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PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain why Mr. Bowman did not use the 2017 load forecast available in PUB MFR 65-Updated in the preparation of Figure 5-1.

b) Please indicate the capital cost assumed in the Plan 5 Level 2 DSM High Keeyask scenario.

RESPONSE:

(a)

In preparing the materials for this proceeding, various analytical materials were prepared early, and as updates occurred throughout the proceeding, the data was replaced in these analytical products. Figure 5-1 was first prepared with the load forecast as filed with the May filing of the GRA. The failure to update the Figure 5-1 inputs with the 2017 Load Forecast provided in July was unintentional.

However two things must be noted:

1) Part of the decline in the 2017 Load Forecast compared to the 2016 Load Forecast is due to Hydro's projected 7.9% rate increases and corresponding elasticity effects putting downward pressure on load. As a result, updating to the 2017 Load Forecast for a scenario using rate increases which are lower than 7.9% is expected to be pessimistic in terms of loads and revenues.

2) To fully update Figure 5-1, both the Load Forecast and a corresponding DSM plan are required. The DSM plan was updated, but the full cumulative savings over and

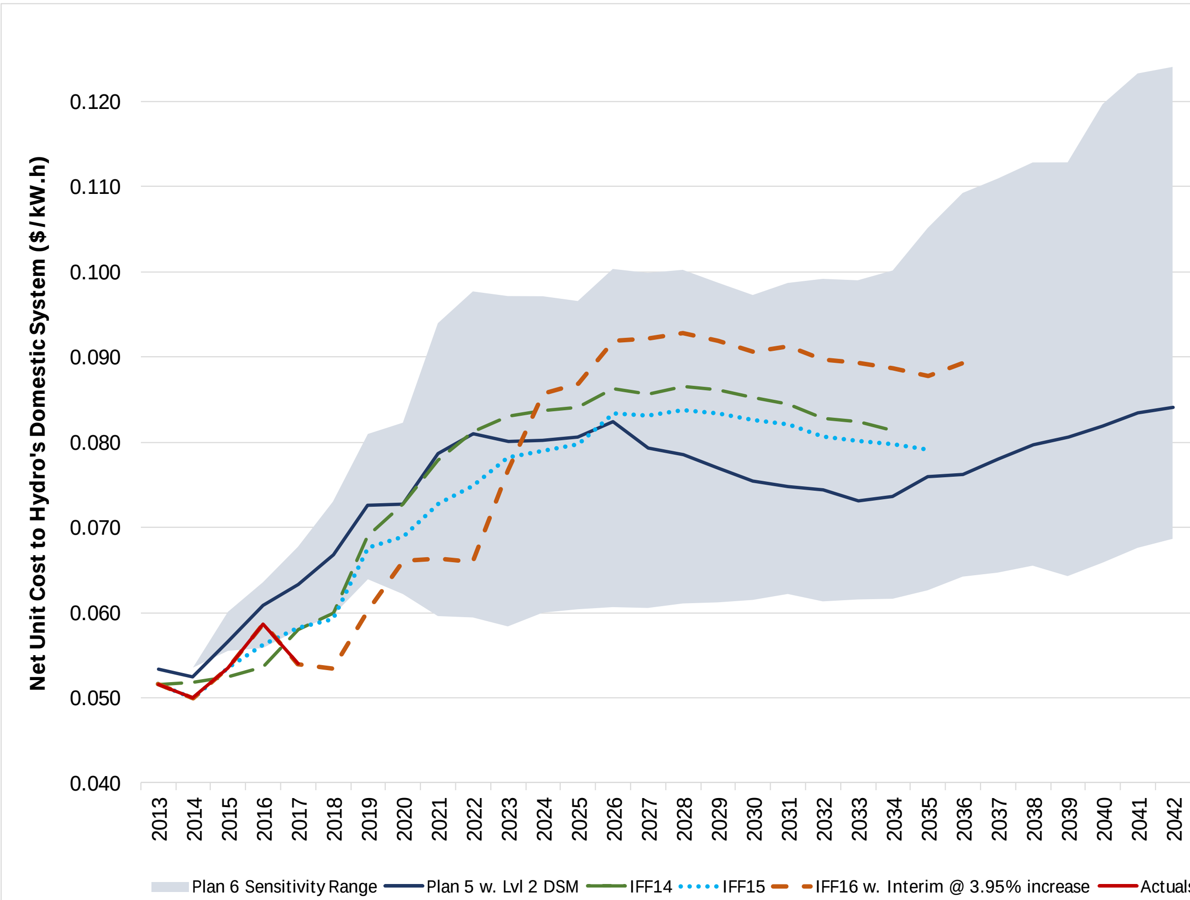
above the 2016/17 actual levels was not provided (all DSM plans available appear to measure cumulative savings over the 2015/16 actual level).

Nonetheless, Figure 5-1 has been updated to reflect the 2017 Load Forecast, as set out below, with an estimate of the updated DSM plan cumulative savings[1]. In general, the updated load forecast does not change the patterns as noted in the Pre-Filed Testimony. The net costs of Hydro's system which are ultimately borne by domestic ratepayers of pursuing the development plan 5/6 still remain below expectations through 2022/23. As Keeyask comes into service (2023/24) on a per kW.h, the costs to which ratepayers are exposed is higher than expected under reference NFAT conditions through the end of the IFF period, but remaining within the range considered for Plan 6 in the NFAT.

To the extent the values changed for the period after 2023/24, it must be kept in mind that this change relates to an update to a load forecast, 3 months after the previous load forecast was filed, relating to load projections 7-20 years in the future.

[1] The DSM cumulative savings were prepared from page 3 of Coalition/MH-I-48a-f Attachment using "Impacts at meter" and subtracting the 2016/17 DSM activity of 255 GW.h from cumulative future savings throughout the horizon (since the 2016/17 savings are already embedded in 2017 load forecast values, and not subtracting this amount would lead to it being double counted). This is likely a slight overestimate of the 2016/17 savings, as these savings likely would see drop offs in future years, but for the purposes of Figure 5-1, the effect is likely trivial.

Figure 5-1: Net Unit Cost of Hydro's Domestic System (before reserves) Under NFAT Plan 5/6 versus IFF16 (assuming 3.95% increase scenario) – Updated for Load Forecast 2017 (PUB-MFR-65)



(b)

Among the changes that have occurred since NFAT, from MH-104-12 in the NFAT Review, the capital cost assumed in the Plan 5 Level 2 DSM High Keeyask scenario (with a 2019 in-service date) is $7.2 billion. The Keeyask control budget used in the current IFF16 is $8.7 billion. This is a significant part of the reason that net costs to ratepayers of Plan 6 has increased, along with such issues as Bipole cost changes, the decreased capitalization of overheads, and declines in export market prices. This is partially offset by savings on interest costs, operating costs, and fuel and import costs where relevant (e.g., the drought scenarios that feed into IFF forecasts) among other factors.

Table 5-1: Net Unit Cost of Hydro's System (before reserves) Calculation for NFAT Plan 5 versus IFF16 (assuming 3.95% increase scenario) Updated for 2017 Load Forecast

$ Millions and GW.h	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
NFAT Plan 5 Level 2 DSM (Ex.MH-104-12-3 Update)																								
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711	724	738	752	768	780	793	815	832	852	870	887
Finance Expense	454	462	511	542	613	694	815	841	1,132	1,247	1,249	1,266	1,268	1,265	1,230	1,210	1,172	1,136	1,150	1,110	1,072	1,070	1,107	1,124
Depreciation and Amortization	408	439	433	463	476	505	543	553	631	675	682	683	687	696	701	695	693	694	717	729	712	707	729	730
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127	127	128	128	128	129	132	131	131	131	131	132
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266	259	273	275	287	295	284	313	325	344	360	350
Capital and Other Taxes	87	95	103	113	122	132	138	143	146	146	147	149	150	151	153	155	158	161	169	170	172	174	176	178
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7
Total Expenses	1,673	1,747	1,835	1,945	2,067	2,221	2,408	2,469	2,916	3,107	3,138	3,180	3,217	3,230	3,232	3,223	3,213	3,203	3,251	3,274	3,251	3,283	3,379	3,407
less: Export and other rev	371	423	398	388	446	507	538	587	869	981	1,010	1,023	1,023	958	1,019	1,006	1,010	1,016	1,050	1,055	1,041	1,029	1,019	1,010
Net costs to ratepayers	1,302	1,323	1,437	1,558	1,621	1,714	1,870	1,882	2,047	2,125	2,128	2,157	2,194	2,273	2,213	2,217	2,203	2,187	2,201	2,219	2,210	2,254	2,359	2,397
Domestic Sales (net of DSM)	24,404	25,239	25,422	25,577	25,624	25,663	25,747	25,857	26,021	26,258	26,567	26,880	27,221	27,566	27,914	28,251	28,603	29,015	29,425	29,827	30,229	30,636	31,048	31,465
Average net cost to ratepayers (before reserves)	0.0533	0.0524	0.0565	0.0609	0.0633	0.0668	0.0726	0.0728	0.0787	0.0809	0.0801	0.0803	0.0806	0.0824	0.0793	0.0785	0.0770	0.0754	0.0748	0.0744	0.0731	0.0736	0.0760	0.0762
MH16 Update with Interim (PUB/MH I-34 Attachment 2)																								
Operating and Administrative					536	518	501	511	513	524	536	548	559	571	583	595	607	620	633	646	660	674	688	702
Finance Expense					608	587	677	749	829	905	1,156	1,202	1,204	1,201	1,214	1,219	1,206	1,194	1,215	1,200	1,197	1,183	1,155	1,128
Finance Income					(17)	(17)	(21)	(28)	(35)	(33)	(37)	(15)	(12)	(14)	(16)	(17)	(16)	(16)	(15)	(17)	(17)	(21)	(22)	(23)
Depreciation and Amortization					375	396	471	515	555	597	689	714	726	739	752	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments					131	130	120	110	113	117	127	128	131	131	131	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased					132	124	140	158	165	156	140	135	138	127	129	131	134	138	147	129	128	134	143	133
Capital and Other Taxes					119	132	145	154	161	165	174	174	175	175	175	176	177	178	179	180	181	182	183	189
Other Expenses					60	116	109	481	94	92	71	64	67	71	76	79	84	87	87	89	91	92	95	96
Corporate Allocation					8	8	8	8	8	8	8	8	8	8	8	8	8	5	3	3	3	3	3	3
less: amounts previously paid through BPIII account					-	-	(3)	(79)	(79)	(79)	(79)	(26)	-	-	-	-	-	-	-	-	-	-	-	-
less: regulatory deferral					(66)	(72)	(114)	(464)	(71)	(64)	(43)	48	50	49	45	44	40	35	33	31	28	28	28	30
Total Expenses	1,407	1,439	1,525	1,649	1,886	1,922	2,033	2,115	2,253	2,388	2,742	2,980	3,046	3,058	3,097	3,132	3,148	3,163	3,220	3,216	3,244	3,266	3,279	3,280
less: Export and other rev	131	159	160	202	488	544	500	451	600	726	813	822	840	702	707	698	714	735	747	744	741	736	734	643
Net costs to ratepayers	1,276	1,280	1,365	1,447	1,398	1,378	1,533	1,664	1,653	1,662	1,929	2,158	2,206	2,356	2,390	2,434	2,434	2,428	2,473	2,472	2,503	2,530	2,545	2,637
Domestic Sales (net of DSM)	24,750	25,625	25,505	24,665	25,896	25,817	25,450	25,214	24,952	25,224	25,175	25,205	25,400	25,647	25,936	26,224	26,499	26,787	27,088	27,554	28,040	28,525	29,021	29,524
Average net cost to ratepayers (before reserves)	0.0516	0.0500	0.0535	0.0587	0.0540	0.0534	0.0602	0.0660	0.0662	0.0659	0.0766	0.0856	0.0869	0.0919	0.0921	0.0928	0.0919	0.0906	0.0913	0.0897	0.0893	0.0887	0.0877	0.0893

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PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide supporting information for the assertion that Manitoba Hydro exports may no longer displace coal generation in the U.S. or Saskatchewan.

b) Please provide information that identifies what type or types of generation in the U.S. and in Saskatchewan that Manitoba Hydro exports are likely to displace.

RESPONSE:

(a) and **(b)**

Increasingly, it should be expected that Hydro's exports are likely to displace natural gas.

Please see GAC-MIPUG-3 and Coalition-MIPUG-1.

This is a newer development as price levels and supply mix has evolved. Consider that in the NFAT proceeding (Appendix 5.3, pdf page 24 of 87) Hydro's export markets, the Brattle Group, were noting that "Over time, gas will progressively displace coal as the price-setting fuel". Further, Brattle Group noted the following (Hydro NFAT Business Case Appendices, pdf page 1236 of 4127):

Emissions displaced (short-term) are in the range 0.5 - 1.0 ton CO_2/MWh

- Not at either extreme – neither coal nor CC are always marginal
  - Historically, coal was marginal almost all the time; somewhat less true in future
- Future displacement depends on how other factors play out over time
  - Gas, coal and CO_2 prices, coal retirements, renewable additions, *etc.*

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PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain whether Mr. Bowman considers Manitoba Hydro's use of its marginal value as calculated in PUB/MH I-131 to be appropriate for the evaluation of DSM measures. If not, please identify what changes Manitoba Hydro should make when evaluating the cost effectiveness of its DSM measures.

RESPONSE:

(a)

Please also see GAC-MIPUG-2 regarding measurements of DSM benefits.

With respect to the marginal value as a measure of DSM benefits, Mr. Bowman notes the following:

1) **Transmission and Distribution estimates are likely low:** On transmission (and distribution), Mr. Bowman has had a standing concern, similar to that noted by Mr. Chernick (pages 19-20), in regards to Hydro's limited scope on which it concludes a given project is load driven versus not load driven for the purposes of calculating the transmission and distribution marginal cost. Mr. Bowman has not updated this assessment in detail for the current proceeding

2) **Generation calculated based on non-public information:** In regard to generation, the noted marginal values are calculated from reports and inputs that are not in the public record, which makes detail comments difficult.

3) **Generation values in PUB/MH-I-131 are dated:** Mr. Bowman notes (per PUB/MH-I-131b-c) that the values quoted are from the 2016 Demand Side Management Plan,

which is based on the 2015 export price forecast. It is clear from the material filed that the 2015 export price forecast is no longer the best representation of Hydro's market outlook. For example, MH16 Update, per Supplement to Tab 3, is based on the 2017 Energy Price Forecast. Hydro notes in the Supplement to Tab 3 that the 2016 forecast was 15% below the 2015 forecast, and that the 2017 forecast is down a further 17% (on peak) to 20% (off peak) over the 2016 forecast.

4) **Long-dated benefits:** Hydro's calculation of the marginal value is based on the data (redacted) at page 3 of PUB/MH-I-131b-c. Though this information is not available to intervenors, Mr. Bowman is aware from other assignments that a significant part of the marginal value in previous forecasts (2015 or prior) was based on benefits arising from high price estimates in the period 2036-2046 (years 20-30 of the forecast). This is not surprising given Hydro's export price forecast has often had significantly long-dated benefits (e.g., see Tab 3 Figure 3.7).

5) **Insufficient detail regarding timing:** The approach to calculating the marginal value reduces load by "a constant increment in each month" but with little information about the daily/weekly/time period pattern. Further this approach would ignore differing benefits by season.

Mr. Bowman's concerns also extend to comments set out in GAC/MIPUG-2, which notes that Hydro's evaluation of DSM programs appear to be based on a test of "can one justify spending on this now" rather than "when is the best time to spend on this" or "would it be better/cheaper/require the utility not to invest if one waited longer" (e.g., if technologies are getting cheaper, or the economics are improving such that in future most customers can be expected to undertake the investment themselves without DSM spending, or codes and standards are likely to change so that no spending on incentives will be needed to achieve the same savings). While this is a normal concern with DSM spending, it is a particularly heightened concern if Hydro's marginal values are based on relatively less economic value for the first 10-20 years compared to a high value in years 20 through 30.

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PREAMBLE TO IR (IF ANY):

Mr. Bowman provides Revenue-to-Cost Coverage ratios on Line 12 of Table 1 and provides historical RCC values in Figure 7-2.

QUESTION:

a) Are the historical RCCs provided in Figure 7-2 calculated in the same manner that Mr. Bowman has used in Table 1?

RESPONSE:

(a)

No. The Figure uses the RCC values from the reported studies, calculated in whatever manner was used by Hydro in the respective studies.

This is for 2 reasons:

1) The data can be readily checked, and no further time consuming calculations are required.

2) For a significant part of the period (since approximately 2006) the Cost of Service studies have included an explicit export class, so that the share of export revenues that were allocated to the class (and aggregated with the class revenues for the purposes of calculating a Revenue to Cost Comparison Ratio under Hydro's approach) were relatively small. With PCOSS18, this has now changed and the effect of Hydro's calculation approach is far more magnified than previously.

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PREAMBLE TO IR (IF ANY):

Mr. Bowman states:

"It is important to note that the premise of TOU Rates does not hinge on load shifting - it builds upon the theory that a particular profile of customer is lower cost to serve that others, due to their load timing (in a manner that is more refined than could be achieved by COS analysis and should hence see lower bills)."

QUESTION:

a) Please explain what is meant by the phrase "more refined".

b) Does Order 164/16 adopt a methodology that allocates cost differently based upon the time of energy use (outside of demand based allocation)?

c) Please identify any elements of the COS methodology adopted by the Board in Order 164/16 that recognize a difference in the cost of serving Residential, GSS, GSM, and GSL rate classes based upon the time of energy use.

d) If the Order 164/16 COS Methodology does not recognize cost to serve differences based upon time of energy use, please explain the basis of the statement above that the costs are lower due to the timing of their load.

RESPONSE:

(a)

The rate design step is an attempt to collect the revenue requirement from a class (as calculated by a Cost of Service study) in a manner that achieves important rate design objectives like fairness and efficiency and pragmatism (which are sometimes competing objectives).

Rates for a class can be designed an infinite number of ways. For example, Hydro collects a portion of the revenue from the GS Large class by way of demand charges. These demand charges are measured each month (even though the cost of service study only considers demand based on an annual peak) and the demand charge to a given customer could be based on a demand level that is higher than used in the month, due to the rate design structure that says the demand units for billing will not be lower than 25% of the contracted demand. This is meant to incorporate consideration that unused contract demand can have cost implications for the system.

The issue of time of use rates is similar. There is a known cost implication to the system from using more power at off peak times than at on peak, even on days where the system is not at an absolute system demand peak (e.g., one of the 50 highest peaks in the Cost of Service study). So a customer whose load profile is favourable compared to the class average (e.g., a customer that sees somewhat more energy use at night, or on weekends, or in shoulder seasons) would see a slightly lower cost under a time of use structure.

Offering this customer a time of use structure, and correspondingly a slightly lower revenue for the utility, is recognition of this lower cost profile.

Ultimately, in the example cited, if no load shifting occurs, the class costs in the COS study will not change, but the class revenue will drop a small amount. This will not directly affect any of the other classes, it will only show up as a reduction in the GS Large RCC ratio. If the revenue drop is large enough to drop the GS Large RCC ratio below 100%, then the difference should be made up by higher than average increases to the class. This will, in effect, lead to slightly higher costs to the customers who do not have advantageous load profiles, as would be intended.

At the present time, it is acknowledged that implementing a TOU option for industrial customers would slightly reduce Hydro's revenue. However, the industrial class is paying rates above costs by almost $20 million for >100 kV and $8 million for 30-100 kV (see Table 7-1). To the extent that the Board concludes that Hydro does not require the full 7.9% proposed, this type of relief should be the first priority for implementing net increases lower than 7.9% (also the GSS Small Non-Demand class at 115.7%, of $19 million above cost).

(b), **(c)** and **(d)**

No, Order 164/16 does not allocate costs differently based on the time energy is used.

However, as noted above, this is not a barrier to considering incremental cost implications of power use in rate design (or other considerations). For example, the Cost of Service study also does not allocate any demand costs on the basis of peak demands set by a customer in

September, but the rate design charges customers for peak demand loads used in September. Similarly, a customer may face a high demand charge in January (including a 25% ratchet set off this demand peak, charged in the following 12 months if the January peak is high enough) even if the January peak set by this specific customer was not coincident with any of the 50 highest peaks for the system, which is what the COS considers.

Similarly, the GS Small and Medium rate design incorporates a given unit cost per kW.h for energy consumed up to a given threshold (11,000 kW.h per month) and a second price for the next 8,500 kW.h, and a third price for the balance of the kW.h consumed.

The set of methods to calculate how much of costs should be collected from one class versus another (Cost of Service) is not the only determination for concluding the relative methods on how total RCC costs should be recovered from among the customers in the class (Rate Design), despite all energy in the COS study attracting equal costs.

The Cost of Service study measures costs from one perspective, which is to determine cost allocation to the classes to achieve fairness. Other perspectives on cost can also be relevant to rate design.

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PREAMBLE TO IR (IF ANY):

Mr. Bowman states:

"this could lead to a revenue loss to Hydro."

QUESTION:

a) Please explain whether a customer that chooses the optional TOU Rate and does not make any change in the timing of their energy consumption provides a lower cost to serve to the rate class of that customer, based upon the COS methodology in Order 164/16.

b) If the answer to (a) above is that the costs to serve do not change, how would Mr. Bowman propose to recover the revenue target assigned to that rate class?

c) Does Mr. Bowman have a different opinion of revenue loss cost recovery if TOU rates are offered to other rate classes and not GSL?

RESPONSE:

(a) and **(b)**

If there is no change to usage, the cost to serve that class will not go down. For example, under a hypothetical GS Large TOU rate the revenue implications associated with the rate (assuming no load shifting) were set out in response to MIPUG/MH I-5(a) as follows:

Table 1: Individual Bill Impacts Associated with the Proxy 2016 TOU Rates[1]

Bill Impact TOU vs Standard GSL Rate Design
900,200
438,500
140,300
114,700
39,500
36,800
400
(29,700)
(70,800)
(96,900)
(103,800)
(221,500)
(294,400)
(711,000)

The attachment provided in the response makes it clear that the above 14 rows correlate to individual GSL >100kV customers in the GSL>100kV class.

If each of the customers noted as saving under a TOU design (designated as a negative amount, i.e. 7 customers) were to take advantage of the TOU design, the total revenue loss would be approximately $1.5 million.

The class as a whole currently imposes $160.6 million in costs on the system (per PCOSS18, as shown in Table 7-1 of the Pre-Filed Testimony) and pays rates totalling $180.5 million. If this $1.5 million in revenue were foregone and no shifting was to occur, the class would impose the same $160.6 million in costs, and pay $179.0 million in rates, leading to a RCC ratio of 111.4%, which is still outside the Zone of Reasonableness by 6.4%, or $10.3 million.

In short, even after imposing an optional TOU rate with no load shifting, under PCOSS18 assumptions, if Hydro's revenues are to be held whole, a further $10.3 million would need to

[1] MIPUG/MH I-5c.

be paid by other customer classes rather than GSL >100 kV before the industrial class rates would even reach the outer bounds of what is defined as reasonable.

However, Mr. Bowman would propose that the revenue loss associated with the $1.5 million reduction would not be “recovered” at all. This could be implemented by revising Hydro’s rate increase request down by $1.5 million (e.g., from 7.9% to approximately 7.8% on average).

It is important to note that the implication in the question is that Manitoba can only move towards fairer and more reasonable rates (as defined by a Zone of Reasonableness) by having some other class bear disproportionate cost impacts. Such view is not supported by the evidence. As shown in Figure 7-2, the GSL >100 kV class has seen rates consistently on the order to 10% above costs for most of the last 20 years or more (at least since Order 51/96 directed Manitoba Hydro to work on solving the “persistent problem” of the GSL class being outside the Zone of Reasonableness). As this class has been on the order of $150-$200 million in revenue over the period, the total paid in <u>rates above costs</u> is likely on the order of $300 million[2] or more – where costs already include a full contribution to reserves. This is similar for the GS Small classes, which at a persistent 5% above costs (on a revenue base around $200-$250 million) likely have paid well over $100 million in rates above costs.

(c)

No, if the revenue loss can be accommodated within the rates paid that are above costs.

However, this does not apply to any class at the present time except the GS Small Non-Demand, which by definition cannot likely participate in time of use rates (the Non-Demand class is made up of the smallest GS customers who would not have the metering necessary to apply a Time of Use rate).

[2] 10% of $150 million over 20 years.

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PREAMBLE TO IR (IF ANY):

Mr. Bowman states:

"The implementation of TOU rates on an optional basis could provide a permanent benefit to some customers who have a lower-cost-than-average profile. There is no apparent downside to moving forward at the earliest opportunities, using a rate design along the lines of MIPUG/MH I-5f Attachment."

The attachment references a presentation to MIPUG by Manitoba Hydro on January 11, 2017 regarding Time of Use Rates. On pages 12, 15, and 16 of that presentation, Manitoba Hydro presented three proposed illustrative examples of Time of Use Rates. Definitions for certain terms of service under the example rate structures were provided on page 9.

QUESTION:

a) What specific criteria does Mr. Bowman propose to use to identify the preferred Time of Use Rate? Can Mr. Bowman identify which, if any of these examples, is the preferred option? If none of the examples proposed by Hydro meet Mr. Bowman's criteria, please propose a specific Time of Use Rate for consideration in this application.

RESPONSE:

(a)

The three rate design concepts presented show very little variation in the main factors. Example 1 (page 12) is the middle scenario for all variables. Example 2 pushes the demand charge slightly lower ($3.16/kVA versus $3.48/kVA) and hence has slightly higher energy charges. The effect of higher energy charges (compared to Example 1) is spread across all periods, so the off peak rate is not quite as large a reduction, and the on-peak rate is slightly more of an increase. Example 3 is the opposite (slightly higher demand charges than Example 1, slightly lower energy charges, which means it shows the lowest off peak energy price, and the least peak period energy price signal). Within the range of benefits that may arise from TOU, the three examples are likely to yield at most extremely small differences. For simplicity, Mr. Bowman expects the middle scenario (Example 1) is as good as any of the others.

There is insufficient information in the presentation regarding the impact and necessity of moving to a 50% of contract demand ratchet (from the current 25%). The need for this should be further explored before such a move is made. It is reasonable that customers should not hoard contract capacity that goes unused for long periods, however if that capacity is used at times (e.g., if a customer is just in a temporary downturn) or if the capacity is used off-peak, or if the contracted capacity relates to facilities (substations, lines) to which the customer contributed when they first were connected, then a punitive measure tied to unused contract demand may not be appropriate.

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PREAMBLE TO IR (IF ANY):

MIPUG states:

"The impacts of the depreciation procedure imposed by Hydro should be deferred throughout the horizon, and there is no basis to amortize these balances into rates at any time as the intention is that this variance is self-balancing."

MIPUG offers an alternative where MH would operate a deferral account, but with no amortization of the balance, allowing the net difference between ASL and ELG resolve over time. This approach would be based on Hydro's explicit testimony that ELG is not more expensive over time, and that as assets age the ASL approach will become more costly than ELG and allow for a measured drawdown of the balance of the deferral. This perspective on ELG as higher cost than ASL for some period, then lower costs after a 'crossover' point was highlighted by Hydro in each of the last two GRAs when advocating in favour of the ELG approach, and reiterated by the PUB in Order 73/15:

"Under either ASL or ELG, Manitoba Hydro is eventually made whole, since by the time an asset is decommissioned, the entire capital cost has been recovered by Manitoba Hydro from ratepayers."

MH states:

"If the PUB did not permit the recovery of the difference in depreciation expense between the Equal Life Group (ELG) and CGAAP Average Service Life (ASL) methodologies, Manitoba Hydro understands that it would not be permitted to maintain a regulatory deferral account per the requirements of IFRS 14. If Manitoba Hydro cannot recover the difference in depreciation methodologies in future rates, then a deferred asset would not exist."

QUESTION:

a) Would the effect that the balance will theoretically reverse in the future preclude the need to write off the balance? Please explain and provide an illustration.

b) If the balance was required to be written off for financial reporting purposes, what is your recommended regulatory treatment for rate setting purposes?

RESPONSE:

(a)

Potentially, yes. The pre-filed testimony of Mr. Bowman focuses on the net outcome for rates – that is, a depreciation cost each year that is representative of the ASL procedure, using an appropriate componentization (i.e., assets with materially different life expectations would not be part of the same component).

The question above relates not to how power rates are to be set, but to how Hydro may then account for the impacts of regulation. Mr. Bowman agrees with the Board in its letter of April 4, 2016 (Appendix 10.9, page 3-5) that it is preferable that the financial statements largely match the regulatory statements, but that he Board cannot provide any form of binding guidance to Hydro on how to account for the effects of regulation.

In the event a deferral would be applied by Hydro on the basis described in the preamble, the numerical calculations are already shown in the response to MIPUG/MH II-13a-b. This reference is to a 5 page table (pages 3 of 8 to 8 of 8) replicated below for ease.

MIPUG/MH II-13(a)
Case 1 2015 GRA, ELG - CGAAP ASL comparison
Assumes 20 year amortization of ELG-CGAAP ASL difference (starting in 1923)

Year	Cost	ELG Annual Rate	ELG Annual Expense	CGAAP ASL Annual Rate	CGAAP ASL Annual Expense	Annual ELG - ASL Deferral	Cumulative ELG - ASL Deferral	Annual (20 yr) Amortization ELG-ASL Difference	Cumulative Amortization ELG-ASL Deferral	Unamortized Balance ELG-ASL Difference
1923	1 000.00	0.87%	8.70	0.823%	8.23	0.47	0.47	-	-	0.47
1924	999.99	0.87%	8.70	0.823%	8.23	0.47	0.94	0.02	0.02	0.92
1925	999.98	0.87%	8.70	0.823%	8.23	0.47	1.41	0.05	0.07	1.34
1926	999.97	0.87%	8.70	0.823%	8.23	0.47	1.88	0.07	0.14	1.74
1927	999.96	0.87%	8.70	0.823%	8.23	0.47	2.35	0.09	0.23	2.11
1928	999.95	0.87%	8.70	0.823%	8.23	0.47	2.82	0.12	0.35	2.47
1929	999.94	0.87%	8.70	0.823%	8.23	0.47	3.29	0.14	0.49	2.80
1930	999.93	0.87%	8.70	0.823%	8.23	0.47	3.76	0.16	0.66	3.10
1931	999.91	0.87%	8.70	0.823%	8.23	0.47	4.23	0.19	0.85	3.38
1932	999.89	0.87%	8.70	0.823%	8.23	0.47	4.70	0.21	1.06	3.64
1933	999.87	0.87%	8.70	0.823%	8.23	0.47	5.17	0.23	1.29	3.88
1934	999.85	0.87%	8.70	0.823%	8.23	0.47	5.64	0.26	1.55	4.09
1935	999.83	0.87%	8.70	0.823%	8.23	0.47	6.11	0.28	1.83	4.28
1936	999.80	0.86%	8.60	0.823%	8.23	0.37	6.48	0.31	2.14	4.34
1937	999.77	0.86%	8.60	0.823%	8.23	0.37	6.85	0.32	2.46	4.39
1938	999.74	0.86%	8.60	0.823%	8.23	0.37	7.22	0.34	2.80	4.41
1939	999.70	0.86%	8.60	0.823%	8.23	0.37	7.59	0.36	3.17	4.42
1940	999.66	0.86%	8.60	0.823%	8.23	0.37	7.96	0.38	3.55	4.41
1941	999.62	0.86%	8.60	0.823%	8.23	0.37	8.33	0.40	3.94	4.39
1942	999.57	0.86%	8.60	0.823%	8.23	0.37	8.70	0.42	4.36	4.34
1943	999.52	0.86%	8.60	0.823%	8.23	0.37	9.07	0.43	4.79	4.27
1944	999.46	0.86%	8.60	0.823%	8.23	0.37	9.44	0.43	5.22	4.21
1945	999.40	0.86%	8.59	0.823%	8.23	0.37	9.81	0.42	5.65	4.16
1946	999.33	0.86%	8.59	0.823%	8.22	0.37	10.18	0.42	6.07	4.11
1947	999.25	0.86%	8.59	0.823%	8.22	0.37	10.55	0.41	6.48	4.06
1948	999.16	0.86%	8.59	0.823%	8.22	0.37	10.92	0.41	6.89	4.02
1949	999.07	0.86%	8.59	0.823%	8.22	0.37	11.29	0.40	7.30	3.99
1950	998.97	0.86%	8.59	0.823%	8.22	0.37	11.66	0.40	7.70	3.96
1951	998.86	0.86%	8.59	0.823%	8.22	0.37	12.03	0.39	8.09	3.93
1952	998.74	0.86%	8.59	0.823%	8.22	0.37	12.40	0.39	8.48	3.91
1953	998.61	0.86%	8.59	0.823%	8.22	0.37	12.77	0.38	8.87	3.90
1954	998.47	0.86%	8.59	0.823%	8.22	0.37	13.13	0.38	9.25	3.89
1955	998.32	0.86%	8.59	0.823%	8.22	0.37	13.50	0.37	9.62	3.88
1956	998.15	0.86%	8.58	0.823%	8.21	0.37	13.87	0.37	9.99	3.88
1957	997.96	0.86%	8.58	0.823%	8.21	0.37	14.24	0.37	10.36	3.88
1958	997.76	0.86%	8.58	0.823%	8.21	0.37	14.61	0.37	10.73	3.88
1959	997.54	0.86%	8.58	0.823%	8.21	0.37	14.98	0.37	11.10	3.88

MIPUG/MH II-13(a)
Case 1 2015 GRA, ELG - CGAAP ASL comparison
Assumes 20 year amortization of ELG-CGAAP ASL difference (starting in 1923)

Year	Cost	ELG Annual Rate	ELG Annual Expense	CGAAP ASL Annual Rate	CGAAP ASL Annual Expense	Annual ELG - ASL Deferral	Cumulative ELG - ASL Deferral	Annual (20 yr) Amortization ELG-ASL Difference	Cumulative Amortization ELG-ASL Deferral	Unamortized Balance ELG-ASL Difference
1960	997.31	0.86%	8.58	0.823%	8.21	0.37	15.35	0.37	11.47	3.88
1961	997.05	0.86%	8.57	0.823%	8.21	0.37	15.72	0.37	11.84	3.88
1962	996.77	0.86%	8.57	0.823%	8.20	0.37	16.09	0.37	12.21	3.88
1963	996.47	0.86%	8.57	0.823%	8.20	0.37	16.46	0.37	12.58	3.88
1964	996.15	0.86%	8.57	0.823%	8.20	0.37	16.82	0.37	12.95	3.88
1965	995.81	0.86%	8.56	0.823%	8.20	0.37	17.19	0.37	13.32	3.87
1966	995.43	0.86%	8.56	0.823%	8.19	0.37	17.56	0.37	13.69	3.87
1967	995.03	0.85%	8.46	0.823%	8.19	0.27	17.83	0.37	14.06	3.77
1968	994.60	0.85%	8.45	0.823%	8.19	0.27	18.10	0.36	14.42	3.68
1969	994.14	0.85%	8.45	0.823%	8.18	0.27	18.37	0.36	14.78	3.59
1970	993.65	0.85%	8.45	0.823%	8.18	0.27	18.64	0.35	15.13	3.50
1971	993.11	0.85%	8.44	0.823%	8.17	0.27	18.90	0.35	15.48	3.42
1972	992.53	0.85%	8.44	0.823%	8.17	0.27	19.17	0.34	15.83	3.34
1973	991.92	0.85%	8.43	0.823%	8.16	0.27	19.44	0.34	16.17	3.27
1974	991.27	0.85%	8.43	0.823%	8.16	0.27	19.71	0.33	16.50	3.21
1975	990.57	0.85%	8.42	0.823%	8.15	0.27	19.97	0.33	16.83	3.15
1976	989.81	0.85%	8.41	0.823%	8.15	0.27	20.24	0.32	17.15	3.09
1977	989.01	0.85%	8.41	0.823%	8.14	0.27	20.51	0.32	17.47	3.04
1978	988.15	0.84%	8.30	0.823%	8.13	0.17	20.68	0.31	17.78	2.89
1979	987.24	0.84%	8.29	0.823%	8.12	0.17	20.84	0.30	18.09	2.76
1980	986.28	0.84%	8.28	0.823%	8.12	0.17	21.01	0.29	18.38	2.63
1981	985.24	0.84%	8.28	0.823%	8.11	0.17	21.18	0.28	18.66	2.52
1982	984.14	0.84%	8.27	0.823%	8.10	0.17	21.35	0.27	18.94	2.41
1983	982.97	0.84%	8.26	0.823%	8.09	0.17	21.51	0.26	19.20	2.32
1984	981.73	0.84%	8.25	0.823%	8.08	0.17	21.68	0.25	19.45	2.23
1985	980.42	0.84%	8.24	0.823%	8.07	0.17	21.85	0.24	19.69	2.15
1986	979.01	0.84%	8.22	0.823%	8.06	0.17	22.01	0.23	19.93	2.09
1987	977.52	0.84%	8.21	0.823%	8.04	0.17	22.18	0.22	20.15	2.03
1988	975.95	0.84%	8.20	0.823%	8.03	0.17	22.35	0.22	20.37	1.98
1989	974.30	0.84%	8.18	0.823%	8.02	0.17	22.51	0.21	20.58	1.93

MIPUG/MH II-13(a)
Case 1 2015 GRA, ELG - CGAAP ASL comparison
Assumes 20 year amortization of ELG-CGAAP ASL difference (starting in 1923)

Year	Cost	ELG Annual Rate	ELG Annual Expense	CGAAP ASL Annual Rate	CGAAP ASL Annual Expense	Annual ELG - ASL Deferral	Cumulative ELG - ASL Deferral	Annual (20 yr) Amortization ELG-ASL Difference	Cumulative Amortization ELG-ASL Deferral	Unamortized Balance ELG-ASL Difference
1990	972.56	0.83%	8.07	0.823%	8.00	0.07	22.58	0.21	20.79	1.79
1991	970.70	0.83%	8.06	0.823%	7.99	0.07	22.65	0.20	20.98	1.66
1992	968.74	0.83%	8.04	0.823%	7.97	0.07	22.72	0.19	21.17	1.54
1993	966.68	0.83%	8.02	0.823%	7.96	0.07	22.78	0.18	21.35	1.43
1994	964.51	0.83%	8.01	0.823%	7.94	0.07	22.85	0.17	21.52	1.34
1995	962.23	0.83%	7.99	0.823%	7.92	0.07	22.92	0.16	21.67	1.25
1996	959.80	0.83%	7.97	0.823%	7.90	0.07	22.99	0.15	21.82	1.17
1997	957.25	0.83%	7.95	0.823%	7.88	0.07	23.05	0.14	21.96	1.10
1998	954.58	0.82%	7.83	0.823%	7.86	(0.03)	23.02	0.13	22.08	0.94
1999	951.79	0.82%	7.80	0.823%	7.83	(0.03)	23.00	0.12	22.20	0.79
2000	948.87	0.82%	7.78	0.823%	7.81	(0.03)	22.97	0.11	22.31	0.66
2001	945.77	0.82%	7.76	0.823%	7.78	(0.03)	22.94	0.10	22.41	0.53
2002	942.53	0.82%	7.73	0.823%	7.76	(0.03)	22.91	0.09	22.50	0.42
2003	939.14	0.82%	7.70	0.823%	7.73	(0.03)	22.88	0.08	22.57	0.31
2004	935.60	0.81%	7.58	0.823%	7.70	(0.12)	22.76	0.07	22.64	0.12
2005	931.91	0.81%	7.55	0.823%	7.67	(0.12)	22.64	0.05	22.70	(0.06)
2006	928.01	0.81%	7.52	0.823%	7.64	(0.12)	22.52	0.04	22.74	(0.22)
2007	923.95	0.81%	7.48	0.823%	7.60	(0.12)	22.40	0.03	22.76	(0.36)
2008	919.72	0.81%	7.45	0.823%	7.57	(0.12)	22.28	0.01	22.77	(0.49)
2009	915.32	0.81%	7.41	0.823%	7.53	(0.12)	22.16	(0.00)	22.77	(0.61)
2010	910.75	0.80%	7.29	0.823%	7.50	(0.21)	21.95	(0.02)	22.75	(0.80)
2011	905.94	0.80%	7.25	0.823%	7.46	(0.21)	21.74	(0.03)	22.72	(0.98)
2012	900.95	0.80%	7.21	0.823%	7.41	(0.21)	21.53	(0.05)	22.67	(1.14)
2013	895.77	0.80%	7.17	0.823%	7.37	(0.21)	21.33	(0.06)	22.61	(1.29)
2014	890.40	0.80%	7.12	0.823%	7.33	(0.20)	21.12	(0.07)	22.54	(1.42)
2015	884.84	0.80%	7.08	0.823%	7.28	(0.20)	20.92	(0.09)	22.46	(1.53)
2016	879.02	0.79%	6.94	0.823%	7.23	(0.29)	20.63	(0.10)	22.36	(1.73)
2017	873.00	0.79%	6.90	0.823%	7.18	(0.29)	20.34	(0.12)	22.24	(1.90)
2018	866.77	0.79%	6.85	0.823%	7.13	(0.29)	20.06	(0.14)	22.10	(2.05)
2019	860.34	0.79%	6.80	0.823%	7.08	(0.28)	19.77	(0.15)	21.95	(2.18)

MIPUG/MH II-13(a)
Case 1 2015 GRA, ELG - CGAAP ASL comparison
Assumes 20 year amortization of ELG-CGAAP ASL difference (starting in 1923)

Year	Cost	ELG Annual Rate	ELG Annual Expense	CGAAP ASL Annual Rate	CGAAP ASL Annual Expense	Annual ELG - ASL Deferral	Cumulative ELG - ASL Deferral	Annual (20 yr) Amortization ELG-ASL Difference	Cumulative Amortization ELG-ASL Deferral	Unamortized Balance ELG-ASL Difference
2020	853.70	0.79%	6.74	0.823%	7.03	(0.28)	19.49	(0.16)	21.79	(2.30)
2021	846.78	0.78%	6.60	0.823%	6.97	(0.36)	19.13	(0.17)	21.62	(2.49)
2022	839.65	0.78%	6.55	0.823%	6.91	(0.36)	18.77	(0.19)	21.43	(2.66)
2023	832.30	0.78%	6.49	0.823%	6.85	(0.36)	18.41	(0.21)	21.22	(2.81)
2024	824.73	0.78%	6.43	0.823%	6.79	(0.35)	18.05	(0.22)	21.00	(2.94)
2025	816.95	0.78%	6.37	0.823%	6.72	(0.35)	17.70	(0.24)	20.76	(3.06)
2026	808.88	0.77%	6.23	0.823%	6.66	(0.43)	17.27	(0.25)	20.52	(3.24)
2027	800.58	0.77%	6.16	0.823%	6.59	(0.42)	16.85	(0.26)	20.25	(3.40)
2028	792.05	0.77%	6.10	0.823%	6.52	(0.42)	16.43	(0.28)	19.98	(3.55)
2029	783.28	0.77%	6.03	0.823%	6.45	(0.42)	16.01	(0.29)	19.68	(3.67)
2030	774.26	0.77%	5.96	0.823%	6.37	(0.41)	15.60	(0.31)	19.38	(3.77)
2031	764.88	0.77%	5.89	0.823%	6.29	(0.41)	15.20	(0.32)	19.06	(3.86)
2032	755.20	0.76%	5.74	0.823%	6.22	(0.48)	14.72	(0.33)	18.73	(4.01)
2033	745.20	0.76%	5.66	0.823%	6.13	(0.47)	14.25	(0.34)	18.39	(4.14)
2034	734.87	0.76%	5.59	0.823%	6.05	(0.46)	13.79	(0.35)	18.04	(4.25)
2035	724.19	0.76%	5.50	0.823%	5.96	(0.46)	13.33	(0.37)	17.67	(4.34)
2036	713.01	0.76%	5.42	0.823%	5.87	(0.45)	12.88	(0.38)	17.29	(4.41)
2037	701.44	0.75%	5.26	0.823%	5.77	(0.51)	12.37	(0.39)	16.90	(4.53)
2038	689.46	0.75%	5.17	0.823%	5.67	(0.50)	11.87	(0.40)	16.50	(4.64)
2039	677.06	0.75%	5.08	0.823%	5.57	(0.49)	11.37	(0.41)	16.10	(4.72)
2040	664.24	0.75%	4.98	0.823%	5.47	(0.48)	10.89	(0.42)	15.68	(4.79)
2041	650.85	0.75%	4.88	0.823%	5.36	(0.48)	10.41	(0.43)	15.25	(4.83)
2042	637.04	0.74%	4.71	0.823%	5.24	(0.53)	9.89	(0.44)	14.81	(4.92)
2043	622.81	0.74%	4.61	0.823%	5.13	(0.52)	9.37	(0.44)	14.37	(5.00)
2044	608.18	0.74%	4.50	0.823%	5.01	(0.50)	8.86	(0.45)	13.91	(5.05)
2045	593.15	0.74%	4.39	0.823%	4.88	(0.49)	8.37	(0.46)	13.45	(5.08)
2046	577.63	0.73%	4.22	0.823%	4.75	(0.54)	7.83	(0.47)	12.99	(5.15)
2047	561.77	0.73%	4.10	0.823%	4.62	(0.52)	7.31	(0.47)	12.52	(5.20)
2048	545.59	0.73%	3.98	0.823%	4.49	(0.51)	6.80	(0.48)	12.04	(5.23)
2049	529.13	0.73%	3.86	0.823%	4.35	(0.49)	6.31	(0.48)	11.56	(5.25)

MIPUG/MH II-13(a)
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Assumes 20 year amortization of ELG-CGAAP ASL difference (starting in 1923)

Year	Cost	ELG Annual Rate	ELG Annual Expense	CGAAP ASL Annual Rate	CGAAP ASL Annual Expense	Annual ELG - ASL Deferral	Cumulative ELG - ASL Deferral	Annual (20 yr) Amortization ELG-ASL Difference	Cumulative Amortization ELG-ASL Deferral	Unamortized Balance ELG-ASL Difference
2050	512.40	0.73%	3.74	0.823%	4.22	(0.48)	5.84	(0.49)	11.07	(5.24)
2051	495.39	0.73%	3.62	0.823%	4.08	(0.46)	5.38	(0.49)	10.58	(5.21)
2052	478.22	0.72%	3.44	0.823%	3.94	(0.49)	4.88	(0.49)	10.09	(5.21)
2053	460.92	0.72%	3.32	0.823%	3.79	(0.47)	4.41	(0.49)	9.60	(5.19)
2054	443.53	0.72%	3.19	0.823%	3.65	(0.46)	3.95	(0.49)	9.11	(5.16)
2055	426.08	0.72%	3.07	0.823%	3.51	(0.44)	3.51	(0.49)	8.62	(5.10)
2056	408.63	0.72%	2.94	0.823%	3.36	(0.42)	3.09	(0.49)	8.13	(5.03)
2057	391.24	0.72%	2.82	0.823%	3.22	(0.40)	2.69	(0.49)	7.64	(4.95)
2058	373.94	0.71%	2.65	0.823%	3.08	(0.42)	2.27	(0.48)	7.15	(4.89)
2059	356.76	0.71%	2.53	0.823%	2.94	(0.40)	1.86	(0.48)	6.67	(4.81)
2060	339.74	0.71%	2.41	0.823%	2.80	(0.38)	1.48	(0.48)	6.20	(4.72)
2061	323.00	0.71%	2.29	0.823%	2.66	(0.36)	1.11	(0.47)	5.73	(4.61)
2062	306.52	0.71%	2.18	0.823%	2.52	(0.35)	0.77	(0.47)	5.26	(4.49)
2063	289.87	0.71%	1.25	0.823%	2.02	(0.77)	0.00	(0.46)	4.81	(4.81)
2064						-	0.00	(0.47)	4.34	(4.34)
2065						-	0.00	(0.44)	3.89	(3.89)
2066						-	0.00	(0.42)	3.48	(3.47)
2067						-	0.00	(0.39)	3.08	(3.08)
2068						-	0.00	(0.37)	2.72	(2.72)
2069						-	0.00	(0.34)	2.38	(2.38)
2070						-	0.00	(0.32)	2.06	(2.06)
2071						-	0.00	(0.29)	1.77	(1.77)
2072						-	0.00	(0.27)	1.50	(1.50)
2073						-	0.00	(0.24)	1.26	(1.26)
2074						-	0.00	(0.22)	1.04	(1.04)
2075						-	0.00	(0.20)	0.84	(0.84)
2076						-	0.00	(0.18)	0.66	(0.66)
2077						-	0.00	(0.15)	0.51	(0.51)
2078						-	0.00	(0.13)	0.37	(0.37)
2079						-	0.00	(0.11)	0.26	(0.26)
2080						-	0.00	(0.09)	0.17	(0.17)
2081						-	0.00	(0.07)	0.09	(0.09)
2082						-	0.00	(0.06)	0.04	(0.04)
2083						-	0.00	(0.04)	0.00	(0.00)
Total			1 000.00		1 000.00	0.00		0.00		

Of note in the attached table:

- The asset class is a very long-lived asset (a hydraulic generation account with a 140 year truncation) assumed to exist from 1923-2063.
- The cost of the asset example is $1000. Each year a small amount of the asset is assumed to retire.
- The third and fourth column show the ELG rate that would apply assuming Hydro continues with ELG as the standard for financial reporting.
- The fifth and sixth columns show the equivalent for ASL.
- The seventh column (Annual ELG-ASL Deferral) is the difference, which would be charged/credited to the deferral accounts. The balancing reversion that is requested in the questions is shown by the fact that this column sums to zero over the life of the asset.
- The eighth column (Cumulative ELG-ASL Deferral) shows what would be the balance in the account, which reverts back to zero at the end of the asset's life.

It is important to note that if Hydro established the account in multiple subparts (e.g., by account, by vintage) the progression in the early years followed by the decline in the later years would be clear and obvious, and may not give rise to the concern noted by Hydro that the account would not show a clear later recovery in rates. For example, the ELG rate applied to many of the older assets today perhaps would show clear offsets in the deferral account being funded by rates.

(b)

The recommended treatment for rate setting purposes is precisely the same regardless as to financial reporting. The PUB's obligations to establish and maintain just and reasonable rates under the Public Utilities Act should not be dependent on varying interpretations from time-to-time of standards set in London or Geneva. The principle of IFRS is as a reporting standard – to report post-hoc on the status of an entity – it is not meant to be the driver of behavior.

Section:		**Page No.:**	**Bowman pg. 6-11 Line 18-19**
Topic:			
Subtopic:			
Issue:	**PUB/MIPUG – 17 2015 & 2016 GRA**		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file an update to the listing of Peer Canadian hydroelectric generation companies that utilized ASL for depreciation purposes.

RESPONSE:

(a)

Mr. Bowman does not maintain a comprehensive list of utilities on a routine basis. The table provided in this response was provided as referenced in response to PUB/MIPUG-17 in the 2015/16 GRA.

The only adjustment made to the table is the removal of Nova Scotia Power, as the source used in the previous GRA to provide the reference for depreciation procedure was no longer available.

Table 1: Depreciation Methods for Crown-Owned Canadian Utilities

Utility	Depreciation Expense Calculation Method	Study Date
BC Hydro	Average Service Life Method[1]	Gannett Fleming in 2006/2011
BC Transmission Corporation	Average Service Life Method[2]	Gannett Fleming in 2005
Newfoundland Labrador Hydro	Average Service Life Method[3]	Gannett Fleming in 2011 – Note: in its 2017 GRA NLH is proposing to change to the ELG procedure but this is not yet approved.[4]
SaskPower	Average Service Life Method[5]	Gannett Fleming in 2011
Yukon Energy Corporation	Average Service Life Method[6]	KPMG in 2012
Qulliq Energy Corporation (Nunavut)	Average Service Life Method[7]	Gannett Fleming in 2010
Northwest Territories Power Corporation	Average Service Life Method[8]	Gannett Fleming in 2015
FortisBC	Average Service Life Method[9]	Gannett Fleming in 2014
Ontario Power Generation	Average Service Life Method[10]	Gannett Fleming in 2013
Hydro One	Average Service Life Method[11]	Foster Associates 2015

[1] BC Hydro and Power Authority F2017-2019 Revenue Requirement Application did not propose changes to depreciation rates, using the expected useful life method from the 2006 Gannett Fleming Study, page 8-1. 2006 Study updated for componentization in 2011, provided in the F2012 - 2014 Revenue Requirements Application; Appendix G: Gannett Fleming Report on IFRS Componentization. Page 8-11, http://www.bcuc.com/Documents/Proceedings/2011/DOC_27065_B-1_BCHydro_F12_F14-RR-application.pdf

[2] British Columbia Transmission Corporation Transmission Revenue Requirement Application. Appendix B, http://www.bcuc.com/Documents/Proceedings/2006/DOC_11676_B-1B_Transmission_Revenue_Requirement_Application.pdf

[3] Newfoundland and Labrador Board of Commissioners of Public Utilities, P.U.40 (2012). Page 4. http://www.pub.nf.ca/applications/NLH2012Depreciation/files/order/pu40-2012.pdf

[4] Newfoundland Labrador Hydro, 2017 General Rate Application, Volume II, Exhibit 11, pdf page http://pub.nl.ca/applications/NLH2017GRA/applications/NLH%202017%20General%20Rate%20Application%20-%20Volume%202%20-%20Revision%203%20-%202017-10-27.PDF

[5] SaskPower 2018 Rate Application, Response to SRRP Q21, pdf page 32 of 280 (November 13, 2017). www.saskratereview.ca/docs/saskpower2012/saskpower-round-one-interrogatories.pdf

[6] 2017/18 GRA does not include new Depreciation Study. Yukon Energy Corporation, 2012 General Rate Application. Tab 10: Depreciation Study by KPMG. Page 10-7 http://yukonutilitiesboard.yk.ca/pdf/YEC%202012%20General%20Rate%20Application/1338_YEC%202012_2013%20GRA%20FINAL_2012%2004%2027%20Tabs%201-11.pdf

[7] Qulliq Energy Corporation, 2010/11 General Rate Application. Page 3-10 and Appendix C-2. http://www.qec.nu.ca/home/index.php?option=com_content&task=view&id=175&Itemid=0 - Currently have applied for new rates continuing to use ASL method but not yet approved

[8] Northwest Territories Power Corporation, 206/19 General Rate Application, Appendix A, available online: http://www.nwtpublicutilitiesboard.ca/sites/default/files/supporting/1%202016%2006%2030%20NTPC%202016_19%20Phase%20I%20General%20Rate%20Application.pdf

[9] FortisBC Application for 2016 Rates, Appendix C, available online: https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/150911_FBC_Annual_Review_for_2016_Rates_FF.pdf

[10] EB-2013-0321 Depreciation Study available online: http://www.opg.com/about/regulatory-affairs/Documents/2014-2015/F5-03-01%20Depreciation%20Study_20131205.pdf - Average Life Group method continues in use for EB-2016-0152 depreciation

[11] Referred to as Vintage Group, Hydro One 2015 Depreciation Rate Review, Exhibit C1, Tab 7, page 13, available online: https://www.hydroone.com/abouthydroone/RegulatoryInformation/txrates/Documents/HONI_Tx_UpApp_Ex_C_20160720.pdf

Section:	**Section 5**	**Page No.:**	**Bowman – Table 5-3** **pg. 5-19, Lines 3-5**
Topic:			
Subtopic:			
Issue:	**Debt Management**		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how MH should revise its debt terming strategy in the next two years given current plan in light of the indicated surplus cash in table 5-3.

RESPONSE:

(a)

Manitoba Hydro's debt terming strategy should be viewed in large part as a critical evolution of its borrowing approach that is necessitated by the end of the major Keeyask borrowing in the next few years. There is effectively no option not to "term" some of the debt. The need for a terming strategy ties to bringing Hydro back into line with traditional targets regarding Weighted Average Term to Maturity (WATM) (See Bowman Figure 5-4, page 5-13) and normal cycling of debt maturities. Absent a terming strategy at the present time, Hydro would incur debt costs that are higher than needed for the next 5-10 years, and, even under a 3.95% rate scenario, would see cash generation within a few years after Keeyask comes into service that far exceeded debt coming due, which leads to inferior options for cash management. This is shown in Table 5-3 reproduced below:

Table 5-3: Values for Borrowing Requirements and Surplus Cash 2022/23 to 2034/35 under 3.95%/year Rate Increase ($ Millions CAD)[1]

Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash	Net New Borrowings
2022	-	653	547	159	-	1,359
2023	-	296	504	1,752	-	2,552
2024	-	300	-	1,854	150	2,004
2025	-	412	-	1,439	247	1,603
2026	215	750	-	159	179	945
2027	-	1,178	-	111	265	1,024
2028	-	150	-	1,078	340	888
2029	-	60	-	1,218	430	848
2030	131	10	-	853	513	482
2031	-	796	-	-	527	268
2032	-	10	-	-	628	(618)
2033	-	30	-	-	707	(677)
2034	-	-	-	-	822	(822)
2035	-	10	-	-	866	(856)
	346	**4,655**	**1,051**	**8,624**	**5,674**	**9,001**

Table 5-3 shows that MH is forecast to have surplus cash starting in 2023/24 and by 2028/29 this cash exceeds the level of LTD Maturities arising excluding terming. Consider that the debt shown as “Potential 2018-2020 Terming” had been issued, consistent with practice during the recent few years, on an average 20 year basis (i.e., what Hydro has been doing prior to enacting a “Terming” strategy). In that case, very little of the debt shown in the column “Potential 2018-2020 Terming” would come due during the horizon to 2035[2]. Hydro would still be forced to refinance LTD from 2022 to 2027 (as the “Refinance LTD Maturities” column exceeds the “Surplus Cash” column) but after 2027, would have excess cash compared to maturities to a significant degree and for a significant period of time, for up to a decade (when the 2018, 20 year debt would peak coming due).

In short, under any reasonable rate increase scenario, including 3.95% or less, terming is required to reflect the ending of the major Keeyask spending, to reduce debt costs, to bring the WATM back into the traditional range, and to permit debt maturities to arise concurrent with significant surplus case starting a few years after Keeyask is in service. Also note that this surplus cash is on a prospective basis given a mean water flow condition – from a financial perspective, the normal situation for Hydro is water flows better than mean with

[1] Values provided in MIPUG/MH I-20f.
[2] The debt issuance averaging 20 years still means some debt would be issued below and/or above this horizon.

occasional water flows impacts much worse than mean. This means that in the event no major drought arises in this period, cash surpluses could be larger than shown (and conversely, if a severe drought did occur, cash could be much more constrained).

Assuming a 7.9% rate increase scenario is not implemented, Hydro's surplus cash will be lower than shown in the Debt Management Strategy (Appendix 3.5) and the potential terming may be advised at a slightly less aggressive level than proposed in that Strategy, though as always the actual strategy from month to month would depend on conditions as they unfold. This may involve somewhat less 5 year debt issued in the next few years than may be planned in the Debt Management Strategy, while still bringing the WATM down considerably from current levels. Some of the "termed" debt will need to be refinanced when it comes due (e.g., in 5-10 years), but this is a normal part of debt management and well within Hydro's policy guidelines for interest rate exposure.

The vast majority of interest cost savings benefits highlighted in the Debt Management Strategy would still arise.

Section:		**Page No.:**	**6-4, Figure 6-2**
Topic:			
Subtopic:			
Issue:	**Bowman**		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file a table of supporting data points for the analysis.

b) Is its MIPUG's contention that O&A growth post 2011/12 should target CPI?

RESPONSE:

(a)

Please see the response provided to MH/MIPUG (Bowman)-18 for the requested supporting data table.

(b)

In the context of a hydraulically based utility, particularly a utility moving out of a development phase, maintenance of O&A at (or even below) inflation is likely a reasonable goal. This is a simple but helpful measure to avoid getting distracted into the competing downward pressures (e.g., reductions arising from winding down capital projects) and upward pressures (e.g., accounting changes). The 2011/12 level is not the only benchmark that may be relevant, but it was a time when there was a high degree of noted concern by the PUB with the level of O&A costs, such that 2011/12 O&A (adjusted for CPI) may already be too high a benchmark.

Section:		**Page No.:**	**A-16 , Table A-3**
Topic:			
Subtopic:			
Issue:	**Bowman Supplementary Background Papers**		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please indicate which of the Provincially Owned Utilities are fully integrated and comment on the comparative Net debt per Capita relative to Manitoba Hydro.

b) Please provide the Comparison with Saskpower.

RESPONSE:

(a) and **(b)**

Manitoba Hydro is among the only provincially owned utility that is universal in service territory and vertically integrated (the only other example may be Nunavut). In these locations, all distribution, transmission and almost all generation is owned by the single integrated utility. Also, effectively the only function of the company is regulated utility service.

BC Hydro is an integrated utility, in that it provides generation, transmission and distribution services, however it does not provide these services universally. A significant part of British Columbia's generation comes from non BC Hydro sources (including industrial owned plants, other utilities like FortisBC and Nelson Hydro, the provincially-owned Columbia Power Corporation, and Independent Power Producers who sell their entire produce to BC Hydro). For this reason, BC Hydro does not carry all of the debt associated with supplying customers in the province. BC Hydro's debt per capita, for example, will therefore look low as it does not include the debt of IPPs or FortisBC, even though that debt is required to be 100% funded by BC ratepayers.

HydroQuebec is similarly provincially-owned and has functions related to generation, transmission and distribution. However, in the province of Quebec there are other small distributors, and Hydro Quebec secures significant power supplies from such sources as Churchill Falls for which it does not carry the debt.

Newfoundland and Labrador Hydro is an arm of Nalcor Energy, which has a wide range of operations including oil and gas and fabrication. Nalcor Energy also owns the major unregulated power operations in the province, namely Churchill Falls and the still under construction Muskrat Falls project. It is not clear in the table whether the full operations of Nalcor are being summarized, or simply the regulated Newfoundland and Labrador Hydro. If this does focus on the regulated business, the metric would again not be comparable to Manitoba as most of Newfoundland and Labrador's bulk power is sold to the privately owned Newfoundland Power (a subsidiary of Fortis), and the table does not appear to include the debt associated with this largely distribution utility in the total utility debt that must be covered by the provincial ratepayers. Based on the large asset value per capita shown ($26,527) it is also assumed that this includes the massive Churchill Falls project, even though very little of this generation is used to service the province and the project is unregulated and recovers its costs primarily from Quebec.

In respect of New Brunswick Power, Mr. Bowman is not sufficiently versed with the industry in New Brunswick to provide comment.

(b)

SaskPower is a provincially owned vertically integrated utility throughout most of the province, though in some municipalities SaskPower only provides bulk power services (e.g., Saskatoon and Swift Current own their own distribution). Based on publicly available information, SaskPower's total net debt is $6.982 billion[1], or $6,178 per capita (approximately half of Manitoba Hydro's level).

Comparisons between a thermal utility and a hydro utility will show different debt profiles. In particular, note that Manitoba Hydro carries a generating complement that serves all Manitoba needs plus substantial export sales (SaskPower focuses only domestically) and that Manitoba's generating complement has almost no fuel cost (SaskPower trades lower debt/capital investment for substantial fuel costs built into rates). Finally, thermal plants typically have shorter lives than hydro plants. Also SaskPower is embarking on a period with significant expected spending on new generation[2] to address the required replacement of

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[1] SaskPower response to SRRP Q10 in the 2018 Rate Application (pdf page 20 of 280), available online: http://www.saskratereview.ca/docs/saskpower2017/saskpower-2018-rate-application-srrp-round-1-irs-q1-to-q148-public.pdf

[2] Growth and Compliance New Generation Capital Expenditure forecast in SaskPower response to SRRP Q90 in the 2018 Rate Application (pdf page 138 of 280), available online:

thermal plants (both due to shorter lives than hydro plants, and due to environmental concerns), while the Manitoba Hydro data already includes significant spending on the new capital works.

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http://www.saskratereview.ca/docs/saskpower2017/saskpower-2018-rate-application-srrp-round-1-irs-q1-to-q148-public.pdf

Section:		**Page No.:**	**P. Bowman pg. 1-7, 6-8**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Mr. Bowman states with respect to the amortization of $20 Million in capitalized OH costs:

"The amount should be amortized starting in the first year in a manner that reasonably matches what would have occurred had it remained part of Hydro's capitalization mechanics – amortize to income as part of depreciation expense, at a rate representative of the projects to which it is tied, or alternatively a rate which reasonably represents a blended of Hydro's overall asset lives (such as 34 years)."

Mr. Bowman recommends that the difference be amortized over 30 years.

QUESTION:

a) Please indicate Mr. Bowman's position on MH's proposal to recognize gains and losses on the disposal of assets over a twenty-year time frame.

b) Please explain the implications of recognizing gains and losses on the disposal of assets in the period they occur versus amortization and whether either approach would or would not be appropriate from a regulatory perspective.

c) In light of your response to (a), should a deferral and amortization approach be followed for the forecast $50.4 million in restructuring charges in 2017/18 and $2.2 million forecast for 2018/19?

d) Please provide Mr. Bowman's position on MH's proposed treatment of Conawapa Costs.

RESPONSE:

(a) and **(b)**

Gains and losses on disposal are a relatively infrequent event when properly using mass property group accounting. It is possible there would be material gains and losses in certain years associated with large events, like perhaps the retirement of the Brandon coal plant (if adjustments weren't made leading up to the event to prepare). It is possible that IFRS will lead Hydro to attempt to record more gains and losses (to the detriment of the statistical dispersion benefit that is intended through group mass property accounting).

For the purposes of rate setting, Mr. Bowman takes no issue with the deferral and amortization of any recorded amounts consistent with the matching with accumulated amortization. It would be preferable that this similarly more closely track the typical average life of Hydro's assets, such as 30 years.

(c)

Not necessarily. The more critical point is that the PUB and other audiences must recognize that the restructuring charge is not a long-term trend. It is acceptable to absorb one-time non-recurring events in a single year so long as that is not used as a rationale to overreact to the lower net income in that year with actions (such as rate increases, or debt downgrades) that will be of effect in future years (when the non-repeating event will not arise). This is similar to droughts – Hydro's rates or credit ratings should not be drastically affected by a drought, when there is going to be a future reversion toward normal conditions. Hydro has repeatedly made this same point. If the restructuring charges were expected to continue for 10 years, or were sufficiently large to knock the equity/debt levels materially off course, then adjustments are required, and smoothing may be advised. For this timing and this scale of costs, such deferral is probably not beneficial.

(d)

To the extent it has been reviewed, Mr. Bowman takes no issue with Hydro's proposals in respect of Conawapa.

Section:		**Page No.:**	**C.F. Osler & G.D. Forrest pg. 2-3 lines 11-13, pg. 5- 2 lines 11-14**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Review of IFF forecasts as provided by Hydro does not indicate any new lower minimum equity level expected to occur over the next decade compared to what was provided to the PUB in the last GRA.

QUESTION:

a) Please explain the concept of a minimum retained earning target level and how it should be established given past practices. If available, please provide illustrative calculations of how it has been determined at past proceedings.

b) Please indicate what MH provided as a lower minimum equity level at the last GRA.

c) Please indicate what MH should use for a Minimum Retained Earning Target. Over what time period should that attainment of that target be established?

RESPONSE:

(a)

There is a difference between a "minimum retained earning target" ("MRET" as reviewed in the referenced evidence, pg. 5-2 from the PUB 1994 Hydro Rate Review) and "the minimum equity level expected to occur" over a specific time period (as quoted in this IR from pg. 2-3 of the referenced evidence).

In past proceedings of the PUB in the late 1980's and early 1990s, when MRET entered the picture, the concept was proposed as a "target" (versus a minimum level that Hydro should not fall below) to be achieved in some future fiscal year by rates that allowed build-up of the target "equity" reserves. The quantum of MRET was set by Hydro based on estimates of reserves needed to address one or two specific risks, and was adjusted in successive GRAs to reflect changes in the estimated risk costs.

The experience of the 1980s and 1990s shows that achievement of MRET took over a decade after the concept was introduced, and provided the basis for setting more ambitious longer-term Hydro financial targets. During this period, PUB-approved rates were typically set not to exceed expected inflation. During this period Hydro also developed longer-term financial targets, e.g., in late 1989 Hydro introduced a new “long-term” debt/equity target of 85/15, and in late 1995 Hydro introduced a new minimum debt to equity ratio target of 75/25 to be achieved by no later than 2005/06.

Summary of relevant practices during 1980sw and early 1990s is provided below:

- **Context:** As noted in the evidence of Mr. Osler and Mr. Forrest and in Mr. Bowman’s Background Paper A, review of older PUB records indicates Hydro operated with very low equity levels in both absolute and percentage terms during the period leading up to the start of PUB regulation, with the passing of the Crown Corporations Public Review and Accountability Act in the late 1980s. Hydro’s “equity” reserves remained less than 10% from the late 1960’s through to shortly after the mid-1990s, and were less than or close to 5% from the late 1970’s through to the early 1990s (see Figure 1 in the evidence of Mr. Osler and Mr. Forrest).

- **Initial 1984/85 minimum reserve target of $180 to $280 million:** In response to these conditions, Hydro’s Board in 1984/85 introduced a new “reserve policy” with an objective to build reserves to $180 to $200 million sufficient to cover a potential two-year drought. No specific time target was set to achieve this objective or target. The new target introduced the concept of having rates set to build up reserves that would appear on Hydro’s books as “equity”, recognizing that actual current and forecast reserves were well below the stated target. At the end of 1983, Hydro’s “reserves’ (i.e., equity or retained earnings, rather than any specific designated “reserve account”) were only $82 million after withstanding two consecutive years when water levels were well below average.

- **Increase in minimum target to $272 million by 1987/88:** The target reserve amount as initially stipulated by Hydro’s Board increased to reflect increasing cost of a two-year drought. By March 1988, the PUB’s report to the Minister stated that Hydro’s then target reserve of $272 million was not excessive, and “may be too little”.

- **PUB Order 99/89 and Order 43/90:** The PUB in its first review with jurisdiction to approve Hydro rates, recommended in Order 99/89 that Hydro’s Board consider the need for including in its target minimum reserves the potential impact of losses to Hydro's self-insurance program. Hydro's rate filing for 1990/91 in effect adopted this recommendation, amending its minimum reserve target (now called its "short-term target") to include provision for the maximum possible single self-insured loss (then estimated at $40 million in 1987 dollars); IFF89-3 indicated that this new target could be achieved in 1994/95 without jeopardizing rate stability. Hydro's reserves had fallen to $92 million as at March 31, 1989, following low water conditions during 1988/89 that added just under $60 million of costs. Hydro's debt/equity at March 31, 1990 was only 97%:03% (Order 42/90).

- **PUB Order 62/94 – updated minimum reserve target of $370 million**: In the PUB's 1994 Hydro rate review (Order 62/94), the Board accepted as reasonable Hydro's updated MRET of $370 million (based on the requirements set previously), which was now forecast to be achieved by March 31, 1997.

- **PUB Order 51/96 – updated minimum reserve target of $650 million:** By the 1996 GRA (Order 51/96) Hydro had updated its MRET (based on the requirements set previously) to $650 million as of 1995. The Board Order noted that, as of 1995, Hydro only had $343 million in retained earnings.

No calculation or information has been provided since approximately the mid-1990s for a MRET equivalent to the 1990s examples, reflecting the rapid growth after the mid-1990s in reserves and retained earning (equity) as a percent of total capital asset funding.

(b)

As noted in response to (a) above, Hydro has not tended to provide updated MRET amounts after approximately the mid-1990s, i.e., when Hydro's reserves started to grow well above a MRET.

There is a difference between a "minimum retained earning target" ("MRET" as reviewed in the referenced evidence, pg. 5-2 from the PUB 1994 Hydro Rate Review) and "the minimum equity level expected to occur" over a specific time period (as quoted in this IR from pg. 2-3 of the referenced evidence).

IFF14, the financial forecast used in the original filing at the last GRA, showed a minimum expected retained earnings level forecast at 2025/26 of $1.924 billion. The referenced evidence as quoted in this IR notes that Hydro's forecast in the current GRA does not indicate any new lower minimum equity (or retained earnings) level expected to occur over the next decade. The response to PUB/MH II-40 in the current proceeding shows that the minimum expected retained earnings level (with the 3.95% rate increase regime, based on

MH16 Interim with Update) is now forecast to occur in 2027/28 at $2.877 billion (see Figure 1 in response (c) below). Mr. Osler and Mr. Forrest referenced this evidence in the context of assessing the extent, if any, that Hydro's financial risks today are materially greater or less than in the last GRA.

(c)

This response first addresses an updated MRET based on the earlier concepts. It then discusses other financial target options to address the current situation.

Updated MRET Approach

Today the MRET concept may assist in assessing the degree of concern to be attached to lower levels of retained earnings during the current capital expansion period. In this context, however, it is important to remember that MRET was developed as a "target" when actual reserves were well below this level.

Based on the prior experience and practice, a MRET today would likely consider the following:

1) The earlier target looked at a 2-year drought. Since the early 2000s, the tendency has been to consider a 5-year drought as the baseline worst event, though occasionally a 7-year drought is also considered[1].

2) Combined with using a longer period of drought, the concept of a static reserve to address a short-term snapshot-type event over 24 months needs to take into account other intervening effects over the longer 5 to 7-year period (including the fact that Hydro has the ability to seek approval to generate increased net revenues from rate adjustments over that period, it does not have to rely only on what is in reserves at the beginning of the drought).

In this context, the closest one could come to paralleling the earlier MRET is the data provided in PUB/MH II-40 (based on MH16 Interim with Update). In this response, beginning with the 2018/19 retained earnings of approximately $3 billion, the trajectory of retained earnings is shown in the following 2 figures (Figure 1 with a 3.95%/year rate increase regime, and Figure 2 with the 7.9%/year rate increases – each figure provides estimates of retained earnings in millions of dollars):

[1] However, the sum of the annual effects of the 7-year drought is traditionally not worse than a 5-year drought, as the historical 7-year drought includes intervening periods of positive net income and the worst effects of the 7-year drought are typically from a compounding effect on interest cost, not from reduced water flows per se.

Figure 1

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

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

Figure 2

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

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

Under the concept of a Minimum Retained Earnings Target (MRET) today consistent with the logic of the earlier target, the level of retained earnings at the start of a drought would be sufficient to withstand the drought and end at $0, assuming no special rate increase response to the drought. The earlier MRET also included some added reserve provision for the maximum possible single self-insured loss.

As shown in Figure 1, with a 3.95%/year rate increase regime, the retained earnings cost (in terms of reduced retained earnings as at the end of the drought compared to what is forecast without the drought) related to a 5-year drought risk starting in 2019/20 or in 2023/24 would equal approximately $1.4 billion; the retained earnings cost related to a 7-year drought risk would equal approximately $1.8 billion for a drought starting in 2019/20, and approximately $2.1 billion for a drought starting in 2023/24.

Following the approach adopted in the early 1990s, the above drought costs as shown in Figures 1 and 2 could be viewed as updated MRET values which take into account incremental costs and incremental revenues over each time period. Figures 1 and 2 show that over each drought period Hydro expects to have offsetting retained earnings such that the MRET needed to keep retained earnings above $0 without any special rate response is less than an amount equal to “the cost of the drought”.

In different words, the 2018/19 retained earnings of approximately $3 billion are sufficient to withstand both a 5-year and a 7-year drought under the 3.95%/year rate increase regime even <u>without</u> any rate response to the drought (e.g., if the rate increase pattern was stubbornly held to 3.95% despite deteriorating conditions over the 5/7 years). In addition, each drought scenario would provide material residual reserves (retained earnings) to address a maximum single self-insured loss (which has not been assessed as to amount in this analysis).

- The 5-year drought starting in 2019/20 would end in 2023/24 with over $1.8 billion in retained earnings, and the 7-year drought would end in 2025/26 with over $1.1 billion in retained earnings.

- The conditions for a drought starting in 2022/23 are somewhat worse, but the lowest case shown (7-year starting in 2022/23) still ends with almost $900 million in retained earnings (again, with no rate response to deteriorating conditions).

The above Figure 2 highlights what occurs with the 7.9% rate increase regime, which shows that the rate increases are sufficient to establish a financial regime that can come out of the worst drought on record having seen an overall positive net income throughout the event. This rate regime shows that Hydro would, with a 5-year drought starting in 2019/20, still show net income of approximately $600 million during the 5 years of the drought. In short under this rate regime, there is effectively no need for positive retained earnings at the start of the drought and Hydro would still exceed the tests from the earlier minimum retained earnings target. This is part of the rationale for concluding that the 7.9% rate increase regime is simply excessive from any reasonable risk mitigation perspective related to Hydro operations.

In summary, Hydro today meets an updated MRET based on these earlier concepts and approach, and would continue to do so in future years under a 3.95% rate regime. This assessment on its own would support consideration of rate increases less than assumed under the 3.95% rate regime previously proposed by Hydro.

Other Financial Target Options to Address Today's Situation

The earlier PUB experience and practice reviewed in response to (a) above, and in the evidence of Mr. Osler and Mr. Forrest, indicated the relevance, when setting time targets for achieving various financial targets, of constraining rate increases so as not to exceed inflation. Time periods to achieve financial targets, including MRET, were constrained by this key factor as well as by Hydro's ability to constrain capital and operating costs, and by the extent to which the Province imposed new tax and other charges on Hydro's operations and assets.

Hydro today is in the midst of a period with monetarily the largest major capital expansion in its history that started shortly after Hydro attained its long-term financial target debt to equity ratio of 75/25. Today's central financial target issues relate to assessing (a) the significance of the likely lowest level of retained earnings during the next decade (where MRET provides a useful perspective) before reserves once again start to grow rapidly, and (b) a reasonable target time for once again seeking to achieve the long-term financial target debt to equity ratio of 75/25.

Looking at today's context, and accepting that the forecast minimum level of retained earnings over the next decade exceeds any reasonable MRET, setting dollar and time targets to recover specific higher levels of reserves or retained earnings is dependent primarily on the future rate pathway that can be considered economically acceptable, and on the ability to define an acceptable risk threshold. In this context, any such "target" continues to be an objective rather than a level that Hydro cannot be allowed to fall below. And, as in the past, the time to achieve such targets will likely need ongoing adjustment in response to actual conditions.

In adopting a defined acceptable rate increase pathway, the Board can provide guidance as to when new information indicating either adverse or favourable conditions (both of which the Board may want to formally consider) may lead the Board to assess potentially higher or lower rate increases for a period of time. This guidance can assist future modelling to provide more useful assessments as to risk thresholds.

Development of such a set of criteria for rate increases and risk thresholds could be developed by Hydro working in consultation with customers and the Board, for such issues as: what rate response would be considered acceptable (e.g., +/- some specified percentage), what constitutes favourable vs unfavourable performance, etc.

Manitoba Hydro would then have a clear basis for assessment and communication of the sufficiency of its retained earnings level and near-term rate increases.

This type of assessment would not have been possible with the less refined tools available in past years.

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PREAMBLE TO IR (IF ANY):

QUESTION:

a) How should the Board define rate shock in the context of the current rate application?

RESPONSE:

(a)

The Board should define rate shock for the current rate application in the context of the following three factors:

1. Hydro's historic rate increases, which until recently were for a long time at or below inflation;
2. Hydro's most recent IFF projections and rate requests, i.e., in the NFAT and most recent GRAs, and the Board's recommendations and approvals in response to these recent submissions; and
3. Review of current overall economic conditions, including expected general inflation and consumer well-being.

Hydro's proposal for 7.9% rate increases qualify for "rate shock" in the context of the above three factors, i.e., the increases are both unexpected based on all prior information, and are unreasonably high from the perspective of current customer economic conditions and expected inflation.

The Board's recent rate approvals for Hydro have exceeded expected inflation, but also respected the need to avoid rate shock.

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PREAMBLE TO IR (IF ANY):

Hydro's GRA places emphasis on the new debt required for the current surge in generation and transmission asset development – but no attention is directed at the option of securing Provincial approval to defer imposing these current-day high Provincial charges on these new assets in order to assist in the transition over the next decade. Absent such deferral, Provincial revenues from such charges on Hydro will jump once again.

QUESTION:

a) Please indicate what specific deferral in charges should be recommended to the Province.

RESPONSE:

(a)

Provincial charges on Hydro's capital assets (i.e., capital taxes and Debt Guarantee charges) have been extensively increased since Hydro's core generation and transmission assets were initially developed. By way of example, Hydro's exemption from the capital tax was rescinded only in the 1994 Provincial Budget, and the Debt Guarantee charge levels applied in 1992 were 0.25% versus 1.0% applicable today.

In general, it should be recommended to the Province that applying these high charges to major new Hydro generation and transmission capital assets is not appropriate so long as such charges only serve to aggravate concerns regarding Hydro's equity or reserve levels and add pressures to increase Hydro domestic rates above inflation, i.e., applying these charges to these new assets should be deferred until Hydro's debt/equity ratio has clearly rebounded to levels deemed adequate by Hydro.

The focus today is on Provincial charges on assets for the two major new projects not yet in service (Bipole III and Keeyask), given that Wuskwatim is already in service with the full related increase in taxes and charges included in the Province's revenues. In this context, and Hydro's stated concerns about financial performance over the next decade, it should be recommended to the Province that the capital tax and Debt Guarantee charge on Bipole III and Keeyask be eliminated over the next decade.

For example, the Debt Guarantee Fee in forecast 2017/18 is projected to be $153 million. If this value were fixed, rather than allowed to grow to $234 million at forecast 2021/22, this would yield an annual savings of approximately $80 million, or about 5% on rates[1]. Capital Taxes are set to grow from $93 million to $130 million over the same period. Fixing at the $93 million level would similarly yield savings, in this case $37 million, or about 3% on rates.

Aside from reference to Hydro history to show lower Provincial charges applicable to major new asset expansions, recent examples from other jurisdictions can also be instructive. Looking to two specific cases, government charges and debt guarantee terms have been established to help address capital cost pressures. In the case of Newfoundland, constructing the Muskrat Falls generation, the original federal loan guarantee from 2012 came with no fee[2] and the supplemental guarantee to address cost increases (2017) carries a guarantee fee of only 0.5%[3] on the additional guaranteed amounts (compared to Manitoba's 1%).

In British Columbia, as part of addressing the approval and financial pressures of the Site C generation project, the BC Government has clarified that the only carrying costs of the Site C project will be the cost of debt[4]. In BC, there is no debt guarantee fee[5], and the government has confirmed it expects no return on equity or dividend from the project. Earlier, in 2014, the BC Government also reduced water rental fees for the project a small degree as part of the initial provincial approval[6]. Note that unlike Manitoba Hydro, instead of fees the BC Government uses dividends as part of its cost recovery from BC Hydro, but despite this recovers less in government charges than Manitoba recovers from Manitoba Hydro as a percentage of revenue (14% versus 17% for Manitoba Hydro) or per capita ($177 versus

[1] PUB/MFR-44
[2] See pdf page 8 of https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/www/files/2012-11-29-TL-Churchill-Projects-eng.pdf term 3.7
[3] See pdf page 9 of http://www.nr.gov.nl.ca/nr/pdf/flg2_agreement_execute.pdf term 4.7.
[4] See footnote 36: http://www.sitecinquiry.com/wp-content/uploads/2017/09/DOC_90101_F1-1-BCH_submission_SiteC_Public.pdf
[5] In BC, there is a small cost recovery fee charged, which is noted to be "nominal". http://www.pub.nf.ca/applications/NLH2013GRA/files/rfi/PUB-NLH-061.pdf
[6] See http://docs.openinfo.gov.bc.ca/d7689015a_response_package_gcp-2014-00162.pdf pdf page 14.

$305 for Manitoba Hydro)[7] as shown in KPMG's Updated Financial Targets Review, Figure 5-5:

Figure 5-5: Contributions Paid to Governments from Public-Owned Canadian Power Utilities (FY2016 or FY2016/17 in annual $ millions)

	Manitoba Hydro	BC Hydro	Hydro-Quebec	NB Power	Nalcor
Dividend (1)	n/a	$259	$2,146	n/a	n/a
Debt guarantee fee	$136		$218	$32	$4.5
Water rental charges	$131	$349	$673		$4.9
Property, capital & other taxes	$135	$234	$372	$43	not available
Total	$402	$842	$3,409	$75	$9.4
Total % revenues	17%	14%	26%	4%	1%
Per Capita (rounded dollars)	*$305*	*$177*	*$409*	*$99*	*$18*

The effect of the BC Government change was to reduce the Site C cost to ratepayers by $26/MW.h (2.6 cents/kW.h), a 31% reduction to the $83/MW.h that was calculated before the change.

[7] Appendix 4.5, Updated KPMG Financial Target Review, Figure 5-5.

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PREAMBLE TO IR (IF ANY):

In summary, the lessons from the era leading up to the surge in Hydro's reserves after the mid- 1990s highlight the need for a patient and calm approach to deal with new developments rather than resort to leaps in current day rates in order to meet some specific equity level build up. As emphasized in prior Hydro submissions and PUB reviews, Hydro's past retained earnings build up has provided the strong basis needed today to move through the next stage of capital asset development. Stable long-term rate changes continue to represent the optimal approach, combined with regular update, review and readiness to adjust if and when needed to address a clear and specific new challenge.

QUESTION:

a) What is the recommended rate trajectory that would represent stable long term rate changes?

b) What is the recommended time period should be used for regular updates for assessing future rate needs?

RESPONSE:

(a)

Hydro's IFF time period has traditionally extended 20 years. Given the capital intensive nature of Hydro's operations with assets lasting 50 to over 100 years, a rate trajectory extending over at least 20 years was accepted by Hydro and the PUB during the NFAT proceeding, and appears to be a reasonable basis for representing stable long-term rate changes. Focusing on shorter time periods, such as five, ten or even fifteen years does not seem reasonable.

The specific rate trajectory that would achieve stable long-term rate changes today has been the subject of review by the PUB during the NFAT proceeding and recent GRAs. Mr. Osler and Mr. Forrest focused in their evidence on Hydro's new financial goal to recover a 25% equity level by 2026/27, and how this rate approach deviates materially from past principle and practice – and, as such, would not represent stable long-term rate changes. The specific rate trajectory to be recommended in this proceeding is addressed separately by other intervener evidence, including Mr. Bowman's evidence, and is expected not to require rate changes exceeding those approved by the Board in this and recent prior Hydro GRAs. The recommended rate trajectory could be reduced if deferrals were made on Provincial charges as reviewed in response to PUB-MIPUG-16.

(b)

Given the importance of Hydro's financial position over the next several years, annual PUB reviews are recommended for regular updates for assessing future rate changes.