 472	(606)	3 943
Discontinuance of Conawapa Generating Station	379 204	-	-	-	-	379 758	379 204	-	(379 758)
Depreciation and Amortization									
Change in depreciation method	32 270	38 739	41 776	33 952	39 506	42 869	(1 682)	(767)	(1 093)
Loss on disposal of assets	8 534	2 000	2 000	-	-	-	8 534	2 000	2 000
Operating and Administrative									
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-
Finance Expense									
Affordable Energy Fund	76	-	-	-	-	-	76	-	-
	515 308	**132 566**	**137 199**	**117 794**	**164 152**	**539 825**	**397 514**	**(31 586)**	**(402 626)**
Amortization of regulatory deferral accounts									
Demand side management expenses	(35 773)	(37 341)	(40 195)	(35 742)	(36 662)	(43 202)	(31)	(679)	3 007
Site restoration costs	(3 480)	(3 927)	(4 065)	(4 106)	(3 990)	(3 855)	626	63	(210)
Regulatory costs	(1 520)	(4 321)	(4 493)	(2 942)	(3 665)	(2 884)	1 422	(656)	(1 609)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	-	-	-
Change in depreciation method	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	(2 079)	(2 612)	(3 206)	(1 177)	(3 020)	(3 687)	(902)	408	481
Loss on disposal of assets	-	-	(1 059)	(288)	(577)	(577)	288	577	(482)
Affordable Energy Fund	(197)	(658)	(437)	(449)	(480)	(563)	252	(178)	126
Discontinuance of Conawapa Generating Station	-	(12 627)	(12 627)	-		(11 592)	-	(12 627)	(1 035)
	(43 741)	**(62 178)**	**(66 774)**	**(45 396)**	**(49 086)**	**(67 052)**	**1 655**	**(13 092)**	**278**

b) Please see below for explanations of any significant changes in additions or amortization between the information provided in the Supplement to the 2019/20 Electric Rate Application and Exhibit 93 from the last GRA.

Demand side management

The 2017/18 DSM spending was higher than the forecast due to greater than anticipated take up in commercial lighting and solar technology programs, as well as higher than projected installations of LED roadway lighting. The additions for the 2018/19 Current Outlook are lower than the Exhibit 93 Forecast due to a reduction in planned spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. The additions for the 2019/20 approved budget are lower than the Exhibit 93 forecast reflecting the continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba. Amortization in 2019/20 is lower as a result of the reduced spending in the 2018/19 Current Outlook as amortization of DSM expenditures commences the following fiscal year.

Site restoration

The increase in additions for 2018/19 and 2019/20 is due primarily to increased spending for the 8 Mile Channel & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations.

Regulatory costs

Actual 2017/18 regulatory costs/activities for the 2017/18 and 2018/19 GRA were significantly higher than the initial projection provided in the Exhibit 93 forecast. The 2019/20 Approved budget further anticipates an increase in regulatory costs/activities for upcoming GRA's as compared to those included in the forecast in Exhibit 93.

Conawapa

The 2017/18 additions were higher than Exhibit 93 primarily as a result of the March 31, 2018 transfer of the Conawapa Generating Station development costs from Construction Work in Progress to a regulatory deferral account, for compliance with Directive 19 in PUB Order 59/18. The forecast for Exhibit 93 had assumed this transfer would occur in fiscal 2019/20. The timing of this transfer also impacts the projected difference in amortization for the 2018/19 and 2019/20 years.

Loss on disposal of assets

Losses on the disposal of assets were higher in 2017/18 as the Exhibit 93 forecast did not include a projection for losses. The losses are the result of the retirement of equipment at the Limestone Generating Station and the St. James station, as well as the retirement of street lights replaced with LED bulbs. For the 2018/19 and 2019/20 years the Supplement to the 2019/20 Electric Rate Application includes amounts for losses on terminal retirements. These terminal retirement losses are assumed to be amortized over a period of 20 years commencing in the 2019/20 year, consistent with the assumption in Exhibit 93 which amortizes asset retirement losses incurred prior to 2017/18 over 20 years.

Deferred ineligible overhead

In the Supplement to the 2019/20 Electric Rate Application the amortization of deferred ineligible overhead is over 34 years for compliance with Directive 21 in PUB Order 59/18. The forecast underlying Exhibit 93 assumed an amortization of 30 years for ineligible overhead.

c) It is confirmed that in the Supplement to the 2019/20 Electric Rate Application forecast Net Movement reflects all of the PUB's Directives with respect to regulatory deferrals and amortization.

REFERENCE:

Current Application p. 16

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that sets out the forecast DSM spending, actual DSM spending and annual additions to the DSM deferral account for the years 2012/13 through 2016/17 that resulted in the $48.8 M balance as of March 31, 2018. For each year, please indicate the CEF used to source the forecast values.
b) What were the forecast and actual DSM spending for 2017/18?

RATIONALE FOR QUESTION:

To understand past variances from forecast in DSM spending.

RESPONSE:

a) The annual DSM deferral amount is based on the difference between the total DSM projected spending as provided in the respective year's DSM plan and the actual total DSM spending for the year. The actual and the forecast balances in the DSM plan include both DSM expenditures deferred to the DSM programs regulatory account and DSM expenditures charged to operating expense in the year. In calculating the annual DSM deferral amount (i.e. the difference between planned and actual DSM expenditures), the planned expenditures are adjusted for actual net Energy Efficiency Loan interest (paid and received) and escalation (where applicable). Notably, the DSM plan amounts do not include the net interest on Energy Efficiency Loans as this aspect of the program is intended to be on a cost recovery basis only.

   In addition, the balances for calculating the annual DSM deferral will not equate to the forecast amounts reflected in the CEF as the CEF only includes DSM expenditures deferred to the DSM programs regulatory account (i.e. excludes annual DSM expenditures charged to operating expense).

Please see the following schedule which provides the annual additions to the DSM deferral account for the years 2012/13 through 2016/17.

FOR THE YEAR ENDED MARCH 31
(in thousands of dollars)

Fiscal Year	DSM Plan	Forecast	Adjustments	Adjusted DSM Forecast	Actual	Adjusted DSM - Actual DSM Deferral Account
2012/13*	2011 Plan	$ 34.0	0	$ 34.0	$ 26.6	$ (7.4)
2013/14*	2011 Plan	35.0	0	35.0	26.1	(8.9)
2014/15	2014 Plan	52.3	0.6	52.9	33.9	(19.0)
2015/16	2015 Plan	61.6	1.8	63.4	55.1	(8.2)
2016/17	2016 Plan	56.8	-0.2	56.6	51.4	(5.2)
TOTAL		**$ 239.7**		**$ 241.9**	**$ 193.1**	**$ (48.8)**

**Per PUB Order 43/16 the 2012/13 and 2013/14 DSM deferral amounts were to be based on the level of DSM spending as set out in Manitoba Hydro's 2011 DSM Plan.*

b) The forecast and actual DSM spending for 2017/18 is shown below.

FOR THE YEAR ENDED MARCH 31
(in thousands of dollars)

Fiscal Year	DSM Plan	Forecast	Adjustments	Adjusted DSM Forecast	Actual
2017/18	2017 Plan	58.0	0.1	58.1	64.3

REFERENCE:

PUB I-45, 17/18 & 18/19 GRA, PUB MFR 80

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to the response to PUB I-45 a), please provide the actual values used to create the figure provided and include the variance explanation values for 2017/18 (MH 16 Update vs. Actuals).
b) Please breakdown the volume impact variances provided in response to part (a) as between those attributable to changes in hydraulic generation vs. those attributable to changes in domestic sales volumes.
c) Where are impacts of the Transmission outages and the early in-service date for BP III captured?
d) With respect to the impact of US Exchange & Other, how much is due to US Exchange and what is captured under "Other"?
e) The response to PUB MFR 80 from the previous GRA indicates that volume changes can impact prices. Please explain how the price impacts were determined for purposes of responding to PUB I-45 (a) in the current rate application.
f) With respect to the response to PUB I-45 b), what accounts for the material increase in the current Outlook's forecast of unit revenues for 2018/19 and why are they lower in 2019/20?

RATIONALE FOR QUESTION:

To understand the changes in Export Revenues from the previous GRA.

RESPONSE:

a) Please refer to PUB/MH-I-45a (Updated). The graph and supporting data has been updated to include the variance analysis between 2017/18 Actual results, 2018/19 Current Outlook, 2019/20 Approved Budget and MH16 Update.

b) The MB Domestic Load is higher on an actual basis in 2017/18, and in the 2018/19 Current Outlook and 2019/20 Approved Budget by 63 GWh, 377 GWh, and 463 GWh respectively compared to MH16 Update as set out in the table below. The remaining volume differential in net export revenues can be attributed to changes in hydraulic generation, supply from other resources such as wind generation, imports and thermal generation and factors such as transmission losses and outages to generation or transmission facilities.

Provision of the estimated volume impact of these increases in domestic load on net export revenues requires disclosure of opportunity export sales information which is confidential and commercially sensitive. This response is being filed in confidence consistent with the PUB's ruling in its letter of February 5, 2019. The confidential portions have been highlighted, and those portions redacted in the public version of this response.

CHANGE IN MB LOAD	2017/18	2018/19	2019/20	Source	
2017/18 Actual, 2018/19 Current Outlook, 2019/20 Approved Budget	22 573	22 602	22 440	COAL-MH-I-20(d) - Update to Attachment 3	
MH16 Update	22 510	22 224	21 977	PUB MFR 24U - 2017/18 Electric GRA	
Increase in MB Load	63	377	463		
US Opportunity Export Sales to USA ($/MWh)	[redacted]				5c
Total Volume Variance due to Change in MB Load					5c

c) Transmission outages primarily impacted the volume of hydraulic generation; however there may be ancillary impacts to other factors such as the average price MH received for its opportunity exports. Please refer to the response to PUB/MH I-42a-h for more information related to the impact of transmission outages. Please refer to the responses to PUB/MH I-46a and PUB/MH I-46b (Updated) for a discussion on transmission line loss reductions attributable to Bipole III.

d) Please refer to the response to PUB/MH-I-45a (Updated) for the breakdown between US Exchange and Other.

e) The response to PUB MFR 80 from the 2017/18 and 2018/19 GRA was not intended to indicate that volume changes can impact prices (i.e. market clearing prices). The response was intended to indicate that volume changes can impact average unit revenue.

Variances in the volume of energy supply (i.e. changes to flow or resource mix) or energy demand (i.e. changes to domestic demand or firm export commitments) generally result in changes in opportunity sale volumes. Average unit revenue is negatively correlated to the volume of export sales in that increasing volumes of export energy will be sold in periods of decreasing value and vice versa. Hence gradual increases in the Manitoba load result in gradual decreases in export volume, and a slight increase in average unit export revenues, even if the price forecast does not change.

The price volume variance analysis that underpins the response to PUB/MH I-45a and PUB/MH I-45a (Updated) is intended to identify the main drivers of variances between two static forecasts and is calculated differently than what has previously been provided in the response to PUB MFR 80. The price volume variance analysis used in both PUB/MH I-45a (Updated) and part (a) of this response is based on the following:

Volume variance = Δ volume x previously forecasted prices
Price variance = Δ price x current forecasted volumes

Total variance = Volume variance
+ Price variance
+ Other non-volume related variance
+ Foreign exchange variance

f) Please refer to the response to PUB/MH I-45b (Updated) for an update to Figure 3.7 from Tab 3 of the 2017/18 GRA.

The Current Outlook projection of average unit revenues for 2018/19 includes actual results for 9 months of the fiscal year (to December 31, 2018) and forecasted prices for the remaining 3 months of the fiscal year. On an actual basis, Manitoba Hydro experienced lower hydraulic generation in 2018/19, resulting in less volume exported in the lower price off-peak opportunity market relative to previous years and a relatively sharp increase in average unit revenues from 2017/18 to 2018/19. Manitoba Hydro also experienced stronger opportunity prices in the first half of 2018/19, particularly in the Canadian market, which is reflected in the average unit revenue table provided in Attachment 3 of the Additional Information filed on December 11, 2018 and in the updated Attachment 3 provided in COALITION/MH I-20d. Conditions that led to the increase in Canadian prices are not projected to continue in 2019/20; therefore average unit revenues are projected to be lower in 2019/20 than in 2018/19.

REFERENCE:

PUB I-43, Current Application p.23 & Attachment 4, 17/18 & 18/19 GRA p.9 of 10, COALITION I-81

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to the response to PUB I-43, please respond to the same question but with regard to 2017/18.
b) With respect to the responses to part (a) and PUB I-43, what is the incremental revenue in each year (2017/18 through 2019/20) from these additional contracts as compared to if the same volumes had been sold a non-dependable energy (i.e. opportunity sales) as assumed in IFF16?
c) Please confirm whether the incremental revenues from these additional contracts are reflected in the forecasts for 2018/19 and 2019/20 in the Current Application.
d) What are the forecast volumes of unsold dependable energy for 2018/19 and 2019/20 (per page 23, lines 16-17) – based on the contracts identified in IFF16 and the response to PUB I-43?
e) Apart for any incremental revenues associated with the new firm capacity contracts identified in the response to part (a) and PUB I-43, did Manitoba Hydro obtain any incremental revenues in 2017/18 or 2018/19 year-to-date from shorter term sales of surplus dependable energy at premium prices or sales into MISO's capacity market? If yes, what were the incremental revenues for 2017/18 and 2018/19 (year-to-date)?
f) Do the additional firm export contracts identified in the response to PUB I-43 account for the increase in dependable energy associated with 2019/20 contracted exports as between: i) COALITION I-81 (3,410 GWh) and ii) Attachment 4 (3,501 GWh)? If not, what accounts for the difference?

RATIONALE FOR QUESTION:

To understand the basis for the Export Revenue forecast.

RESPONSE:

a) Manitoba Hydro has not sold any firm capacity for 2017/18 which is not included in the referenced capacity chart in IFF16.

b) The incremental revenue associated with the additional capacity contracts is as follows:

2017/18	$0.0M
2018/19	[redacted]
2019/20	[redacted]

3a

c) Confirmed.

d) The forecasts of unsold dependable energy for 2018/19 and 2019/20 are indicated at the System Surplus line 9 on page 3 of Attachment 4 of the Additional Information filed by Manitoba Hydro on December 11, 2018.

e) No additional dependable energy sales have been made for 2017/18 and 2018/19 apart from what was identified in the response to PUB/MH I-43.

f) Yes, the difference between the dependable energy obligations of 3,410 GWh in COALITION/MH I-81 and the 3,501 GWh in Attachment 4 is a result of the additional firm export contracts identified in the response to PUB/MH I-43.

REFERENCE:

Current Application p.23, PUB I-44, Attachment 3, PUB I-45 a)

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has used the 2017 Energy Price Forecast (Fall Update) in the Current Application.

QUESTION:

a) Does Manitoba Hydro have a more recent forecast of export prices than the 2017 Energy Price Forecast (Fall Update)?
b) If the response to part (a) is yes, please describe how this export price forecast differs from that used in the Current Application for the years 2018/19 and 2019/20.
c) If the response to part (a) is yes, was the methodology used to develop this export price forecast the same as that used for the 2017 Energy Price Forecast (Fall Update)? If not, please explain the changes.
d) If the response to part (a) is yes, please update the 2018/19 and 2019/20 forecasts in Figure 2.4, Figure 2.5 and Attachment 3 to reflect the more recent export price forecast.
e) The Application states "The reference electricity export prices from the 2017 Energy Price Forecast (Fall Update) for 2019/20 were approximately 6% to 7% lower than the prices from the 2017 Energy Price Forecast (Spring) assumed in Exhibit 93 and filed in the 2017/18 & 2018/19 GRA". However, the response to PUB I-45 a) states "These reductions in net export revenues in the 2018/19 Outlook are partially offset by higher actual and forecast opportunity prices on average over 2018/19 compared to the forecast prices underpinning MH16 Update". Is it reasonable to now expect the 2019/20 export prices to also be higher than those underpinning the MH16 Update? If not, why not? If yes, what is the expected impact on the 2019/20 export revenues?

RATIONALE FOR QUESTION:

To understand the basis for the Export Revenue forecast

RESPONSE:

a) to c)

The Supplement filed February 14, 2019 utilizes December 2018 short term export price forecasts as compared to the 2017 Energy Price Forecast (Fall Update) utilized in the November 30, 2018 Application. The three forecast months (January 1, 2019 – March 31, 2019) contained in the 2018/19 Current Outlook and all twelve months of the 2019/20 Approved Budget are derived from short term monthly energy price forecasts provided by the same independent price forecasters used in the development of the consensus long-term energy price forecast, as well as the MISO Minnesota Hub Day-Ahead On & Off Peak Futures from the Intercontinental Exchange (ICE).

The use of multiple short-term forecast sources was fully adopted in 2018 and is a change from the practice reviewed by Daymark Energy Advisors during the 2017/18 and 2018/19 GRA. Manitoba Hydro identified in Exhibit MH-83 (p. 35) of the 2017/18 and 2018/19 GRA that:

Manitoba Hydro notes that prior to IFF16, Manitoba Hydro's short term export price forecasts were generally only based on Vendor A's forecast due to the frequency of forecasts from other vendors, however recently other vendor's short term price forecasts have become available at a similar frequency to the original vendor forecast, and have been used in Manitoba Hydro's short term export revenue forecast projections. … For MH16 and later forecasts, MH has been using multiple forecast sources for its short term export market price projections.

Similar to the long term consensus energy price forecast, MH converts short term energy forecast prices provided by vendors (MINN pricing node) to MHEB nodal forecast prices using historical transmission congestion and marginal transmission losses between the MINN and MHEB pricing nodes. The process of translating the MINN price forecast to a MHEB nodal price forecast was also reviewed by Daymark in 2017.

d) Please refer to Appendix 14 filed with the Supplement to the 2019/20 Electric Rate Application for updated Figures 2.4 and 2.5. The updated Average Unit Revenue/Cost

Calculation (Attachment 3 of the Additional Information filed on December 11, 2018) has been provided below.

Portions of this response contain information considered to be confidential and commercially sensitive. This response is being filed in confidence consistent with the PUB's ruling in its letter of February 5, 2019. The confidential portions have been highlighted, and those portions redacted in the public version of this response.

AVERAGE UNIT REVENUE/COST CALCULATION

	VOLUMES (in GW.h)	2018/19	2019/20	
	Demand:			
A	Manitoba Domestic Energy Sales	22602	22440	
B	Domestic energy Losses	3002	3242	
C	Firm Export Sales to Canada (excl. Lake St. Joseph)	[redacted]	[redacted]	3a
D	Opportunity Export Sales to Canada	[redacted]	[redacted]	3a
	Firm & Opportunity Export Sales to Canada (excl. Lake St. Joseph) (C+D)	576	229	
E	Lake St. Joseph	82	92	5c
F	Firm Export Sales to US	[redacted]	[redacted]	5c
G	Opportunity Export Sales to US	[redacted]	[redacted]	
	Firm & Opportunity Export Sales to US (F+G)	5760	6768	
H	Net Transmission Losses	493	743	
	Total Demand Volumes:	**32515**	**33514**	
	Supply:			
I	MH Hydraulic Generation	30992	31695	
J	MH Thermal Generation	15	26	
K	Purchased Energy	1508	1792	
	Total Supply Volumes:	**32515**	**33514**	

	REVENUE/COST (in milions of dollars)	2018/19	2019/20	
	Total Manitoba Domestic Energy Sales:			
L	Manitoba Domestic Energy Sales @ Approved Rates	1 702.516	1 698.897	
M	Additional Domestic Revenue	-	50.354	
	Manitoba Domestic Sales	**1 702.516**	**1 749.251**	
	Extraprovincial Revenue:			
N	Total Firm Export Sales to Canada	[redacted]		3a
O	Total Opportunity Export Sales to Canada			3a
	Total Export Sales to Canada (N+O)	39.826	15.777	
P	Total Firm Export Sales to USA	[redacted]		5c
Q	Total Opportunity Export Sales to USA			5c
	Total Export Sales to USA (P+Q)	380.586	396.965	
R	Other Non-Energy Related Revenues	8.136	2.284	
S	Transmission Credits	3.144	3.182	
	Extraprovincial Revenue	**431.692**	**418.209**	
	Water Rentals & Assessments:			
T	MH Water Rentals	103.599	106.509	
U	Assessments	7.821	7.916	
V	Other Costs	2.613	2.828	
	Water Rentals & Assessments:	**114.033**	**117.253**	
	Fuel & Power Purchased:			
W	MH Thermal Generation	1.307	1.781	
X	Purchased Energy	89.876	92.750	
Y	Other Non-Energy related Costs	14.481	6.406	
Z	Transmission Charges	29.084	25.976	
	Fuel & Power Purchased	**134.748**	**126.913**	

AVERAGE UNIT REVENUE/COST ($/MW.h))	2018/19	2019/20	
Manitoba Domestic Energy Sales @ Approved Rates (L/A)	$ 75.33	$ 75.71	
Additional Domestic Revenue (M/A)	-	2.24	
Total Manitoba Domestic Energy Sales @ meter (L+M)/A	75.33	77.95	
Total Firm Export Sales to Canada (N/C)	[redacted]		3a
Total Opportunity Export Sales to Canada (O/D)			3a
Total Export Sales to Canada (N+O)/(C+D)	69.10	69.03	
Total Firm Export Sales to USA (P/F)	[redacted]		5c
Total Opportunity Export Sales to USA (Q/G)			5c
Total Export Sales to USA (includes Net Trans Credits) (P+Q+S-Z)/(F+G)	61.57	55.29	
Total Export Sales (includes Net Trans Credits) (N+O+P+Q+S-Z)/(C+D+F+G)	$ 62.26	$ 55.73	
MH Hydraulic Generation (Water Rentals) (T/I)	$ 3.34	$ 3.36	
MH Thermal Generation (W/J)	$ 89.55	$ 67.35	
Purchased Energy (Including Assessments) (X+U)/K	$ 64.79	$ 56.16	

e) When the Application stated "The reference electricity export prices from the 2017 Energy Price Forecast (Fall Update) for 2019/20 were approximately 6% to 7% lower than the prices from the 2017 Energy Price Forecast (Spring) assumed in Exhibit 93 and filed in the 2017/18 & 2018/19 GRA", it was referring to the Energy Price Forecast, whereas the graph provided in PUB/MH-I-45a is based on the average unit revenue of all sales (including both firm and opportunity sales). Furthermore, as referenced in the response to COALITION/MH-I-18f, the Current Outlook's projection of average unit revenues for 2018/19 contains several months of actual results which resulted in an increase in the average unit revenues for 2018/19. The conditions that led to this increase in average unit revenues are not projected to continue in 2019/20. The average unit revenues projected for 2019/20 are expected to be lower than those projected for MH16 Update with Interim.

REFERENCE:

Current Application p.7 & Attachment 3 and 17/18 & 18/19 GRA, PUB MFR 24 (Updated)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please reconcile the $437 M in export revenue for 2017/18 shown on page 7 with the 2017/18 export revenues as set out in Attachment 3, page 1.
b) Please explain how, in Attachment 3 (page 1), the average prices for 2016/17 and 2017/18 were derived from the volume and revenue values provided.
c) With respect to Attachment 3, are the historical average prices (page 1) and forecast average prices (page 4) calculated on a same basis. If not, please provide the calculations for 2016/17 and 2017/18 on the same basis as the forecast values for 2018/19 and 2019/20.

RATIONALE FOR QUESTION:

To understand the Export Revenue forecast.

RESPONSE:

a) The export revenues as set out in Attachment 3 relate to capacity and energy sold; they do not include revenues received from other export activities such as Merchant Revenues, Ancillary Services, Auction Revenue Rights, hedging instruments, and the sale of Renewable Energy Certificates. For 2017/18 the total amount of revenue received for these activities was $9.2 million.

b) Average prices are not derived directly from the volume and revenue values provided in Attachment 3 (page 1) as the export markets can adjust hourly prices after the fact multiple times through their resettlement process. In addition, there are “true-ups” that occurs between day-ahead and real time prices.

Manitoba Hydro's calculates the average price of its exports based upon the value on which the transaction was entered into with the market. This approach enables consistent and efficient reporting of historical average energy prices, however, may result in small price differences compared to the price calculation based upon total revenue.

c) Yes, the historical average prices and forecast average unit revenues and costs in PUB MFR 24 (Attachment 3) are calculated in a similar manner. Price calculations exclude revenues that are not associated with energy volumes including the export activities referred to in part a) above.

REFERENCE:

Application p.8, 11, 13 and 20-21, Additional Information Cover Letter, p.4 and Attachment 5, 17/18 & 18/19 GRA Coalition I-49, Exhibit 93

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule setting out the following for: i) the IFF16 Update (i.e., Exhibit 93) and ii) the Current Application for each of the years 2017/18 through 2019/20:
   i. The General Consumers Sales forecast per the relevant Load Forecast (For the IFF16 Update please reconcile with Coalition I-49 and for the Current Application please reconcile with Figure 2.6). Note: For the 2017/18 values associated with the Current Application please provide both the actual and the weather normalized values prior to the impact of DSM.
   ii. The Adjustment made for DSM program impacts along with the reference to the appropriate table in the relevant DSM Plan/Supplemental Report. For the 2017/18 values associated with the Current Application, please provide the actual DSM savings for 2017/18.
   iii. iii. The resulting Load Forecast used to determine General Consumer Revenues in the Exhibit 93 and the Current Application. Note: For the 2017/18 values associated with the Current Application please provide both the actual and the weather normalized values including the impact of DSM.

b) Please provide a schedule that sets out: i) the General Consumer Sales forecast for 2017/18 through 2019/20 per the 2017 Load Forecast – broken down by consumer group (i.e., Residential, General Service and Lighting), ii) the impact of each of the three adjustments made in November 2017 to the 2017 Load Forecast by consumer group for each of the years 2017/18 through 2019/20 (as noted on page 4 of the cover letter to the December 11th Additional Information), iii) the resulting load forecast, by consumer group and iv) the load forecast as used in the Current Application.

c) It is understood from pages 8, 11 and 13 that, in the response to part (b), item (iv) differs from item (iii) in that in the Current Application, 2017/18 is based on actual sales, the forecast for 2018/19 has been further updated to incorporate actual sales through to September 2018 (per Current Application, pages 20-21) and the forecast for 2019/20 has been adjusted to reflect the actual 3.36% rate increase approved for August 1, 2017. Please provide the detailed calculations supporting the adjustments to the 2017 Load Forecast to reflect the actual 3.36% rate increase effective August 1, 2017 (per Application, page 21, lines 19-23) and details of the other adjustments made as between items (iii) and (iv).

d) Based on actual sales since September 2018, are the actual General Consumer Sales volumes for 2018/19 now expected to be higher or lower than those underpinning the 2018/19 Domestic Revenue forecast in the current Application (page 13)? If they are now expected to be different, please provide a revised outlook for 2018/19 General Consumer Sales Volumes and Revenues.

RATIONALE FOR QUESTION:

To assess the reasonableness of the load forecasts underpinning the Current Application.

RESPONSE:

a) The following table summarizes the (i) General Consumers Sales forecast, (ii) DSM program impacts and (iii) the resulting Load Forecast used to determine General Revenues for the MH16 Update and the Supplement to the 2019/20 Electric Rate Application ("Supplement").

	MH16 Update			**2018 Electric Load Forecast (Supplement)**		
	General Consumers Sales Forecast (GWh)	*DSM Program Inputs (GWh)*	*Load Forecast for General Consumer Revenues (GWh)*	*General Consumers Sales Forecast (GWh)*	*DSM Program Inputs (GWh)*	*Load Forecast for General Consumer Revenues (GWh)*
	(i)	*(ii)*	*(iii)*	*(i)*	*(ii)*	*(iii)*
2017/18	22,720	210	22,510	22,573	304	22,573
2018/19	22,727	503	22,224	22,642	250	22,392
2019/20	22,910	933	21,977	22,917	477	22,440

Note: 2017/18 General Consumers Sales Forecast for the 2018 Electric Load Forecast reflects actual sales and therefore the 2017/18 DSM Impacts are imbedded in the actual sales.

General Consumers Sales forecast(s) source reference:
MH16 Update – 2017/18 & 2018/19 GRA, PUB MFR 65 (Update) Attachment 1 (2017 Electric Load Forecast), page 7, Table 5 – General Consumer Sales Energy, "Total Sales" column.

Supplement – The source of the General Consumer Sales forecast is based on the 2018 Electric Load Forecast provided as Appendix 15 of the Supplement to the 2019/20 Electric Rate Application.

DSM Program impacts source reference:
MH16 Update –
(2017/18) – 2017/18 & 2018/19 PUB MFR 61 Attachment 1 (2017/18 Demand Side Management Plan), page 2 (line entitled "Demand Side Management Plan (310 GWh) less Codes, Standards and Regulations (72.2 GWh), less Internal Retrofit Program impacts (2.5 GWh) = 235 GWh at generation or 210 GWh at meter.

(2018/19 & 2019/20) –
Planned savings for 2018/19 and 2019/20 have been updated to reflect the removal of 2016/17 and 2017/18 planned savings noted in 2017/18 & 2018/19 GRA Appendix 7.2 of Tab 7 (2016 Demand Side Management Plan), Appendix A.2 (line entitled "Impacts (at meter)" less Internal Retrofit Program impacts and replaced with planned savings for 2017/18 presented under 2017/18 & 2018/19 PUB MFR 61-Attachment 1 (2017/18 Demand Side Management Plan).

Supplement
(2017/18) – Represents preliminary unevaluated actual savings for 2017/18.

(2018/19 & 2019/20) –
Planned savings for 2018/19 and 2019/20 used in the 2019/20 Electric Rate Application are sourced from planned savings for 2018/19 presented under Appendix 13 (2018/19 Demand Side Management Plan) and preliminary savings projections reflected in the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019.

b) i. Table below shows the forecast of General Consumer Sales for 2017/18 through 2019/20 by consumer group in Exhibit 93.

	2017 Load Forecast		
	General Consumer Sales (GWh)		
	Residential	General Service	Lighting
2017/18	7692	14936	92
2018/19	7770	14865	92
2019/20	7835	14984	92

ii. The following table displays the impact to the 2017/18 to 2019/20 fiscal years of adjustments made in November 2017 by sector to the 2017 Electric Load Forecast. The impacts to the changes in Electric Price and Codes and Standard Forecast are listed below. The reduction in the Top Consumer sector as a result of the cancellation of a large project in the petrol/oil/natural gas section does not impact the General Consumer Sales forecast for the years 2017/18 through 2019/20.

	2017 Fall Update Impact				
	General Consumer Sales (GWh)				
	Residential		General Service		Lighting
	Price Forecast	Codes Update	Price Forecast	Codes Update	
2017/18	0	0	32	0	0
2018/19	1	-4	46	4	0
2019/20	41	-1	83	7	0

iii. Table below shows the forecast of General Consumer Sales for 2017/18 through 2019/20 by consumer group in the 2019/20 Interim Budget filed on November 30, 2018.

	2017 Fall Update		
	General Consumer Sales (GWh)		
	Residential	General Service	Lighting
2017/18	7692	14967	92
2018/19	7767	14914	92
2019/20	7875	15074	92

iv. The following table summarizes the load forecast as used in the Supplement to the 2019/20 Electric Rate Application. Please note that 2017/18 values are displaying actual sales.

	2018 Load Forecast		
	General Consumer Sales (GWh)		
	Residential	General Service	Lighting
2017/18	7636	14849	88
2018/19	7808	14762	72
2019/20	7891	14954	72

c) Incorporating a change in the forecast of an electric price increase in 2017/18 from 7.9% in 2017 Load Forecast to 3.36% in 2017 Fall Update does not impact the coefficients produced by the econometric models as 2016/17 is the last historical year used in each respective model. The forecast models impacted by the change in electric price are: Space Heating Systems in New Dwellings Forecast Model, Residential Overall Average Use Model and GS Mass Market Average Use Models. Changing the electric price results in an expected increase of 41 GWh in residential sector and 83 GWh in the general service sector in 2019/20 fiscal year.

Table below is a breakdown of the load impact by each sector from the forecasting model due to the 3.36% rate adjustment.

	2017 Forecast								
	Residential			GS SmallMed			GS Large		
Year	Ave Use (kWh)	Customers	GWh	Ave Use (kWh)	Customers	GWh	Ave Use (kWh)	Customers	GWh
2017/18	15,712.7	486,318	7,641.4	103,511	67,813	7,019.4	6,471,592	353	2,284.5
2018/19	15,754.4	492,792	7,763.6	103,681	68,333	7,084.8	6,486,303	362	2,349.1
2019/20	15,763.8	499,348	7,871.6	104,224	68,861	7,177.0	6,437,110	372	2,392.5
	2017 Fall Update								
	Residential			GS SmallMed			GS Large		
Year	Ave Use (kWh)	Customers	GWh	Ave Use (kWh)	Customers	GWh	Ave Use (kWh)	Customers	GWh
2017/18	15,713.0	486,318	7,641.5	103,978	67,813	7,051.1	6,471,592	353	2,284.5
2018/19	15,756.2	492,792	7,764.5	104,348	68,333	7,130.4	6,486,303	362	2,349.1
2019/20	15,846.5	499,348	7,912.9	104,893	68,861	7,223.1	6,537,155	372	2,429.6
	Difference								
	Residential			GS SmallMed			GS Large		
Year	Ave Use (kWh)	Customers	GWh	Ave Use (kWh)	Customers	GWh	Ave Use (kWh)	Customers	GWh
2017/18	0	-	0	467	-	32	0	-	0
2018/19	2	-	1	666	-	46	0	-	0
2019/20	83	-	41	669	-	46	100046	-	37

For the adjustments made between items (iii) 2017 Forecast with Adjustments in November 2017 and (iv) 2018 Forecast in part (b), please refer to pages 11 to 14 of the 2018 Electric Load Forecast (Changes between the 2017 and 2018 Forecasts section) filed in Appendix 15 of the Supplement to the 2019/20 Electric Rate Application.

d) The 2018/19 Current Outlook for General Consumers sales revenue of $1,703 million, which includes actuals to December 31, 2018, can be found in Figure 2, page 5 of the Supplement to the 2019/20 Electric Rate Application. The revised 2018/19 General Consumers Sales volume forecast is 22,392 GWh and can be found on page 34 of Appendix 15. Actual consumption to December 31, 2018 increased the current outlook for 2018/19 by 210 GWh to 22,602 GWh.

REFERENCE:

PUB I-48

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the supporting details regarding the calculation of the 43 GWh of additional load at the meter in 2019/20 as result of a 3.6% rate increase effective June 1, 2018 as opposed to a 7.9% rate increase effective April 1, 2018.
b) Does the implementation of a 3.6% rate increase for 2018/19 as opposed to 7.9% impact the forecast General Consumer Sales for 2018/19? If yes, by how much? If not, why not?

RATIONALE FOR QUESTION:

To understand the basis for the Domestic Revenue forecast used in the Current Outlook.

RESPONSE:

a) Manitoba Hydro's econometric models for Residential and General Service Large sectors incorporate a two and a half year and two year lag in the electricity price independent variable respectively, and as a result the implementation of a 3.6% rate increase as opposed to 7.9% for 2018/19 will have no impact on the forecasted volumes in 2019/20 for those two sectors. The General Service Small and Medium econometric model do not incorporate a two year lag. The forecasted volumes for General Service Small and Medium sector with a 3.6% rate increase effective June 1, 2018 are 7,266.4 GWh, and the forecasted volumes with a 7.9% rate increase effective April 1, 2018 are 7,223.1 GWh. Therefore, the total estimated impact to the forecasted volumes is an additional 43.4 GWh in year 2019/20.

b) The estimated impact to the forecasted volumes in 2018/19 as a result of the implementation of a 3.6% rate increase June 1, 2018 rather than a 7.9% rate increase effective April 1, 2018 is an additional 42.9 GWh of load at meter.

REFERENCE:

Current Application p.21, Attachment 4 p.3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Is the difference between the 2019/20 forecast for General Consumer Sales as set out in Figure 2.6 (23,041 GWh) and the forecast in Attachment 4 (26,369 GWh) all attributable to losses between the points of generation and points of customer delivery?
   i. If yes, please provide the basis for the assumed level of losses.
   ii. If no, please explain the difference between the two forecasts and
   iii. In doing so, indicate what “P value” is associated with the load forecast underpinning the Application. (Note: The forecast used in Attachment 4 is indicated to be based on a P50 value (i.e. 50th Percentile)).

b) Please reconcile the 2019/20 Planned DSM Savings of 834 GWh as set out in Figure 2.6 (Application, page 21) with the 766 GWh of DSM savings for 2019/20 set out in Attachment 4 (page 3). If they are based on different “starting points” in time, please indicate how this reflected in response to part (a).

RATIONALE FOR QUESTION:

To understand the load forecast and DSM savings used in the Current Outlook.

RESPONSE:

a) Both numbers represent the same P50 forecast and the difference between the 2019/20 forecast of General Consumer Sales of 23,041 GWh and the forecast of Gross Firm Energy of 26,369 GWh represented in Attachment 4 are distribution losses, construction power, transmission losses, station service and the reduction of diesel and non-firm energy. The following is a breakdown of the components between General

Consumer Sales (at meter) and Gross Firm Energy (at generation) for the 2019/20 fiscal year.

	2019/20	
General Consumers Sales (@ meter)	**23,041**	**GWh**
Less: Diesel Sales	(15)	GWh
Add: Construction Power	75	GWh
Add: Distribution Losses	1,073	GWh
Add: Transmission Losses	2,095	GWh
Less: Interruptible (non-firm energy)	(26)	GWh
Add: Station Service	126	GWh
Gross Firm Energy (@ generation)	**26,369**	**GWh**

b) The 2019/20 Planned DSM Savings of 834 GWh covers the 3-year planning period of 2017/18 to 2019/20 and reports the DSM savings at meter. The 766 GWh of DSM savings for 2019/20 in Attachment 4 covers the 2-year planning period of 2018/19 to 2019/20 and reports the DSM savings at generation. The following table reconciles the two values.

	2019/20	
DSM Savings (@ meter)	**834**	**GWh**
Less: 2017/18 persisting activity	(158)	GWh
Add: Internal Retrofit Program Savings	6	GWh
Add: Transmission Losses	68	GWh
Add: Distribution Losses	15	GWh
DSM Savings (@ generation)	**766**	**GWh**

Totals may not add up due to rounding.

REFERENCE:

Current Application, Appendix 9, PUB I-26 b), PUB I-27 Attachment 3 p.2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm whether, as a result of the updated Appendix 9, hydraulic generation in each of 2018/19 and 2019/20 is expected to be higher or lower than that assumed in the Current Outlook.
b) Please provide an update to Volume data provided in Attachment 3 (page 2) as a result of the update to Appendix 9.

RATIONALE FOR QUESTION:

To understand the rate setting implications of the more recent data now available regarding "energy in storage".

RESPONSE:

a) Hydraulic generation in 2018/19 is expected to be 30,992 GWh and is reflected in the 2018/19 Current Outlook filed with Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application on February 14, 2019. This is a 257 GWh (0.8%) increase over the 2018/19 Outlook filed on November 30, 2018. The 2018/19 Current Outlook is based on actual information contained in Appendix 9 Updated to December 31, 2018.

   The average hydraulic generation underlying the 2019/20 Approved Budget is 31,695 GWh. This is a 1,543 GWh increase compared to the 2019/20 Interim Budget filed on November 30, 2018. The increase is in part due to higher starting storage expected on April 1, 2019 which, as explained above, reflects updated information in Appendix 9 to December 31, 2018. The increase in hydraulic generation is also partly due to greater storage draw through 2019/20, as compared to average storage draw that underlies the 2019/20 Interim Budget. Hydraulic generation in 2019/20 is highly uncertain as it is largely dependent on long range precipitation which is impossible to predict. As a result, average revenues and costs in 2019/20 are derived from simulations using the full record of historic inflows. The downside risk to hydraulic generation is approximately 11.6 TWh (or 35%) relative to the 2019/20 Approved Budget, similar to the downside risk illustrated in Figure 6 in the response to PUB/MH I-29a.

b) Please refer to the updated Attachment 3 (page 2) filed in response to COALITION/MH I-20d which reflects updated information in Appendix 9 up to December 31, 2018.

REFERENCE:

Current Application, Appendix 9, PUB I-26 b), PUB I-27 Attachment 3 p.2

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Will Manitoba Hydro commit to further updating Appendix 9 (for the period up to March 31, 2019) before the start of the Oral Evidentiary Hearing in late April? If not, why not?

RATIONALE FOR QUESTION:

To understand the rate setting implications of the more recent data now available regarding "energy in storage".

RESPONSE:

Please see the link below for the Updated Appendix 9 which includes data up to January 2019.

https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/electric_rate_application_2019/09_appendix_9_-_report_on_hydraulic_generation_water_conditions_and_extraprovincial_energy_exchange_data.pdf

Manitoba Hydro will file an update to Appendix 9 with the PUB prior to commencement of any oral hearing.

With respect to the rational for this question, it is important to recognize that Manitoba Hydro operates in a complex environment with multiple interdependencies, which makes it difficult to deduce rate setting implications by looking at certain updated information in isolation of other factors and without a detailed assessment of their impacts. For example, if considering only that storage has increased relative to average, it would be inappropriate to conclude Manitoba Hydro's revenue requirements will be lower than previously forecast.

Other factors such as changes to the Manitoba load forecast, export market conditions, economic indicators and interest rates can offset the impact of reservoir storage.

With respect to inferring impacts in absence of detailed assessments, it may be that overall system storage is improved relative to average; however the distribution of storage across the system may not be in balance. A condition where some reservoirs are well above average requiring additional spill to manage levels within licence limits (with no additional generation) and other reservoirs are well below average, may be less favourable to hydraulic generation and revenue requirement as compared to a circumstance where reservoir storage is slightly below average, but balanced across the system.

REFERENCE:

Current Application, Appendix 9, PUB I-26 b), PUB I-27 Attachment 3 p.2

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please update the response to PUB I-27 as required to reflect the Appendix 9 update.

RATIONALE FOR QUESTION:

To understand the rate setting implications of the more recent data now available regarding "energy in storage".

RESPONSE:

Please see the response to PUB/MH I-27 Updated.

REFERENCE:

Current Application p.23, 17/18 & 18/19 GRA, MH Exhibit 93 & MH PUB MFR 25

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide a revised version of Exhibit 93 (from the 2017/18 & 2018/19 GRA) (up to 2019/20) where, for the years 2017/18 to 2019/20, the water flows and resulting hydraulic generation reflect the actual values for 2017/18 and the currently forecast values (per part (b)) for 2018/19 and 2019/20.

RATIONALE FOR QUESTION:

To understand the change in assumptions regarding hydraulic generation from the last GRA and the impact on the Current Outlook.

RESPONSE:

MH Exhibit 93 (from the 2017/18 & 2018/19 GRA) has been updated for the 2017/18 actual water flows and the projected hydraulic generation as at December 31, 2018 and is provided below.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH Exhibit 93 - Updated for Dec 31, 2018 Water Flow Conditions
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**
REVENUES				
Domestic Revenue				
at approved rates	1 515	1 578	1 565	1 551
additional*	-	37	110	169
BPIII Reserve Account	(96)	(151)	3	79
Extraprovincial	460	437	432	418
Other	28	30	31	31
	1 907	1 931	2 140	2 249
EXPENSES				
Operating and Administrative	536	518	501	511
Finance Expense	608	588	681	754
Finance Income	(17)	(17)	(21)	(29)
Depreciation and Amortization	375	396	471	515
Water Rentals and Assessments	131	126	114	117
Fuel and Power Purchased	132	130	135	127
Capital and Other Taxes	119	132	145	154
Other Expenses	60	116	109	481
Corporate Allocation	8	8	8	8
	1 952	1 999	2 143	2 640
Net Income before Net Movement in Reg. Deferral	(46)	(67)	(3)	(391)
Net Movement in Regulatory Deferral	66	72	115	473
Non-recurring Gain	20	-	-	-
Net Income	41	5	112	81
Net Income Attributable to:				
Manitoba Hydro before Non-recurring Item	33	13	113	79
Non-recurring Gain	20	-	-	-
Manitoba Hydro	**53**	**13**	**113**	**79**
Non-controlling Interest	(12)	(8)	(1)	2
	41	5	112	81
* Additional Domestic Revenue				
Percent Increase		3.36%	3.57%	3.57%
Cumulative Percent Increase		3.36%	7.05%	10.87%
Financial Ratios				
Equity	16%	14%	14%	13%
EBITDA Interest Coverage	1.51	1.45	1.60	1.59
Capital Coverage	1.53	1.25	1.29	1.22

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH Exhibit 93 - Updated for Dec 31, 2018 Water Flow Conditions
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020
ASSETS				
Plant in Service	13 065	13 679	19 062	19 684
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)
Net Plant in Service	12 093	12 378	17 332	17 506
Construction in Progress	7 079	9 471	6 745	7 522
Current and Other Assets	1 773	1 836	2 290	2 587
Goodwill and Intangible Assets	327	541	782	926
Total Assets before Regulatory Deferral	21 272	24 226	27 148	28 541
Regulatory Deferral Balance	462	534	649	1 121
	21 733	24 760	27 797	29 662
LIABILITIES AND EQUITY				
Long-Term Debt	15 725	18 141	21 576	22 589
Current and Other Liabilities	3 204	3 644	3 048	3 818
Provisions	70	50	49	48
Deferred Revenue	450	465	491	520
BPIII Reserve Account	196	347	344	265
Retained Earnings	2 749	2 762	2 875	2 955
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 711	27 748	29 614
Regulatory Deferral Balance	49	49	49	49
	21 733	24 760	27 797	29 662
Net Debt	15 427	18 552	20 922	22 718
Total Equity	2 856	3 083	3 332	3 465
Equity Ratio	16%	14%	14%	13%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH Exhibit 93 - Updated for Dec 31, 2018 Water Flow Conditions
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**
OPERATING ACTIVITIES				
Cash Receipts from Customers	1 901	2 075	2 126	2 158
Cash Paid to Suppliers and Employees	(555)	(894)	(832)	(846)
Interest Paid	(553)	(531)	(639)	(707)
Interest Received	17	5	11	22
	810	655	667	627
FINANCING ACTIVITIES				
Proceeds from Long-Term Debt	2 166	3 468	3 800	2 360
Sinking Fund Withdrawals	146	0	0	120
Sinking Fund Payment	(146)	(182)	(222)	(260)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)
Other	(5)	(10)	(10)	(11)
	1 841	2 869	2 566	1 861
INVESTING ACTIVITIES				
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)
Other	(35)	(89)	(57)	(46)
	(2 960)	(3 748)	(3 059)	(2 437)
Net Increase (Decrease) in Cash	(309)	(225)	174	50
Cash at Beginning of Year	943	634	409	583
Cash at End of Year	634	409	583	633

REFERENCE:

Current Application p. 29-30, Appendix 6, 17/18 & 18/19 GRA, Coalition II-48 & MH Exhibit 93, PUB I-4, PUB I-41 a), PUB I-57

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that compares the actual/forecast annual electric capital spending for the period 2017/18 through 2019/20 for: i) the IFF16-Update and ii) the Current Application (i.e., CEF-18). Please use the same format and level of detail as in COALITION II-48 a) & b). Please explain any material variances.

b) Please provide a schedule that compares the actual/forecast annual electric capital in-service additions for the period 2017/18 through 2019/20 for each of the following: i) the IFF16-Update and ii) the Current Application (i.e., CEF-18). Please use the same format and level of detail as in COALITION II-48 d) & e), but break down the category "Demand Side Management, Conawapa and Other into the three components and explain what "Other" includes. Please explain any material variances.

c) With respect to the capital expenditures on Major New Generation & Transmission, please provide a schedule that compares the annual actual/forecast spending on each project (per the breakdown in Appendix 6, page 15) for the period 2017/18 through 2019/20 as used in: i) the IFF16-Update (i.e., Exhibit 93) and ii) the Current Application. Please explain any material variances.

d) Please reconcile the following: i) \$2,949 M Additions to Capital for 2017/18 per PUB I-4 a), ii) \$2,610 M Additions to 2017/18 PP&E per Appendix 1, pages 3 & 4, and iii) \$2,924 M Electric Capital Expenditures for 2017/18 per Appendix 3, page 41.

e) With respect to the response to PUB I-4 c), does the total capital spending include capitalized interest?

f) Please confirm that Bipole III is the only Major New Generation & Transmission project with assets being placed in-service over the 2017/18 to 2019/20 period. If not, for each project, please provide a schedule that compares the in-service timing and in-service costs per: i) the IFF16-Update (i.e., Exhibit 93) and ii) the Current Application.

RATIONALE FOR QUESTION:

To understand the change in forecast capital spending since the last GRA.

RESPONSE:

a) The following table provides a comparison of 2017/18 actual spending compared to the MH16 Update forecast by Major New Generation & Transmission, Business Operations Capital and Demand Side Management. Explanations have been provided for material variances.

	Major New Generation & Transmission			Business Operations Capital			Demand Side Management			Total Capital Expenditures		
Fiscal Year *(in millions of dollars)*	MH16 Update	Actual	Variance	MH16 Update	Actual	Variance	MH16 Update	Actual	Variance	MH16 Update	Actual	Variance
2017/18	2 476	2 463	13	526	461	65	57	64	(6)	3 059	2 988	71
Variance as a % of Total			**18%**			**91%**			**-9%**			**100%**

The total variance of $71 million or 2% on a forecast of $3.1 billion is primarily reflected in Business Operations Capital. Please refer to MH/PUB I-52 a) for the Business Operations Capital variance explanations.

The following table provides a comparison of the forecast spending between MH16 Update and the 2018/19 Current Outlook and the 2019/20 Approved Budget as filed in the Supplement to the 2019/20 Electric Rate Application.

	Major New Generation & Transmission			Business Operations Capital			Demand Side Management			Total Capital Expenditures		
Fiscal Year *(in millions of dollars)*	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance
2018/19	1 625	2 126	(501)	478	517	(39)	63	99	(37)	2 165	2 742	(577)
Change as a % of Total			**87%**			**7%**			**6%**			**100%**
2019/20	1 521	1 274	248	478	516	(39)	61	94	(33)	2 060	1 884	176
Change as a % of Total			**141%**			**-22%**			**-19%**			**100%**

The reduction of $577 million in the 2018/19 Current Outlook as compared to the MH16 Update is primarily in Major New Generation & Transmission (“MNG&T”). As discussed in the Supplement to the 2019/20 Electric Rate Application, the Current Outlook reflects revised cash flows for the Keeyask and MMTP projects, as well as lower actual costs incurred to date for the Bipole III project. The control budget for Bipole III is recommended to be reduced by $270 million to $4.77 billion to reflect actual costs incurred to date and anticipated expenditures to project close-out. In addition, investment requirements related to the Gillam Redevelopment and Expansion Project ("GREP") and the Grand Rapids Fish Hatchery Upgrade and Expansion project included in the MH16 Update have been absorbed within the Business Operations Capital portfolio target.

The overall increase of $176 million in the 2019/20 Approved Budget is also primarily within MNG&T. The increase reflects updated cash flows for MMTP for a revised construction start due to delays in receiving regulatory approvals and revised cash flows for Bipole III for the scheduling of final clean-up costs as well as decommissioning of temporary construction infrastructure and construction of permanent accommodations and water treatment plant.

b) The following table provides a comparison of 2017/18 actual in-service additions compared to the MH16 Update forecast by Major New Generation & Transmission, Business Operations Capital, Demand Side Management, Conawapa and Other. Explanations have been provided for material variances.

	Major New Generation & Transmission			**Business Operations Capital**			**Demand Side Management**			**Conawapa**			**Other***			**Total Capital In-Service Additions**		
Fiscal Year *(in millions of dollars)*	**MH16 Update**	**Actual**	**Variance**	**MH16 Update**	**Actual**	**Variance**	**MH16 Update**	**Actual**	**Variance**	**MH16 Update**	**Actual**	**Variance**	**MH16 Update**	**Actual**	**Variance**	**MH16 Update**	**Actual**	**Variance**
2017/18	91	84	8	589	565	24	57	64	(6)	-	379	(379)	27	49	(22)	765	1 141	(376)
Variance as a % of Total			**-2%**			**-6%**			**2%**			**101%**			**6%**			**100%**

***Other includes Mitigation, Electric Regulatory and Site Remediation**

The 2017/18 actual in-service amounts were higher than the MH16 Update primarily as a result of the March 31, 2018 transfer of the Conawapa Generating Station development costs from Construction Work in Progress to a regulatory deferral account as per Directive 19 of Order 59/18. The forecast assumed this transfer would occur in fiscal 2019/20.

The following table provides a comparison of the forecast in-service additions between MH16 Update and the 2018/19 Current Outlook and the 2019/20 Approved Budget as filed in the Supplement to the 2019/20 Electric Rate Application.

Fiscal Year *(in millions of dollars)*	Major New Generation & Transmission			Business Operations Capital			Demand Side Management			Conawapa			Other*			Total Capital In-Service Additions		
	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance	Supplement to the 2019/20 Electric Rate Application	MH16 Update	Variance
2018/19	4 282	4 877	(595)	570	528	42	63	99	(37)	-	-	-	27	26	1	4 942	5 531	(589)
Change as a % of Total			**101%**			**-7%**			**6%**			**0%**			**0%**			**100%**
2019/20	122	75	46	507	595	(88)	61	94	(33)	-	380	(380)	43	21	22	733	1 165	(432)
Change as a % of Total			**-11%**			**20%**			**8%**			**88%**			**-5%**			**100%**

***Other includes Mitigation, Electric Regulatory and Site Remediation**

The material variances between MH16 Update and the Supplement to the 2019/20 Electric Rate Application reflect the reduction of spending related to Bipole III in 2018/19 and the timing of the transfer of Conawapa to a regulatory deferral account.

c) The following table provides a comparison of 2017/18 actual spending compared to the MH16 Update forecast for each MNG&T project shown in Appendix 6 of the current application.

MANITOBA HYDRO CAPITAL SPENDING *(In millions of dollars)*	**MH16 Update Approved 2017/18**	**Actual 2017/18**	**MH16 Update Less Actual 2017/18**
Major New Generation & Transmission			
Keeyask - Generation	1,077	1,244	(167)
Bipole III - Converter Stations	679	600	79
Bipole III - Transmission Line	511	501	10
Bipole III - Collector Lines	36	32	4
Bipole III - Community Development Initiative	3	3	(0)
Bipole III - Reliability	1,229	1,137	93
Manitoba - Minnesota Transmission	87	28	59
Birtle Transmission	4	2	2
Other Major New Generation & Transmission	79	53	26
Total	**$ 2,476**	**$ 2,463**	**$ 13**

The over expenditure in Keeyask – Generation was primarily due to an increase in the General Civil Works contract as a result of lower productivity rates and challenging geotechnical/geological conditions.

The under expenditure in the Bipole III – Reliability project was primarily due to lower than planned Keewatinohk camp operational costs, later than planned construction activities for the Transmission Line, lower material costs for the Collector Lines, unmaterialized risks and revised project close-out costs, while still achieving the required in-service date.

The under expenditure in the Manitoba – Minnesota Transmission Project was due to the regulatory review process extending longer than anticipated, as previously planned spending on materials and construction contracts were based on a planned construction start date of late 2017.

The following table provides a comparison of the forecast spending for the MNG&T projects between MH16 Update and the 2018/19 Current Outlook and the 2019/20 Approved Budget as filed in the Supplement to the 2019/20 Electric Rate Application.

MANITOBA HYDRO CAPITAL SPENDING *(In millions of dollars)*	Supplement to the 2019/20 Electric Rate Application		MH16 Update		Supplement to the 2019/20 Electric Rate Application Less MH16 Update	
	Current Outlook 2018/19	Approved 2019/20	Forecast 2018/19	Forecast 2019/20	2018/19	2019/20
Major New Generation & Transmission						
Keeyask - Generation	1,304	1,119	1,290	1,117	13	2
Bipole III - Converter Stations	171	74	286	8	(115)	66
Bipole III - Transmission Line	64	26	346	9	(281)	17
Bipole III - Collector Lines	6	2	24	-	(18)	2
Bipole III - Community Development Initiative	1	0	1	-	(0)	0
Bipole III - Reliability	242	101	657	17	(415)	84
Manitoba - Minnesota Transmission	77	276	114	83	(37)	193
Birtle Transmission	2	25	2	19	(0)	6
Other Major New Generation & Transmission			62	39	(62)	(39)
Total	**$ 1,625**	**$ 1,521**	**$ 2,126**	**$ 1,274**	**$ (501)**	**$ 248**

The change between MH16 Update and the Supplement to the 2019/20 Electric Rate Application is primarily due to the revised Bipole III cash flows for 2018/19 and 2019/20 which incorporates the scheduling of final clean-up costs, decommissioning of temporary construction infrastructure, construction of permanent accommodations and water treatment plant, as well as the anticipated reduction of $270 million from the control budget to $4.77 billion. In addition, cash flows for the MMTP project have been adjusted to reflect a revised construction start due to delays in receiving regulatory approvals; however the control budget of $453 million remains unchanged.

d) The difference between the $2,949 M Additions to Capital Assets for 2017/18 per PUB/MH I-4a and the $2,610 M Additions to PP&E for 2017/18 per Appendix 1 is the classification of $339 M of capitalized interest as an investing activity rather than an operating activity as requested by the PUB in PUB/MH I-4a.

The difference between the Additions to PP&E per the Cash Flow Statement variations above and the $2,924 M Electric Capital Expenditures per Appendix 3 (page 41) is due to differences in the classification of certain items in either report. See the following reconciliation of major differences between Additions per the Cash Flow Statement and Electric Capital Expenditures.

Reconciliation of Additions to PP&E to Electric Capital Expenditures
(in millions of dollars)

Additions to PP&E per Appendix 1	$2 610
Capitalized interest classified as investing per PUB I-4	339
Additions to property, plant and equipment per PUB I-4	$2 949
Items in cash flow and not in capital expenditure report	43
Items in Electric Capital Expenditures but not cash flow	(68)
Electric Capital Expenditures	**$2 924**

e) Total capital spending as shown in PUB/MH I-4c includes capitalized interest.

f) Bipole III is not the only MNG&T project with assets being placed in-service over the 2017/18 to 2019/20 period. As documented in the response to PUB/MH I-60b, expenditures for the GREP and the Kettle Improvements and Upgrades were classified as MGN&T in 2017/18, but were removed from the schedule in the response to PUB/MH I-60b for comparability purposes. Both these projects and others had in-service projections between 2017/18 and 2019/20. Please see the following schedule for the Major New Generation & Transmission projects with actual amounts placed in-service for 2017/18, as well as the 2018/19 and 2019/20 projected in-service amounts for both the MH16 Update and the Supplement to the 2019/20 Electric Rate Application.

In-Service Addition (in millions of dollars)	Actual 2017/18	MH16 Update Approved 2017/18	MH16 Update Forecast 2018/19	MH16 Update Forecast 2019/20	Supplement to the 2019/20 Electric Rate Application Current Outlook 2018/19	Supplement to the 2019/20 Electric Rate Application Approved Budget 2019/20
Major New Generation & Transmission	**$ 84**	**$ 91**	**$ 4 877**	**$ 75**	**$ 4 282**	**$ 122**
Bipole III - Reliability	33	32	4 801	17	4 275	104
Gillam Redevelopment & Expansion Program	24	13	74	35		
Kettle GS Units 1-4 Stator Replacement	19	21	1	-		
Wuskwatim - Accommodation & Infrastructure	5	11	-	-		
Point du Bois Spillway Replacement	2	-	-	-		
Kelsey Re-runnering	1	7	1	-		
Manitoba-Minnesota Transmisstion Project		7	-	-	7	18
Grand Rapids Fish Hatchery Upgrade & Expansion		-	-	23		

REFERENCE:

Current Application p. 29-30, Appendix 6, 17/18 & 18/19 GRA, Coalition II-48 & MH Exhibit 93, PUB I-4, PUB I-41 a), PUB I-57

PREAMBLE TO IR (IF ANY):

QUESTION:

g) Please confirm that the $4.451 billion in the response to PUB/MH I-41 (a) is the actual cost of Bipole III as at December 31, 2018. If confirmed, please update the revenue requirement calculation for Bipole III and Riel Station in PUB/MH I-57 (page 2) to include the actual Bipole III cost of $4.451 billion.

h) Is the response to PUB I-57 (based on a BP III of $4.77 B) consistent with the actual spending on BP III as set out in PUB I-41 a)? If not, please update the revenue requirement calculation for BP III in PUB I-57 (page 2).

RATIONALE FOR QUESTION:

To understand the change in forecast capital spending since the last GRA.

RESPONSE:

g) and h):

The $4.451 billion in the response to PUB/MH I-41a represents cumulative in-service additions to December 31, 2018. This includes $4.197 billion placed in-service in 2018/19 (up to December 31, 2018) and $0.254 billion placed in-service prior to 2018/19, as shown in the response to MIPUG/MH I-3.

The original response to PUB/MH I-57 provided the estimated carrying and operating costs for Bipole III based on total project costs of $4.769 billion. This amount includes planned cumulative in-service additions of $4.529 billion to the end of 2018/19, as indicated in the response to MIPUG/MH I-3. This is consistent with the actual amounts already placed in-service to December 31, 2018 noted above, plus a total of

$0.078 billion which Manitoba Hydro anticipates placing in-service during the remaining months of the 2018/19 fiscal year.

REFERENCE:

Current Application p.16 & Appendix 6 p. 5, 32 & 36-41, PUB I-52

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule for each Business Operations spending category (per PUB I-52a)) that sets out the annual actual/forecast capital expenditures for the period 2017/18 through 2019/20 for each of the following: i) the IFF16-Update and ii) the Current Application (i.e., CEF-18). Please explain any material variances in 2018/19 or 2019/20.
b) Please provide a schedule for each Business Operations spending category (per PUB I-52 b)) that sets out the annual in-service additions for the period 2017/18 through 2019/20 for each of the following: i) the IFF16-Update and ii) the Current Application (i.e., CEF-18). Please explain any material variances in 2018/19 or 2019/20.

RATIONALE FOR QUESTION:

To understand the changes in Business Operations capital spending and in-service additions since the last GRA.

RESPONSE:

a) The following table summarizes for each category of Business Operations Capital the actual spending for 2017/18 and the 2018/19 and 2019/20 forecasts provided in MH16 Update and the Current Outlook and Approved Forecast as provided in the Supplement to the 2019/20 Electric Rate Application.

Capital Expenditures (in millions of dollars)	Actual 2017/18	MH16 Update Forecast 2017/18	MH16 Update Forecast 2018/19	MH16 Update Forecast 2019/20	2019/20 Supplement Current Outlook 2018/19	2019/20 Supplement Approved Budget 2019/20	2019/20 Supplement Less MH16 Update 2018/19	2019/20 Supplement Less MH16 Update 2019/20
Business Operations Capital								
Generation	89	95	100	110	95	95	(5)	(15)
Transmission	107	132	134	140	110	110	(24)	(30)
Distribution	228	243	235	220	210	221	(25)	1
Corporate Assets	37	55	55	55	63	52	8	(3)
Unallocated Target Adjustment		0	(8)	(10)	-	-	8	10
Business Operations Capital Total	**$ 461**	**$ 526**	**$ 517**	**$ 516**	**$ 478**	**$ 478**	**$ (39)**	**$ (38)**
					% Change over MH16 Update		**-8%**	**-7%**

During the annual capital planning cycle, Manitoba Hydro reviews its capital investment requirements and produces an investment plan referred to as a Capital Expenditure Forecast (“CEF”). As described in Manitoba Hydro’s response to PUB/MH I-53 (Updated), Business Operations Capital (“BOC”) targets are set annually within Manitoba Hydro’s planning cycle as portfolio plans are developed for the coming year and forecasts of investment requirements are updated for the years beyond.

The 2018/19 and 2019/20 year as they appeared in MH16 Update were the years beyond the budget year and therefore did not have detailed portfolio plans. As shown above, in the ongoing assessment of investments needed to ensure the short term operability and long term sustainability of the electric system, the 2018/19 and 2019/20 targets were reduced by $39M and $38M from MH16 Update, respectively.

b) The following table summarizes for each category of Business Operations Capital the actual in-service additions for 2017/18 and the 2018/19 and 2019/20 forecasts provided in MH16 Update and the Current Outlook and Approved Forecast as provided in the Supplement to the 2019/20 Electric Rate Application.

In-Service Addition (in millions of dollars)	Actual 2017/18	MH16 Update Approved 2017/18	MH16 Update Forecast 2018/19	MH16 Update Forecast 2019/20	2019/20 Supplement Current Outlook 2018/19	2019/20 Supplement Approved 2019/20	2019/20 Supplement Less MH16 Update 2018/19	2019/20 Supplement Less MH16 Update 2019/20
Business Operations Capital								
Generation	112	109	104	104	100	117	(4)	14
Transmission	82	182	100	138	218	117	118	(21)
Distribution	323	284	277	306	210	222	(67)	(85)
Corporate Assets	48	58	55	56	42	51	(13)	(5)
Target Adjustment		(45)	(8)	(10)	-	-	8	10
Business Operations Capital Total	**$ 565**	**$ 589**	**$ 528**	**$ 595**	**$ 570**	**$ 507**	**$ 42**	**$ (88)**
					% Change over MH16 Update		**8%**	**-15%**

Please refer to the response to COALITION/MH I-11b for an explanation of material variances.

REFERENCE:

Current Application p.16 & Appendix 6 p. 5, 32 & 36-41, PUB I-52

PREAMBLE TO IR (IF ANY):

QUESTION:

c) The current Application states (page 16, lines 3-4) that the projects identified in the 2018/19 Financial Outlook are projects which are "active". However, in Appendix 6 (page 37-41) a number of the Business Operations capital projects are identified as a "New Project" beginning in 2018/19 (per page 36). For each of the Business Operations capital projects identified on pages 37-41 that has a total project cost in excess of $5 M, is designated as a New Project and where spending starts in 2018/19, please explain why it is necessary of the project to start in 2018/19 as opposed to being deferred for one or two years.

d) Please explain what is meant by the term "active" as it relates to a capital project per MH's Application (page 16, line 4)? Does that mean the project has commenced planning, has commenced contracting or has commenced construction

RATIONALE FOR QUESTION:

To understand the changes in Business Operations capital spending and in-service additions since the last GRA.

RESPONSE:

c) Investments are advanced to execution to mitigate unacceptable risks to the short term operability and/or long term sustainability of the electric system. To help understand the particular risks being mitigated, Manitoba Hydro has incorporated the use of investment categories in the CEF. Investment categories are commonly used within the industry to provide stakeholders with a better understanding of the primary driver for the investments. The primary investment categories (level 1) are Capacity & Growth, Sustainment, and Business Operations Support. Capacity & Growth investments provide for future load growth or address existing capacity constraints in various geographic areas on the transmission and distribution system.

Sustainment investments are required to ensure the continued and future performance capability of the system and address the issue of aging or obsolete assets. Business Operations Support investments support corporate operations including corporate facilities, information technology, and fleet investments. Detailed investment category definitions are included in Appendix I of the CEF.

The new projects listed in CEF18 (Appendix 6 of the Electric Rate Application) are categorized in the CEF document according to:

- System (Generating, Transmission, Distribution or Corporate Infrastructure)
- Two levels of investment category, as defined in Appendix I of CEF18; and
- Project description.

As explained in Manitoba Hydro's response to PUB/MH I-51b-c, the timing of investment is a complex risk decision with significant potential operational and cost consequences. Manitoba Hydro considers the timing of investment execution as part of its annual capital planning process, based on the best information available at the time, and adjustments are made as new information becomes available. Only those investments associated with unacceptable risks to the operability or sustainability of the system are advanced to execution.

For instance, the Slave Falls Transformer Banks Replacement & Spare Purchase project appears under Generating System - Sustainment - System Renewal. This project is being executed to renew assets as a means of sustaining the generating system. It was advanced to execution in 2018/19 as the existing assets pose an unacceptable risk to the short term operability and/or long term sustainability of the generating system.

d) The term “active” as it has been referred to on page 16, is not an indication of project status or where the project is in terms of planning. The term "active" means that there is an active need for the investment in the project as a result of a short term operational requirement or the long term sustainability of the electric system. The status of a project is listed in Appendix II of CEF18 (filed as Appendix 6 of the 2019/20 Electric Rate

Application) and is categorized as either Executing Project (i.e. commenced construction) or New Project (i.e. contracting or planning stages).

REFERENCE:

17/18 & 18/19 GRA, PUB MFR 20, Appendix 3 p.41, PUB I-51

PREAMBLE TO IR (IF ANY):

On page 110 of Order 59/18, the PUB found that it did not accept the Business Operations Capital (BOC) spending forecast in CEF16 as condition-driven and reasonably required for the safe and reliable operation of the system. In Recommendations No. 1 and 2 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH defer $160 million of BOC spending to a future period beyond 2018/19 and continue to find reductions in BOC spending during the current period of record spending on major capital projects. On page 31 of the current application, MH indicates that the BOC target for 2019/20 in CEF18 (presumably approved by the MHEB in October of 2018) did not materially change as compared to CEF16 and on page 16 of the current application states that all 2018/19 projects are active and cannot be cancelled without a cost to the safe and reliable services being provided.

QUESTION:

a) In the format used in the response to PUB MFR 20, please provide the impact of a $100 M reduction in annual spending on Business Operations Capital in 2018/19 on the revenue requirement forecast for 2018/19 and 2019/20 by cost components (e.g., Finance/Depreciation/ Operating/Water Rentals/F&PP/Taxes).
b) In the format used in the response to PUB MFR 20, please provide the impact of a $100 M reduction in annual spending on Business Operations Capital in 2019/20 on the revenue requirement forecast for 2019/20 by cost components (e.g., Finance/Depreciation/ Operating/Water Rentals/F&PP/Taxes).

RATIONALE FOR QUESTION:

To understand the impact of reduced spending on Business Operations Capital and MH’s response to PUB findings and recommendations from Order 59/18.

RESPONSE:

a) and b)

The following table provides the estimated revenue requirement impacts of reducing Business Operations Capital spending by $100 million. The first part of the table identifies the estimated revenue requirement impacts in 2018/19 and 2019/20 of a reduction in Business Operations Capital of $100 million in 2018/19. The second part of the table identifies the estimated revenue requirement impacts of a reduction in Business Operations Capital of $100 million in 2019/20. The last line in the table provides the total revenue requirement impacts assuming a reduction of $100 million in BOC spending in both 2018/19 and 2019/20. The total reduction of $100 million in both years results in a combined estimated revenue requirement impact of only $11 million, which represents less than half a percent of Manitoba Hydro’s forecast expenses in 2019/20.

BUSINESS OPERATIONS CAPITAL
REVENUE REQUIREMENT IMPACT
(In Millions of Dollars)

For the year ended March 31

$100M Reduction in 2018/19	**2018/19**	**2019/20**
Finance Expense	(2)	(5)
Depreciation	(1)	(3)
Capital Tax	(0)	0
Total	(4)	(8)
$100M Reduction in 2019/20	**2018/19**	**2019/20**
Finance Expense	-	(2)
Depreciation	-	(1)
Capital Tax	-	(0)
Total	-	(4)
Total Revenue Requirement Impact	**(4)**	**(11)**

On February 14, 2019, Manitoba Hydro filed the 2018/19 Current Outlook and 2019/20 Approved Budget following approval by the MHEB on February 12, 2019. As discussed in the Supplement to the 2019/20 Electric Rate Application, Section 4.0, Business Operations Capital is projected to be $478 million for both the 2018/19 and 2019/20 fiscal years, which reflects a reduction of $37 million and $33 million, respectively. As discussed in the response to PUB/MH I-51b-c, the timing of investment is a complex risk decision and the Corporation reviews the timing of investment execution as part of its annual capital planning process to ensure those investments with unacceptable risk are advanced to execution. In addition, adjustments to the plan are made during the year if anticipated risk exposures do not come to fruition.

REFERENCE:

17/18 & 18/19 GRA, PUB MFR 20, Appendix 3 p.41, PUB I-51

PREAMBLE TO IR (IF ANY):

On page 110 of Order 59/18, the PUB found that it did not accept the Business Operations Capital (BOC) spending forecast in CEF16 as condition-driven and reasonably required for the safe and reliable operation of the system. In Recommendations No. 1 and 2 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH defer $160 million of BOC spending to a future period beyond 2018/19 and continue to find reductions in BOC spending during the current period of record spending on major capital projects. On page 31 of the current application, MH indicates that the BOC target for 2019/20 in CEF18 (presumably approved by the MHEB in October of 2018) did not materially change as compared to CEF16 and on page 16 of the current application states that all 2018/19 projects are active and cannot be cancelled without a cost to the safe and reliable services being provided.

QUESTION:

c) Please provide a summary schedule that compares actual and forecast electric BOC spending for the five-year period from 2013/14 to 2017/18, indicating which CEF has been used for the forecast amounts.

d) In the response to PUB/MH 1-51 b-c (page 3), MH states “The 2019/20 budget cycle is currently underway and will produce an investment plan for 2019/20 and an associated budget, which will be filed following approval from the MHEB and province”. Please explain if MH has prepared a revised outlook for BOC spending for the 2018/19 fiscal year and if so, please provide a summary of the revised outlook compared to the CEF18 forecast. Please also provide the impact on 2019/20 net income of any variance between the revised outlook and CEF18 forecast. Will the revised Capital Expenditure Forecast be available for review at the oral public hearing scheduled for late April 2019?

RATIONALE FOR QUESTION:

To understand the impact of reduced spending on Business Operations Capital and MH's response to PUB findings and recommendations from Order 59/18.

RESPONSE:

c) The following table compares actual performance for the five-year period from 2013/14 to 2017/18 to the approved Capital Expenditure Forecast ("CEF") for each year.

MANITOBA HYDRO
ELECTRIC BUSINESS OPERATIONS CAPITAL EXPENDITURES
FOR THE YEAR ENDED MARCH 31
(in millions of dollars)

	2017/18			2016/17			2015/16		
		CEF16			CEF16			CEF15	
	Actual	Budget	Variance	Actual	Budget	Variance	Actual	Budget	Variance
Generation	$ 89	$ 95	$ 6	$ 84	$ 103	$ 19	$ 110	$ 120	$ 10
Transmission	107	132	25	127	130	3	116	137	21
Distribution	228	244	16	266	272	6	241	245	4
Corporate Assets	37	55	18	53	68	15	67	75	9
Business Operations Capital Total	**$ 461**	**$ 526**	**$ 65**	**$ 530**	**$ 574**	**$ 44**	**$ 533**	**$ 577**	**$ 44**

	2014/15			2013/14		
		CEF14			CEF13	
	Actual	Budget	Variance	Actual	Budget	Variance
Generation	$ 111	$ 132	$ 21	$ 116	$ 135	$ 19
Transmission	144	125	(19)	103	140	37
Distribution	202	239	36	189	188	(0)
Corporate Assets	68	75	8	63	63	0
Business Operations Capital Total	**$ 524**	**$ 571**	**$ 47**	**$ 470**	**$ 526**	**$ 56**

d) As per Section 5.0 in the Supplement to the 2019/20 Electric Rate Application, filed on February 14, 2019, the outlook for Business Operations Capital ("BOC") was revised to $478 million reflecting a reduction of $37 million in anticipated expenditures for 2018/19. As noted in the response to PUB/MH I-53 (Updated), BOC targets are set annually within Manitoba Hydro's planning cycle as portfolio plans are developed for the coming year and forecasts of investment requirements are updated for the years beyond. The reduction in the 2019/20 target reflects refinement of investment requirements as plans to ensure the short term operability and long term sustainability of the electric system are updated based on the best available information.

An updated CEF and Integrated Financial Forecast will be filed as part of Manitoba Hydro's next Electric General Rate Application.

The estimated impact on Net Income for 2019/20 of the change in the Business Operations Capital incorporating the 2018/19 Current Outlook reduction of $37 million and the 2019/20 Approved Budget reduction of $33 million would be a $4 million dollar reduction, as shown in the table below.

MANITOBA HYDRO
ELECTRIC BUSINESS OPERATIONS CAPITAL
FOR THE YEAR ENDED MARCH 31
NET INCOME IMPACT
(In Millions of Dollars)

$37M Reduction in 2018/19	**2018/19**	**2019/20**
Finance Expense	(1)	(2)
Depreciation	(0)	(1)
Capital Tax	(0)	0
Total	(1)	(3)
$33M Reduction in 2019/20		
Finance Expense	-	(1)
Depreciation	-	(0)
Capital Tax	-	(0)
Total	-	(1)
Total Net Income Impact	**(1)**	**(4)**

REFERENCE:

17/18 & 18/19 GRA, PUB MFR 20, Appendix 3 p.41, PUB I-51

PREAMBLE TO IR (IF ANY):

On page 110 of Order 59/18, the PUB found that it did not accept the Business Operations Capital (BOC) spending forecast in CEF16 as condition-driven and reasonably required for the safe and reliable operation of the system. In Recommendations No. 1 and 2 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH defer $160 million of BOC spending to a future period beyond 2018/19 and continue to find reductions in BOC spending during the current period of record spending on major capital projects. On page 31 of the current application, MH indicates that the BOC target for 2019/20 in CEF18 (presumably approved by the MHEB in October of 2018) did not materially change as compared to CEF16 and on page 16 of the current application states that all 2018/19 projects are active and cannot be cancelled without a cost to the safe and reliable services being provided.

QUESTION:

e) In Appendix 3 (page 41) of MH's Application, MH indicates that capital expenditures declined in 2017/18 due to a decrease in resource availability as a result of the VDP. Please explain how MH will have the resource availability to spend its BOC targets in the 2018/19 and 2019/20 years.

RATIONALE FOR QUESTION:

To understand the impact of reduced spending on Business Operations Capital and MH's response to PUB findings and recommendations from Order 59/18.

RESPONSE:

e) Resource availability is a limiting constraint in the delivery of capital investments that is considered in the capital planning process. Adaptation to the reduced staffing levels associated with the Voluntary Departure Program have been required to deliver the capital investments necessary to ensure the short term operability and long term sustainability of the electric system. Adaptations include reflowing of resources to constrained areas, leveraging of external resources to offset internal constraints and balancing portfolio demand to resource availability.

REFERENCE:

17/18 & 18/19 GRA, PUB MFR 20, Appendix 3 p. 41, PUB I-51

PREAMBLE TO IR (IF ANY):

On page 110 of Order 59/18, the PUB found that it did not accept the Business Operations Capital (BOC) spending forecast in CEF16 as condition-driven and reasonably required for the safe and reliable operation of the system. In Recommendations No. 1 and 2 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH defer $160 million of BOC spending to a future period beyond 2018/19 and continue to find reductions in BOC spending during the current period of record spending on major capital projects. On page 31 of the current application, MH indicates that the BOC target for 2019/20 in CEF18 (presumably approved by the MHEB in October of 2018) did not materially change as compared to CEF16 and on page 16 of the current application states that all 2018/19 projects are active and cannot be cancelled without a cost to the safe and reliable services being provided.

QUESTION:

f) Please explain if it is MH’s position that it has little discretion in terms of reducing BOC spending and if so, contrast this position with past fiscal years when MH has underspent its BOC targets?

RATIONALE FOR QUESTION:

To understand the impact of reduced spending on Business Operations Capital and MH’s response to PUB findings and recommendations from Order 59/18.

RESPONSE:

As discussed in Manitoba Hydro’s response to PUB/MH I-51b-c, the timing of investment is a complex risk decision with significant potential operational and cost consequences.

Investments are planned and executed to mitigate risks to the operability and sustainability of the electric system, however are only effective in mitigating risks once in-service.

As discussed in Manitoba Hydro's response to PUB/MH I-53 (Updated), Business Operations Capital ("BOC") targets are set annually within Manitoba Hydro's planning cycle as portfolio plans and budgets are developed for the coming year. The approved budget for the coming year is made up of the investments planned in that year to ensure the short term operability and long term sustainability of the electric system. The BOC target for the year is the aggregation of the cash flows for all of the investments occurring in the 12 months of the fiscal year, which comprise hundreds of projects and thousands of program items and district work orders.

However, investment cash flows are subject to considerable uncertainty due to execution risks manifesting as schedule and budget variances. Examples of the inherent uncertainty in cash flow due to execution risk are given in Manitoba Hydro's response to PUB/MH I-52a-b.

Execution risks impacting schedule are heavily skewed to delaying rather than advancing progress, resulting in a propensity to underspend planned annual cash flow targets as work is pushed out of the current fiscal year. The potential delays resulting from execution risks are assessed in portfolio planning to ensure that the work can be completed in time to mitigate the targeted risks to operability and sustainability of the electric system.

Thus, the underspending of targets is related to uncertainty in the timing of the cash flows required to deliver the investments rather than the scope and budget for the investments needed to ensure the short term operability and long term sustainability of the electric system.

REFERENCE:

17/18 & 18/19 GRA, PUB MFR 20, Appendix 3 p.41, PUB I-51

PREAMBLE TO IR (IF ANY):

On page 110 of Order 59/18, the PUB found that it did not accept the Business Operations Capital (BOC) spending forecast in CEF16 as condition-driven and reasonably required for the safe and reliable operation of the system. In Recommendations No. 1 and 2 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH defer $160 million of BOC spending to a future period beyond 2018/19 and continue to find reductions in BOC spending during the current period of record spending on major capital projects. On page 31 of the current application, MH indicates that the BOC target for 2019/20 in CEF18 (presumably approved by the MHEB in October of 2018) did not materially change as compared to CEF16 and on page 16 of the current application states that all 2018/19 projects are active and cannot be cancelled without a cost to the safe and reliable services being provided.

QUESTION:

g) Please explain why MH has not further adjusted BOC spending in 2018/19 and 2019/20 to mitigate the impacts of its concerns with respect to the volatility of operating results and potential for financial losses?

h) Please provide a detailed quantitative analysis with explanatory notes that reconciles MH evidence from the 2017/18 and 2018/19 GRA that (i) the VDP will generate annual capital expenditure savings of approximately $20 million (Tab 2, Page 51, lines 29 to 31, Tab 3, Page 10, lines 12 to 16) and (ii) the Supply Chain initiative will generate potential cost savings of $150 million from 2017/18 to 2020/21 with 70% related to capital expenditure reductions (Tab 3, Page 10, lines 21 to 25), with the level of projected BOC included in the 2018/19 and 2019/20 BOC targets?

RATIONALE FOR QUESTION:

To understand the impact of reduced spending on Business Operations Capital and MH's response to PUB findings and recommendations from Order 59/18.

RESPONSE:

g) Manitoba Hydro has not adjusted Business Operations Capital ("BOC") spending in 2018/19 and 2019/20 to mitigate the impacts of potential financial losses because capital budgets are managed independently of earnings. Earnings are volatile and unpredictable, whereas stable and predictable funding is needed to mitigate risks associated with the inevitable asset degradation, shifting customer demands, and growing operational requirements that threaten the operability and sustainability of the electric system.

   Manitoba Hydro's earnings are highly variable over short periods of time due to unpredictable factors outside of its control, as discussed in Section 3 of the Supplement to the 2019/20 Electric Rate Application. In most cases, project planning has long lead times under constrained resources with limited flexibility to ramp up or down over short periods. Adjusting budgets for the month to month volatility of earnings is incompatible with the multi-year life cycle of investments and would be highly disruptive if plans and projects tried to follow volatile budgets. The resulting stop/starts would delay investment completion, prolong outages, and add costs from contractor claims and rework.

   As discussed in Manitoba Hydro's response to PUB/MH I-51b-c, the timing of investment is a complex risk decision with significant potential operational and cost consequences. Investments are planned and executed to mitigate risks to the operability and sustainability of the electric system however, they are only effective in mitigating risks once in-service. Predictable and stable budgets reduce in-service uncertainty by avoiding the disruption and delays of funding gaps and thereby allow effective and efficient management of the assets.

h) The Business Operations Capital expenditures shown in Figure 8 of Section 4.0 of the Supplement to the 2019/20 Electric Rate Application are aggregations of the estimated costs to complete the investments needed to ensure the operability and sustainability of the system. The estimates reflect Manitoba Hydro's current operating environment and therefore consider the reduced staffing associated with the Voluntary Departure Program ("VDP") and the procurement improvements associated with the Supply Chain initiative. There is no basis from which to reconcile the payroll savings achieved through VDP or the reduced costs achieved through the Supply Chain initiative with the 2018/19 and 2019/20 BOC targets as both are embedded in the targets.

REFERENCE:

Current Application p.17-18 & 21, 17/18 & 18/19 GRA Coalition I-48, Coalition I-49, Supplement to Tab 3 p.4, PUB I-50 a)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that sets out for the years 2016/17 through 2019/20:
   i. The annual load forecast adjustment for DSM program savings as reflected in IFF16 (i.e., Coalition I-49 (a)).
   ii. Each of the specific adjustments made to (i) for purposes of IFF16 Update (i.e., as discussed in the Supplement to Tab 3) and the resulting annual DSM Adjustments used in IFF16 Update (per Coalition I-49 (a))

b) Please provide a schedule that sets out for the years 2016/17 through 2019/20:
   i. The annual load forecast adjustment for DSM program savings as reflected in IFF16 (i.e., Coalition I-49 (a)).
   ii. Each of the specific adjustments made to (i) for purposes of the current Application (as discussed on page 21, lines 6-8) and the resulting annual DSM Adjustments used in the Current Application. Note: The 2019/20 annual DSM adjustment should reconcile with the 834 GWh value reported in Figure 2.6 of the Current Application.

RATIONALE FOR QUESTION:

To understand the DSM savings incorporated in the Current Outlook and the changes from the last GRA.

RESPONSE:

a) Please see the following table for the requested information.

	IFF16	Adjustments		IFF 16 Update
	Item (i)	Item (ii)		
	DSM Program Savings (GWh)	*Removal of 2016/17 & 2017/18 activity (GWh)*	*Update of 2017/18 Activity (GWh)*	*DSM Program Savings (GWh)*
2016/17	253	(253)	-	-
2017/18	481	(481)	210	210
2018/19	827	(481)	158	503
2019/20	1,255	(479)	158	933

Totals may not add up due to rounding.

b) Please see the following table for the requested information.

	IFF16	Adjustments			Current Application - Supplement
	Item (i)	Item (ii)			
	DSM Program Savings (GWh)	*Removal of 2016/17 - 2019/20 Activity (GWh)*	*Update of 2018/19 Activity (GWh)*	*Update of 2019/20 Activity (GWh)*	*DSM Program Savings (GWh)*
2016/17	253	(253)	-	-	-
2017/18	481	(481)	-	-	-
2018/19	827	(827)	250	-	250
2019/20	1,255	(1,255)	246	231	477

Note: The 2019/20 annual DSM adjustment reconciles with the 477 GWh value reported in Figure 5 on page 11 of the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

Current Application p.17-18 & 21, 17/18 & 18/19 GRA Coalition I-48, Coalition I-49, Supplement to Tab 3 p.4, PUB I-50 a)

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide a schedule that set out for the years 2016/17 to 2019/2020:
   i. The incremental DSM saving for each year per 2016/17 DSM Plan and Supplemental Report 2016-2031 used for IFF16 (per Coalition I-48 (a)).
   ii. The incremental DSM savings for each year per the 2017/18 DSM Plan and the Supplemental Report 2016-2031 used for IFF16 Update (per Supplement to Tab 3 and Coalition I-48 (a)).
   iii. The incremental DSM savings for each year per the Current Application (per page 21).

d) With respect to the responses to Coalition I-48 (a) and Coalition I-49 (a) from the 2017/19 & 2018/19 GRA, please explain why the 2019/2020 savings shown for IFF16 Update in Coalition I-49 (a) of 933 GWh differs from the sum of the incremental DSM savings set out in Coalition I-48 (a) for the years 2017/18 through 2019/20 of 1,006 GWh (i.e., 212+358+436).

RATIONALE FOR QUESTION:

To understand the DSM savings incorporated in the Current Outlook and the changes from the last GRA.

RESPONSE:

c) Please see the following table.

Incremental DSM Savings			
	IFF 16	**IFF 16 Update**	**Current Application - Supplement**
	Item (i)	**Item (ii)**	**Item (iii)**
	2016 DSM Plan - 15 Year Supplemental Report (GWh)	*2016 DSM Plan (Updated) (GWh)*	*Current Application - Supplement (GWh)*
2016/17	255	-	-
2017/18	300	212	-
2018/19	358	358	254
2019/20	436	436	232

Note: The 2019/20 Approved Budget incremental DSM savings of 232 GWh in Item (iii) above is sourced from the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019.

d) The 2019/20 DSM savings of 933 GWh for IFF16 Update presented in Manitoba Hydro's response to COALITION/MH I-49a of the 2017/18 & 2018/19 General Rate Application are lower than the sum of the incremental DSM savings for 2017/18 to 2019/20 of 1,006 GWh presented in Manitoba Hydro's response to COALITION/MH I-48a of the 2017/18 & 2018/19 Electric Rate Application primarily due to the following:

- COALITION/MH I-49a of the 2017/18 & 2018/19 General Rate Application requests the DSM savings used to adjust General Consumer Revenues. DSM savings arising from the Internal Retrofit Program are achieved through improvements to Manitoba Hydro facilities and are therefore not included in the 933 GWh of DSM savings used in determining General Consumer Revenues.
- The response to COALITION/MH I-48a of the 2017/18 & 2018/19 General Rate Application presents annual incremental projected DSM savings. Some savings under the Customer-Sited Load Displacement Program are deemed to have a one-year life, being re-earned each year. Summing the annual incremental savings values from

COALITION/MH I-48a will result in these non-persisting savings from the Customer-Sited Load Displacement Program being double counted.

REFERENCE:

Current Application p.17-18 & 21, 17/18 & 18/19 GRA Coalition I-48, Coalition I-49, Supplement to Tab 3 p.4, PUB I-50 a)

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Similarly, please reconcile any differences between the 2019/20 DSM Adjustment used in the Current Application of 834 GWh and the sum of the incremental DSM savings for 2017/18 through 2019/20 as set out in the response to part (c) - (iii) above.

RATIONALE FOR QUESTION:

To understand the DSM savings incorporated in the Current Outlook and the changes from the last GRA.

RESPONSE:

The 2019/20 annual DSM adjustment as shown in Figure 5 on page 11 of the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019 is 477 GWh. This value differs from the sum of the incremental DSM savings set out in COALITION/MH I-31c for the years 2018/19 to 2019/20 of 486 GWh primarily due to the following:

- The 477 GWh reflects the DSM savings used to adjust General Consumer Revenues. DSM savings arising from the Internal Retrofit program are achieved through improvements to Manitoba Hydro facilities and are therefore not included in the 477 GWh of DSM savings used to adjust General Consumer Revenues. Savings from the Internal Retrofit program are forecast to be 6 GWh.
- The table in COALITION/MH I-31c presents the annual incremental projected DSM savings for 2018/19 and 2019/20. Some DSM savings do not persist into future years. Summing the annual incremental savings values will result in the overstatement of the cumulative savings.

REFERENCE:

Current Application p.17-18 & 21, 17/18 & 18/19 GRA Coalition I-48, Coalition I-49, Supplement to Tab 3 p.4, PUB I-50 a)

PREAMBLE TO IR (IF ANY):

QUESTION:

f) The response to PUB I-50 a) indicates that the 834 GWh of DSM savings for 2019/20 includes 107.6 GWh related to Conservation Rates – Residential & Commercial. Please describe the programs that give rise to these savings.

g) The response to PUB I-50 a) indicates that the 834 GWh DSM savings for 2019/20 includes 51.1 GWh related to Fuel Choice. Please describe the programs that give rise to these savings.

h) Was the DSM spending for 2018/19 and 2019/20 adjusted to reflect the removal of the Conservation Rate and Fuel Choice programs? If so, by how much? If not, what amounts are included for these programs?

RATIONALE FOR QUESTION:

To understand the DSM savings incorporated in the Current Outlook and the changes from the last GRA.

RESPONSE:

f) The Conservation Rates – Residential & Commercial category was included in the 2016/17 Demand Side Management – 15 year Supplemental Report as a placeholder for future programs that would provide a price signal to customers to reduce electricity consumption. These initiatives have been delayed pending the transition of DSM planning and programming to Efficiency Manitoba.

g) The Fuel Choice initiative was included in the 2016/17 Demand Side Management – 15 year Supplemental Report as a placeholder for a future initiative that would encourage customers to choose natural gas over electricity for home and water heating. This initiative has been delayed pending the transition of DSM planning and programming to Efficiency Manitoba.

h) The budgets originally set out in the 2016/17 Demand Side Management – 15 year Supplemental Report for these initiatives was as follows:

Year	Conservation Rates Budget (millions)	Fuel Choice Budget (millions)	Total Budget (millions)
2018/19	$4.171	$10.524	$14.695
2019/20	$4.791	$10.746	$15.537

When developing the 2018/19 one-year DSM Plan in consultation with the Manitoba government, the $14.695 million budget and associated energy savings for 2018/19 for these initiatives was removed. This adjustment was reflected in the 2018/19 DSM Plan and the 2019/20 Electric Rate Application filed on November 30, 2018.

The 2019/20 Approved Budget provided in the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019 reflects the status quo direction based upon on-going consultation with the Province regarding the 2019/20 DSM Plan. The 2019/20 Approved Budget reflects the continued delay of the Conservation Rates initiatives and Fuel Choice program and does not include the planned budgets or associated energy savings from these initiatives.

REFERENCE:

Current Application p.17-18, 21 & Appendix 13, Additional Information Attachment 2, 17/18 & 18/19 GRA, Coalition I-48 (d), PUB I-1 (a) & PUB I-49

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a revised version of the response to Coalition I-48 (d) that includes a column based on actuals for the period up to 2017/18 and the forecast values as used in the Current Application.
b) With respect to Manitoba Hydro's response to Coalition I-48 (d) and PUB I-1 (a) (from the 2017/18 & 2018/19 GRA), please explain why the 2017/18 through 2019/20 amounts reported in Coalition I-48 as spending to be amortized don't match the Power Smart Program expense additions to Regulatory Deferral Accounts as reported in PUB I-1 (a).

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending included in the Current Outlook and the changes from the last GRA.

RESPONSE:

a) Please see the table below for a revised version of the response to COALITION/MH I-48d from the 2017/18 and 2018/19 GRA that includes a column based on actuals for the period up to 2017/18 and the forecast values as used in the Supplement to the 2019/20 Electric Rate Application.

Forecast DSM Spending (millions $)															
	Item (i)			*Item (ii)*			*Item (iii)*			*Item (iv)*			*Item (v)*		
	2014-17 DSM Plan – 15 Year Supplemental Report			*2015/16 DSM Plan – 15 Year Supplemental Report*			*2016 DSM Plan - 15 Year Supplemental Report*			*2016 DSM Plan (Updated)*			*Current Application*		
	Amortized	*Expensed*	*Total*	*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*	$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*	$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**	$50.7*	$0.9*	$51.6*
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	$63.9***	$0.6***	$64.5***
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	$62.9	$0.7	$63.6
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	$61.6	$0.8	$62.3
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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$83.7	$1.2	$84.9
2030/31	-	-	-	-	-	-	$83.2	$1.3	$84.4	$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	$1 165.5	$17.4	$1 182.9

Note: * Reflects actual spending for 2014/15, 2015/16 & 2016/17
** Reflected preliminary unevaluated spending for 2016/17
*** Reflects preliminary unevaluated spending for 2017/18

b) The amounts reported in COALITION/MH I-48 (from the 2017/18 and 2018/19 GRA) as spending to be amortized do not match the DSM expense additions to Regulatory Deferral Accounts as reported in PUB/MH I-1a as COALITION/MH I-48 includes amounts for the Affordable Energy Fund whereas the amounts reported in PUB/MH I-1a includes only the DSM expenditures that are deferred in the regulatory deferral account.

REFERENCE:

Current Application p.17-18, 21 & Appendix 13, Additional Information Attachment 2, 17/18 & 18/19 GRA, Coalition I-48 (d), PUB I-1 (a) & PUB I-49

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Given that the 2019/20 DSM Plan has not been finalized (per page 21), what is the basis for the 2019/20 DSM spending and savings assumptions used in the Current Application? In responding, please explain why the 2019/20 DSM Program expense additions to Regulatory Deferral Accounts are 50% higher than that forecast for 2018/19 (See Attachment 2).

d) The response to PUB I-49 states that the Province has directed a "status quo approach" for 2019/20. What represents the "status quo" for 2019/20 and how does this differ from the spending and savings assumptions used in the Current Outlook for 2019/20.

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending included in the Current Outlook and the changes from the last GRA.

RESPONSE:

c) As outlined on page 14 and 15 of the Supplement to the 2019/20 Electric Rate Application, the 2019/20 Approved DSM Budget for electric DSM has been updated to $61 million based upon preliminary projections for DSM expenditures and activities consistent with on-going consultations with the Province for 2019/20 as contemplated by *The Energy Savings Act*.

d) Manitoba Hydro has been directed by the Province to maintain a status quo approach to DSM with no new program offerings. For 2019/20 this includes the continuation of existing programs with revisions to forecast savings and budgets based on updated market information, and excludes the addition of new programs or initiatives. Based upon the direction from the Province, the forecasted savings and budgets for the future Conservation Rates initiatives and Fuel Choice program have been removed and adjustments have been made to existing program forecasts based on current market information in the development of the 2019/20 1-year DSM plan. This approach is similar to that taken in developing the 2018/19 1-year plan and is reflected in the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

Current Application p.17-18, 21 & Appendix 13, Additional Information Attachment 2, 17/18 & 18/19 GRA, Coalition I-48 (d), PUB I-1 (a) & PUB I-49

PREAMBLE TO IR (IF ANY):

QUESTION:

e) With reference to PUB I-1 (a) and Attachment 2, please explain the following:
   i. The difference between the forecast 2017/18 and the actual 2017/18 Power Smart Program expense additions to Regulatory Deferral Accounts (i.e., $57.2 M vs. $63.7 M)
   ii. The difference between the IFF16 Update 2018/19 forecast and the current 2018/19 forecast for Power Smart Program expense additions to Regulatory Deferral Accounts (i.e., $99.4 M vs. $62.5M)
   iii. Why, as a result of these variances, is there no change between the IFF16 Update and the Current Application in the 2019/20 forecast Power Smart Program expense additions to Regulatory Deferral Accounts ($94.3 M)

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending included in the Current Outlook and the changes from the last GRA.

RESPONSE:

i. The 2017/18 DSM spending was higher than the forecast due to greater than anticipated take up in commercial lighting and solar technology programs as well as higher than projected installations of LED roadway lighting.

ii. The difference between the MH16 Update with interim 2018/19 forecast and the 2018/19 Current Outlook ($63M as per the Supplement to the 2019/20 Electric Rate Application) for DSM program expense additions is due primarily to a reduction in planned DSM spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba.

iii. Please see the response to COALITION/MH I-32c. The $94.3 million for 2019/20 as per the Interim Budget has been reduced below the MH16 Update forecast to $61.2 million in the Approved Budget as per the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

Current Application p.18

PREAMBLE TO IR (IF ANY):

On page 120 of Order 59/18, the PUB found that in light of a new, lower levelized marginal value, a portion of MH's DSM may no longer be cost effective. In Recommendation No. 9 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH review DSM programming for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programs targeted at lower-income and First Nations on-reserve consumers. On page 18 of the current application, MH indicates that as the DSM targets are set in consultation with the Government/Minister, the targets and spending cannot be unilaterally adjusted by MH.

In response to PUB/MH 49 (a), MH states "The marginal values shown in PUB/MH II-57 of the 2017/18 & 2018/19 GRA and exhibit MH-115 will not be used in the development the 2019/20 DSM plan. The 2019/20 DSM Plan is being prepared in consultation with the Province of Manitoba in accordance with The Energy Savings Act. As directed by the Province, the 2019/20 1-year plan, which will be used for the 2019/20 fiscal year, represents a status quo approach and continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba".

QUESTION:

a) Please explain if MH has prepared a revised outlook for DSM spending for the 2018/19 fiscal year and if so, please provide a summary of the revised outlook compared to the CEF18 forecast? Please also provide the impact on 2019/20 net income of any variance between the revised outlook and CEF18 forecast?

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending in the Current Outlook and the changes from the last GRA.

RESPONSE:

a) As per the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019, the 2018/19 Current Outlook for DSM spending remains the same as the November 30th filing at $63 million.

REFERENCE:

Current Application p.18

PREAMBLE TO IR (IF ANY):

On page 120 of Order 59/18, the PUB found that in light of a new, lower levelized marginal value, a portion of MH's DSM may no longer be cost effective. In Recommendation No. 9 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH review DSM programming for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programs targeted at lower-income and First Nations on-reserve consumers. On page 18 of the current application, MH indicates that as the DSM targets are set in consultation with the Government/Minister, the targets and spending cannot be unilaterally adjusted by MH.

In response to PUB/MH 49 (a), MH states "The marginal values shown in PUB/MH II-57 of the 2017/18 & 2018/19 GRA and exhibit MH-115 will not be used in the development the 2019/20 DSM plan. The 2019/20 DSM Plan is being prepared in consultation with the Province of Manitoba in accordance with The Energy Savings Act. As directed by the Province, the 2019/20 1-year plan, which will be used for the 2019/20 fiscal year, represents a status quo approach and continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba".

QUESTION:

b) Please explain if it is MH's position that it has little discretion in terms of reducing DSM spending without Government/Minister approval and if so, explain how this position is consistent with past fiscal years when MH has underspent its DSM targets?
c) Please explain why MH has not adjusted the DSM spending target for 2019/20 based on PUB recommendation No. 9 from Order 59/18 and the PUB findings on page 120 of Order 50/18?

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending in the Current Outlook and the changes from the last GRA.

RESPONSE:

b) Manitoba Hydro has been directed by the Province to maintain a status quo approach to DSM with no new program offerings. Based upon this direction, the forecasted savings and budgets for the future Conservation Rates initiatives and Fuel Choice program have been removed and adjustments have been made to existing program forecasts based on current market information in the development of the 2019/20 1 year DSM plan. The resulting 2019/20 Approved DSM Budget has been reduced to $61 million, as outlined on pages 14 and 15 of the Supplement to the 2019/20 Electric Rate Application.

As targets and budgets are based upon projections of customer participation and uptake, actual expenditures and program savings may differ from those presented under individual DSM Plans.

c) As outlined on pages 14 and 15 of the Supplement to the 2019/20 Electric Rate Application, the preliminary projections for DSM expenditures in the 2019/20 Approved DSM Budget have been reduced to $61 million based upon on-going consultations with the Province as per *The Energy Savings Act*.

REFERENCE:

Current Application p.18

PREAMBLE TO IR (IF ANY):

On page 120 of Order 59/18, the PUB found that in light of a new, lower levelized marginal value, a portion of MH's DSM may no longer be cost effective. In Recommendation No. 9 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH review DSM programming for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programs targeted at lower-income and First Nations on-reserve consumers. On page 18 of the current application, MH indicates that as the DSM targets are set in consultation with the Government/Minister, the targets and spending cannot be unilaterally adjusted by MH.

In response to PUB/MH 49 (a), MH states "The marginal values shown in PUB/MH II-57 of the 2017/18 & 2018/19 GRA and exhibit MH-115 will not be used in the development the 2019/20 DSM plan. The 2019/20 DSM Plan is being prepared in consultation with the Province of Manitoba in accordance with The Energy Savings Act. As directed by the Province, the 2019/20 1-year plan, which will be used for the 2019/20 fiscal year, represents a status quo approach and continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba".

QUESTION:

d) Please explain why MH has not adjusted DSM spending further in 2019/20 to mitigate the impacts of its concerns with respect to the volatility of operating results and potential for financial losses?

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending in the Current Outlook and the changes from the last GRA.

RESPONSE:

As discussed in Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application, decisions on the level of DSM expenditures are made in consultation with the Province of Manitoba as required under *The Energy Savings Act.* The forecast 2019/20 DSM spending reflects the Province's direction to maintain a status quo approach with the continuation of current program offerings while responsibility for DSM transitions to Efficiency Manitoba.

REFERENCE:

Current Application p.18

PREAMBLE TO IR (IF ANY):

On page 120 of Order 59/18, the PUB found that in light of a new, lower levelized marginal value, a portion of MH's DSM may no longer be cost effective. In Recommendation No. 9 from Order 59/18 (issued May 1, 2018), the PUB recommended that MH review DSM programming for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programs targeted at lower-income and First Nations on-reserve consumers. On page 18 of the current application, MH indicates that as the DSM targets are set in consultation with the Government/Minister, the targets and spending cannot be unilaterally adjusted by MH.

In response to PUB/MH 49 (a), MH states "The marginal values shown in PUB/MH II-57 of the 2017/18 & 2018/19 GRA and exhibit MH-115 will not be used in the development the 2019/20 DSM plan. The 2019/20 DSM Plan is being prepared in consultation with the Province of Manitoba in accordance with The Energy Savings Act. As directed by the Province, the 2019/20 1-year plan, which will be used for the 2019/20 fiscal year, represents a status quo approach and continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba".

QUESTION:

e) Please reconcile the 2019/20 DSM budget of $94.3 million with a "status quo approach" recognizing that DSM spending is forecast for 2018/19 year at $62.5 million. Please provide the revised 2019/20 one-year DSM plan referred to in response to PUB/MH 49 (a). Will the revised 2019/20 DSM plan be available for review at the oral public hearing scheduled for late April 2019?

RATIONALE FOR QUESTION:

To understand the basis for the DSM spending in the Current Outlook and the changes from the last GRA.

RESPONSE:

e) As outlined on pages 14 and 15 of the Supplement to the 2019/20 Electric Rate Application, the 2019/20 Approved DSM Budget has been reduced to $61 million. These projections for DSM expenditures and activities are based upon on-going consultations with the Province for 2019/20 as contemplated by *The Energy Savings Act*. The 2019/20 one-year DSM plan will be made public following conclusion of consultations with the Province.

REFERENCE:

Appendix 1, 17/18 & 18/19 GRA, Appendix 6.6 p.6 Figure 6.22 & Exhibit 93

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that the Fuel and Power Purchase forecast in provide Figure 6.22 is consistent with that in Exhibit 93.
   i. If yes, please extend the forecast in Figure 6.22 to 2019/20
   ii. If not, please provide the Fuel and Power Purchase forecast for Exhibit 93 (2017/18 to 2019/20) in the same format as Figure 6.22

b) Please provide a breakdown of the Fuel and Power Purchase forecast in the Current Outlook in the same format as Figure 6.22 and explain any variances (>$ 1M) between this forecast and that underpinning Exhibit 93.

RATIONALE FOR QUESTION:

To understand the Fuel and Power Purchase forecast in the Current Outlook.

RESPONSE:

a) The Fuel & Power Purchase forecast provided in Figure 6.22 of Appendix 6.6 of the 2017/18 & 2018/19 General Rate Application is consistent with that in Exhibit 93. The following table extends the forecast to 2019/20.

Figure 6.22 Updated	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Forecast	2019/20 Forecast
Power purchases	$ 84 532	$ 66 203	$ 78 358	$ 88 270	$ 97 377	$ 101 093
Transmission charges	34 386	42 965	45 626	35 242	36 225	31 772
Thermal fuel purchases	10 201	8 324	8 000	6 495	6 396	24 965
Total fuel and power purchased	$ 129 119	$ 117 492	$ 131 984	$ 130 007	$ 139 998	$ 157 830

b) The following table provides the Fuel & Power Purchase forecast for the 2018/19 Current Outlook and 2019/20 Approved Budget.

Supplement to the 2019/20 Electric Rate Application	2018/19 Current Outlook	2019/20 Approved Budget
Power purchases	$ 99 369	$ 93 665
Transmission charges	29 084	25 976
Thermal fuel purchases	6 295	7 283
Total fuel and power purchased	$ 134 748	$ 126 924

Variance Explanation

2018/19 Current Outlook vs. Figure 6.22/MH16

Power Purchases volumes are down by approximately 350 GWh, however this reduction was more than offset by higher average purchase prices resulting in higher power purchase costs overall.

Transmission Charges are down primarily due to Manitoba Hydro optimizing its firm transmission service portfolio by redirecting some of its firm transmission service to lower cost nodes.

Thermal fuel purchases differed by less than $1 M.

2019/20 Approved Budget vs. Figure 6.22/MH16

Power Purchases volumes are down by approximately 200 GWh largely due to increased hydro generation. Hydroelectric generation is up approximately 1,650 GWh, largely due to higher starting storage and less storage ponding through 2019/20 as compared to the forecast underpinning Exhibit 93.

Transmission Charges are down primarily due to Manitoba Hydro optimizing its firm transmission service portfolio by redirecting some of its firm transmission service to lower cost nodes.

Thermal fuel purchases are down largely due to thermal generation being down by approximately 250 GWh due to higher hydroelectric generation.

REFERENCE:

2019/20 General Rate Application p.35 Line 5-8, and Appendix 11 p.10

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states (page 35) that it is applying for an across-the-board rate increase of 3.5% for all classes and all rate components except for Diesel General Service. For Diesel General Service, MH is proposing to increase the grid portion of the rate (Basic Charge and first 2000 kWh per month for non-government customers) by 3.5% with the non-grid portion of the rate remaining unchanged.

QUESTION:

a) Please explain why the Energy Charge of the Government and First Nation Education Rate (Appendix 11, Page 10 of 26) also remains unchanged at $2.59382 / kWh?
b) Please explain why MH is not applying to increase the non-grid portion of the Diesel General Service Rate (s)?

RATIONALE FOR QUESTION:

To clarify the rate changes Manitoba Hydro is seeking in its Application.

RESPONSE:

a) and b):

Under the terms of the Settlement Agreement, rates in the Diesel communities are designed to recover operating costs only. Diesel rate changes are primarily driven by changes in the price of diesel fuel, which represents over half of the cost to serve the Diesel communities.

Factors such as water flow conditions, interest rates, depreciation rates, or major assets going in service, which impact the need for rate increases from grid customers, do not affect the cost to serve Diesel communities. Therefore Manitoba Hydro has not requested an increase to the Government and First Nation Education rate in this Application.

Rates for all Residential consumption, and General Service usage up to 2,000 kWh per month, are priced at equivalent to grid rates on a policy basis. Manitoba Hydro has proposed applying the 3.5% increase to these rates, which will still remain well below the actual cost to serve these customers.

As noted in Manitoba Hydro's November 12, 2018 letter to the Public Utilities Board, Manitoba Hydro has now received true copies of the diesel Settlement Agreement and intends to address the finalization of the interim diesel zone rates in a separate process to be established, taking into consideration the current regulatory calendar.

REFERENCE:

2019/20 General Rate Application, 33 of 43 lines 27-30

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states (Page 35) that it is applying for an across-the-board rate increase of 3.5% for all classes and all rate components except for Diesel General Service. For Diesel General Service, MH is proposing to increase the grid portion of the rate (Basic Charge and first 2000 kWh per month for non-government customers) by 3.5% with the non-grid portion of the rate remaining unchanged.

QUESTION:

a) In PCOSS18, Appendix 8.1, page 2, the RCC for Diesel (overall) is approximately 82%. Please quantify the overall shortfall in revenue associated with Diesel service in PCOSS18.
b) Please explain how a shortfall in revenue associated with Diesel service is allocated (explicitly or implicitly) to grid customer classes.
c) It appears that based on the MH response to PUB/MH 1-63 (d) that the shortfall in revenue flowing from the rate freeze for Residential Diesel and the First Nations On-Reserve Class was assigned equally, that is 1/8th of the revenue shortfall was assigned to each of the eight customer classes in establishing June 1, 2018 rates. Please confirm.
   i. Was the revenue shortfall assigned to each customer class applied as a cost increase or a reduction in revenue?
   ii. How was the revenue shortfall handled for rate design purposes?
d) If there are any differences in the allocation treatment between (b) and (c) above, please provide the assumptions and rationale.

RATIONALE FOR QUESTION:

To clarify how the revenue shortfall associated with Diesel Rates as well as how Residential Diesel and the First Nations On-Reserve Class is allocated to the various other customer classes.

RESPONSE:

a) Appendix 8.1 of Manitoba Hydro's 2017/18 & 2018/19 Electric Rate Application indicates that the Diesel costs exceeded Diesel revenues by approximately $1.6 million in PCOSS18.

b) The shortfall for the Diesel class noted in the response to part a) is not explicitly allocated to other customer classes in the Cost of Service Study, or during the rate design process. Any foregone or incremental revenues for Diesel, or any other customer class, will affect net income, retained earnings, and the overall levels of future rate increases sought.

c) The June 1, 2018 implementation of the First Nations On Reserve Residential Class did not result in a revenue shortfall for Manitoba Hydro. As per page 29 of Order 59/18, "*Manitoba Hydro is kept whole because the cost of the 0% rate increase for this new customer class has been factored into the level of the average general rate increase granted for the Test Year to all other customer classes.*" In order to keep Manitoba Hydro whole with the implementation of the rate freeze but still achieve the 3.6% overall revenue increase granted in Order 59/18, Manitoba Hydro applied a 3.73% increase to all other classes. The 3.73% average increase was further adjusted on a class-by-class basis to begin moving classes into the zone of reasonableness, while remaining revenue neutral.

d) The treatments described in part b) and c) both result in an incremental rate increases being proportionally applied to the remaining customers classes.

REFERENCE:

2019/20 General Rate Application, 33 of 43 lines 27-30, Order 68/18

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's compliance filing flowing from Order 59/18 does not explain the cost of service methodology changes made, how the rates were differentiated for each customer class, or the resulting RCC ratios by customer class.

QUESTION:

a) Please provide an update of Appendix 8.1 – Schedules 1.1, 1.2 and 1.3 from PCOSS18 that include the effects of differentiated rates flowing from Order 68/18. Please include Diesel and the First Nations On-Reserve Class.
b) Please provide a table that reflects the RCCs in PCOSS18 (as proposed) and builds in each of the changes made to arrive at the final PCOSS18 RCCs flowing from Order 68/18. Please discuss the changes and assumptions made to PCOSS18 (as proposed) including, for example, the treatment of net export revenue as an assignment against cost, the RCC impact flowing from each class' allocated portion of the revenue shortfall associated with the First Nation On-Reserve and Residential rate freeze, and differentiated rates, etc.
c) Please provide a schedule of how the differentiation of rates was derived for each customer class and provide the associated rationale.

RATIONALE FOR QUESTION:

To understand the final revenue requirement by class by which the differentiation of rates was based, how the differentiation of rates was derived, and the movement in RCCs achieved through the implementation of Orders 59/18 and 68/18.

RESPONSE:

a) The following schedules reflect PCOSS18 updated to include the June 1, 2018 differentiated rate increases, as well as utilize the alternate Revenue to Cost Coverage ("RCC") ratio methodology as directed in Order 59/18.

As discussed in Manitoba Hydro's response to PUB/MH 61a, the RCC estimates for the First Nations On-Reserve class are high level estimates that are intended to reflect the RCC impact of the June 1, 2018 rate freeze. Manitoba Hydro does not have separate costs for the First Nations On-Reserve class and is unable to segregate the costs for the class from the overall Residential class in the updated Schedules 1.2 and 1.3.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2018
Revenue Cost Coverage Analysis
Coalition 37a
SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Prior to NER	Net Export Revenue ($000)	Net Cost ($000)	RCC % Current Rates
Residential	763,560	580,111	76.0%	149,708	613,852	94.5%
Residential - FNOR	55,081	40,222	73.0%	10,800	44,281	90.8%
Residential - Seasonal/FRWH	15,069	9,675	64.2%	1,486	13,583	71.2%
General Service - Small Non Demand	156,051	143,329	91.8%	31,317	124,734	114.9%
General Service - Small Demand	190,505	152,656	80.1%	40,099	150,407	101.5%
General Service - Medium	260,775	199,656	76.6%	57,461	203,314	98.2%
General Service - Large 0 - 30kV	123,832	93,292	75.3%	29,601	94,232	99.0%
General Service - Large 30-100kV*	89,370	72,074	80.6%	25,038	64,332	112.0%
General Service - Large >100kV*	236,982	185,926	78.5%	69,997	166,985	111.3%
*Includes Curtailment Customers						
SEP	738	844	114.3%	-	738	114.3%
Area & Roadway Lighting	23,590	22,443	95.1%	1,482	22,108	101.5%
Total General Consumers	1,915,553	1,500,229	78.3%	416,987	1,498,567	100.1%
Diesel	9,032	7,371	81.6%	-	9,032	81.6%
Export	38,159	455,146	1192.7%	(416,987)	455,146	100.0%
Total System	1,962,745	1,962,745	100.0%	-	1,962,745	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2018
Customer, Demand, Energy Cost Analysis

SUMMARY

	CUSTOMER			DEMAND					ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA		Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	78,268	508,242	12.83	403,203	0%	n/a	n/a		190,245	7,586,096	7.82	**
GS Small - Non Demand	14,063	54,988	21.31	70,250	0%	n/a	n/a		40,421	1,622,627	6.82	**
GS Small - Demand	12,455	12,867	80.66	84,810	37%	2,623	11.90		53,142	2,146,454	4.97	
General Service - Medium	9,576	2,125	375.54	114,656	92%	7,722	13.66		79,082	3,204,436	2.75	
General Service - Large <30kV	3,558	321	n/a	47,969	100%	4,302	11.98	*	42,705	1,745,362	2.45	
General Service - Large 30-100kV	2,479	40	n/a	24,232	100%	3,358	7.96	*	37,621	1,578,519	2.38	
General Service - Large >100kV	5,857	16	n/a	55,349	100%	7,815	7.83	*	105,779	4,504,939	2.35	
SEP	68	31	183.11	91	0%	n/a	n/a		579	25,500	2.63	**
Area & Roadway Lighting	16,631	157,982	8.77	3,411	0%	n/a	n/a		2,067	82,415	6.65	**
Total General Consumers	142,955	736,612		803,970		25,818			551,642	22,496,347		
Diesel	401	785	42.61	-	0%	n/a	n/a		8,631	14,546	59.34	**
Export	n/a	n/a	n/a	-	0%	n/a	n/a		38,159	9,166,000	0.42	***
Total System	143,356	737,397		803,970		25,818			598,432	31,676,893		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2018
Functional Breakdown

SUMMARY

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	671,717	303,155	45.1%	69,742	10.4%	38,491	5.7%	73,994	11.0%	186,334	27.7%
General Service - Small Non Demand	124,734	59,907	48.0%	12,182	9.8%	6,673	5.4%	12,715	10.2%	33,257	26.7%
General Service - Small Demand	150,407	77,201	51.3%	15,103	10.0%	8,253	5.5%	7,838	5.2%	42,011	27.9%
General Service - Medium	203,314	111,674	54.9%	20,596	10.1%	11,208	5.5%	8,337	4.1%	51,499	25.3%
General Service - Large <30kV	94,232	58,231	61.8%	9,908	10.5%	5,360	5.7%	2,929	3.1%	17,804	18.9%
General Service - Large 30-100kV	64,332	49,790	77.4%	7,846	12.2%	4,218	6.6%	2,192	3.4%	287	0.4%
General Service - Large >100kV	166,985	139,314	83.4%	21,814	13.1%	0	0.0%	5,611	3.4%	246	0.1%
SEP	738	579	78.5%	91	12.3%	0	0.0%	44	6.0%	24	3.2%
Area & Roadway Lighting	22,108	2,890	13.1%	522	2.4%	283	1.3%	916	4.1%	17,497	79.1%
Total General Consumers	1,498,567	802,742	53.6%	157,803	10.5%	74,487	5.0%	114,576	7.6%	348,959	23.3%
Diesel	9,032	8,631	95.6%	0	0.0%	0	0.0%	0	0.0%	401	4.4%
Export	38,159	38,159	100.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total System	1,545,759	849,532	55.0%	157,803	10.2%	74,487	4.8%	114,576	7.4%	349,361	22.6%

b) Figure 1 below provides the RCC impacts of each of the methodology and revenue adjustments incorporated in the version of PCOSS18 provided in response to part a). Please note that steps are cumulative and the indicated impacts may vary if the steps were performed in a different sequence.

Figure 1: RCC Impacts

	PCOSS18	(i) NER in RCC	(ii) 3.6% Revenue Increase	(iii) FNOR Adjust	(iv) RCC Rate Adjust	Coalition 37a
Residential	95.2%	-1.2%	0.2%	0.0%	0.3%	94.5%
Residential - FNOR	95.2%	-1.2%	-3.1%	-0.1%	0.0%	90.8%
Residential - Seasonal/FRWH	73.6%	-3.0%	0.4%	0.0%	0.2%	71.2%
General Service - Small Non Demand	112.5%	3.2%	0.3%	0.0%	-1.1%	114.9%
General Service - Small Demand	101.0%	0.3%	0.1%	0.0%	0.1%	101.5%
General Service - Medium	98.3%	-0.5%	0.0%	0.0%	0.4%	98.2%
General Service - Large 0 - 30kV	99.1%	-0.4%	0.0%	0.0%	0.3%	99.0%
General Service - Large 30-100kV	109.3%	3.7%	-0.1%	0.0%	-0.9%	112.0%
General Service - Large >100kV	108.6%	3.7%	-0.2%	0.0%	-0.8%	111.3%
Area & Roadway Lighting	100.3%	0.0%	0.9%	0.0%	0.3%	101.5%
Diesel	81.9%	0.0%	-0.3%	0.0%	0.0%	81.6%

i. The RCC calculation was updated to treat Net Export Revenue as a reduction of class cost, rather than as an addition to class revenue.

ii. A 3.6% revenue increase was applied to all classes, excluding the First Nations on Reserve Residential, Diesel Residential, and non-grid equivalent Diesel classes. The Interest (Net Income) portion of the revenue requirement was increased to recognize the additional revenues.

iii. An additional 0.13% revenue increase was applied to all classes, excluding First Nations on Reserve Residential, Diesel Residential, and non-grid equivalent Diesel classes. The Interest (Net Income) portion of the revenue requirement was increased to recognize the additional revenues.

iv. Rate reductions are provided to General Service Small – Non Demand, General Service Large 30-100kV and General Service Large >100kV to begin migrating the classes into the zone of reasonableness over ten years. Rate adjustments as provided in Figure 2 were applied to the remaining classes to maintain revenue neutrality.

c) Figure 2 below provides a schedule of how the differentiation of rates was derived for each customer class in Order 68/18.

Figure 2: Details of Class Rate Adjustments in Order 68/18

Customer Class	(i) 3.6% Revenue Increase	(ii) FNOR Adjust	(iii) RCC Rate Adjust	Total Rate Adjustment
Residential	3.60%	0.13%	0.30%	4.04%
First Nations on Reserve Residential	0.00%	0.00%	0.00%	0.00%
General Service Small Non-Demand	3.60%	0.13%	-0.94%	2.76%
General Service Small Demand	3.60%	0.13%	0.13%	3.86%
General Service Medium	3.60%	0.13%	0.39%	4.13%
General Service Large 750V – 30 kV	3.60%	0.13%	0.32%	4.06%
General Service Large 30-100 kV	3.60%	0.13%	-0.73%	2.97%
General Service Large >100 kV	3.60%	0.13%	-0.67%	3.03%
Area & Roadway Lighting	3.60%	0.13%	0.30%	4.04%
Diesel:				
Diesel Residential	0.00%	0.00%	0.00%	0.00%
Diesel GS Grid Portion	3.60%	0.13%	-0.94%	2.76%
Diesel GS Full Cost	0.00%	0.00%	0.00%	0.00%
Diesel Government	0.00%	0.00%	0.00%	0.00%

i. A 3.6% rate increase was applied to each class with the exception of the First Nations on Reserve Residential class and the Diesel Residential class, whose rates were held at the approved August 2017 rates, per direction in Order 59/18. No adjustments were made to the non-grid equivalent Diesel rates for reasons described in Manitoba Hydro's response to Coalition/MH I-35.

ii. In order to achieve the overall average revenue increase of 3.6%, as indicated in Directive 4 of Order 59/18, an additional 0.13% rate increase was required from all classes other than the First Nations on Reserve Residential, Diesel Residential, and non-grid equivalent Diesel classes.

iii. As directed in Order 59/18, the General Service Small Non Demand, General Service Large 30-100 kV and General Service >100 kV classes were to receive less than average increases to begin migrating those classes into the zone of reasonableness over a ten year period.

The required rate adjustments were calculated based on PCOSS18 using the alternate RCC calculation, which are as follows:

Figure 3: RCC Rate Adjustments

Customer Class	RCC Rate Adjustment
General Service Small Non-Demand	(0.97%)
General Service Large 30-100 kV	(0.74%)
General Service Large >100 kV	(0.67%)

In order to maintain revenue neutrality, an offsetting rate increase is required from other classes. The increase was not applied to FNOR or Diesel Residential classes due to the Order 59/18 rate freeze for the classes, or the non-grid equivalent Diesel rates. A resulting increase of approximately 0.3% was required from the remaining classes to achieve revenue neutrality.

Class average increases were applied equally to all rate components with no adjustments to rate design with the exception of the General Service Small Non-Demand, General Service Small Demand and General Service Medium classes. In calculating rates with consideration to Manitoba Hydro's bill impact objectives and the class harmonization constraint, Manitoba Hydro was unable to precisely recover the targeted revenue increases sought for each General Service sub-class.

The rebalancing resulted in the following increases for the General Service Small and Medium customer classes:

Figure 4: GSS / GSM RCC Rate Adjustments

Customer Class	Target RCC Rate Adjustment	Applied RCC Rate Adjustment
GS Small Non Demand	(0.97%)	(0.94%)
GS Small Demand	0.30%	0.13%
GS Medium	0.30%	0.39%

REFERENCE:

2019/20 General Rate Application, 33 (line 32), 34 (lines 15, 22, 28)

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states (page 34) that it intends to continue the migration of customer classes into the ZOR in its next full General Rate Application.

QUESTION:

Does Manitoba Hydro continue to view that once RCCs are within the ZOR, customer classes can be deemed as paying their fair share of costs (2017/18 General Rate Application, Tab 8, page 29, line 19)? Please explain.

RATIONALE FOR QUESTION:

To clarity of Manitoba Hydro's intention regarding rate differentiation given its responses to PUB/MH I and PUB/MH I-61a (page 3).

RESPONSE:

Manitoba Hydro continues to view that the results of a Cost of Service Study provides a measure of relative rather than absolute costs. It is therefore generally accepted, including by Manitoba Hydro, that if a class RCC falls within the prescribed ZOR then it is deemed to represent full cost recovery.

However, Manitoba Hydro is not of the view that all class RCCs must necessarily be maintained within the ZOR at all times. The Cost of Service Study is a tool which is available to the PUB when setting just and reasonable rates. While maintaining RCC ratios within the ZOR is a consideration, the PUB has discretion to consider any compelling policy issues or other factors that it regards as relevant to approving rates that are just and reasonable. If such discretion is used during the rate setting process, the derived rates may result in RCCs being outside the prescribed ZOR.

REFERENCE:

2019/20 General Rate Application p.34 (lines 23-25)

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states (page 34) that it intends to continue the migration of customer classes into the ZOR in its next full General Rate Application.

QUESTION:

Please confirm that given detailed O&A budgets were not available, for purposes of PCOSS18, Manitoba Hydro relied on detailed O&A budgets flowing from IFF15 prepared in 2015?

RATIONALE FOR QUESTION:

To understand the magnitude of the flexibility within the Zone of Reasonableness and ultimately rate differentiation.

RESPONSE:

The total amount of Operating and Administrative ("O&A") costs included in the revenue requirement of PCOSS18 was based on the 2017/18 forecast from IFF16, which was prepared in 2017.

Functionalization of these O&A costs was based on the detailed results of the budgeting process conducted in early 2016 flowing from IFF15.

REFERENCE:

2019/20 General Rate Application, 34 (lines 23-25), PUB I-61

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states (page 34) that it intends to prepare its next Prospective Cost of Service Study following approval by the MHEB of a new Integrated Financial Forecast.

QUESTION:

Please explain why Manitoba Hydro has not prepared a PCOSS20 for the 2019/20 Test Year in support of this Application, particularly recognizing the potential significant impact of Bipole III on customer class cost responsibility?

RATIONALE FOR QUESTION:

To understand the factors that led to Manitoba Hydro's decision to not prepare PCOSS20.

RESPONSE:

Manitoba Hydro has provided an updated version of PCOSS18 that incorporates the revenue requirement increases from Bipole III in the response to PUB/MH I-61a, which demonstrates the impact on class revenue cost coverage ratios. In addition to updates to the revenue requirement, this update also includes implementation of Directives 24, 25 and 27 from Order 59/18.

REFERENCE:

2019/20 General Rate Application, Page 1 (lines 16 – 19)

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states (page 1) that the new MHEB is currently undertaking a comprehensive review of its operations, forecasts and financial plans.

As part of Manitoba Hydro's compliance filing dated May 15, 2018 (page 9 of 9 of the bill comparisons), Manitoba Hydro reverted to its prior guideline that no class should experience a class revenue increase more than 2% greater than the overall general revenue increase, compared to the 5% constraint included as part of Manitoba Hydro's evidence in the 2017/18 & 2018/19 GRA.

QUESTION:

Please discuss whether the MHEB's comprehensive review is expected to establish new ratemaking objective priorities for the Corporation? This might include, for example, the priority to be placed on fairness and equity (and the degree of reliance on cost) vs. rate stability and gradualism vs. competitiveness of rates vs. rate increase tolerances (such as the 2% or 5% constraint).

RESPONSE:

For clarity, Manitoba Hydro did not revert to a prior guideline as stated in the Preamble. Manitoba Hydro's May 15, 2018 compliance filing applied the same rate design guidelines as discussed in the 2017/18 and 2018/19 GRA and included herein as Attachment 1 to this response. Manitoba Hydro used the bill tolerances as a guide in order to balance the rate design principles of rate stability, gradualism, fairness and equity. Typically a class revenue adjustment related to Revenue Cost Coverage ("RCC") is limited to 2%. For most classes, the adjustment was made in isolation of any other rate design changes so there were no customer implications beyond the overall class level adjustment. In order to maintain the rate harmonization of the GSSND, GSSD and GSM classes, Manitoba Hydro was required to adjust the balance between the basic monthly charge, energy and demand charges. An interpretation of the guidelines would indicate that individual customer impacts could have been as high as 7% (2% + 5%) above the overall 3.5% average; however, Manitoba Hydro limited the additional increase to 2% above the average in order to recognize that the changes were on account of RCC adjustments, not rate design adjustments.

Manitoba Hydro continues to use the established rate design principles and guidelines as included in Attachment 1 when proposing rates whether at the outset of a General Rate Application or in compliance with an Order from the Public Utilities Board of Manitoba. The priority given to the various principles is determined with consideration to the prevailing circumstances at the time of each rate application. The MHEB's comprehensive Corporate Strategic Planning initiative is currently being developed/scoped and as such we are unable to advise if new ratemaking objectives will be a deliverable of this process. Bill tolerances are used as a guide to help ensure that there is a balance between often competing principles.

Manitoba Hydro's Rate Design Guidelines

- **Recovery of revenue requirement** - Rates must provide the Corporation the opportunity to fully recover its allowed revenue requirement.

- **Fairness and Equity** – Rate design should provide for equitable treatment of customers both within a customer class (whereby similar customers receive similar treatment) and between customer classes (whereby dissimilar customers may be treated differently).

- **Rate Stability and Gradualism** – In conformity with the principles of gradualism and sensitivity to customer impacts, annual adjustments to revenues by customer class should be less than two percentage points greater than the overall proposed increase.

  Plus, in consideration of rate design changes the combined impact of proposed class average rate increases and adjustments to rate structure results in customer monthly impacts which fall within Manitoba Hydro's guidelines:

  - For Residential customers, no customer will experience a bill increase which exceeds the greater of $3.00 per month or three percentage points more than the class average increase.

  - For General Service customer, no customer will experience an increase in their average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase.

- **Efficiency** – Manitoba Hydro views this goal in designing rates as the need to provide appropriate price signals regarding the value of energy and to promote the efficient and economic use of energy. The determination of an appropriate price signal may recognize the application of marginal cost considerations.

- **Competitiveness of Rates** - Maintain Manitoba Hydro's competitive position with respect to rates charged by other Canadian utilities for all rate classes.

- **Simplicity and Understandability** – Rate design should be understandable to customers and should be easy to interpret and apply.