Chapter:	**s. 1.1**	**Page No.:**	**3**
Topic:	**Cumulative Rate Increases between 2004-05 through 2024-25**		
Subtopic:			
Issue:	**What is an appropriate time period for the consideration of rate impacts?**		

PREAMBLE TO IR (IF ANY):

Mr. Bowman notes that:

The result, as seen in Figure 1 is cumulative actual and forecast rate increases approaching 100% over the twenty year period 2004/05 to 2023/24.

QUESTION:

a) From the perspective of a large industrial customer, why would it be appropriate to consider rate impacts between 2004/05 to 2023/24 as compared to other time periods (for example dating back to the 1990s and out to 2023/24)?

b) From a regulatory perspective, why would it be appropriate to consider rate impacts between 2004/05 to 2023/24 as compared to other time periods (for example dating back to the 1990s)?

RATIONALE FOR QUESTION:

The traditional approach of Manitoba Hydro to examining rate impacts has been to dredge up results dating back to the early 1990s which are of questionable relevance to today's consumers.

The question seeks guidance on an appropriate time frame from a consumer or regulatory perspective.

RESPONSE:

(a)

Any of the above time periods can be relevant. They are only used to illustrate the challenges faced by any operation making a capital commitment to Manitoba and then seeing how costs for matters such as power unfold going forward from the decision to invest/build/expand/increase reliance on Manitoba. However the time period from the early/mid 2000s is particularly relevant as that was a time that Manitoba was viewed as particularly competitive for industrial users, Hydro was forecasting large increases in use arising from both expansions and new operations, the Manitoba Government was actively marketing the competitiveness of Manitoba's hydro rates, and the reputation for industrial power use in Manitoba was excellent. This began to change markedly in the mid to late 2000s as Hydro began to actively discourage industrial expansion, pursue Cost of Service methods designed to shift added costs to industry, reallocate substantial export revenues to other "special" purposes in the Cost of Service study, and apply across the board increases that had no linkage to the actual costs to serve any given load. As a result, a number of expansions were known to have been put on hold and the reputation for investing in Manitoba notably changed (as can be demonstrated by the changes to Hydro's load forecast over this time, as seen in MIPUG/MH I-25ai-ii).

As reviewed in Attachment B to Mr. Bowman's evidence, MIPUG members (as major industrial power users) have consistently expressed concerns about the long-term interests of Hydro's domestic customers with respect to many items, including the need for stability and predictability of domestic rates over the long as well as short-term.

In summary, the long-term cost of power is very important to the operations and growth of industry, which takes a long-term view in making capital investment decisions.

The period from 2004/05 to 2023/24 was used for Figure 1 because it includes 10 years of actual data and 10 years of forecast data and can provide a strong indication of the current long-term trend regarding future expected rate increases for use in planning large industrial customer investment decisions.

In practical terms when making long-term planning decisions, trends seen in actual costs often tend to be just as important to review as any forecast expectations. However, absent specific information to suggest otherwise, looking backwards more than about a decade (i.e., looking

backwards today to the 1990s) or looking forward more than about a decade does not appear to offer useful information for the purposes of current long-term rate trends.

In the case of Manitoba Hydro with its reliance on capital-intensive hydro generation, actual rate increases over the past decade have been consistent and steadily above inflation regardless of the state of the economy, which is unusual for a hydro based utility. Absent other information, this decade-long experience can be a strong indicator of future cost and rate growth.

While industrial investment decisions are made for time-frames longer than 10 years, long-term forecasts beyond about a decade for costs such as electricity rates are often subjective or preliminary and cannot be relied upon, especially when capital requirements for Manitoba Hydro (which have substantial impacts on rates) past the next decade have not been explicitly confirmed.

(b)

From a regulatory perspective when assessing rates in a GRA, reviewing a 20 year period with 10 years of actual and 10 years of forecast[1] provides a balanced schematic that can dependably be used to establish trends and impacts to ratepayers.

As noted in response to (a), the period 2004/05 to 2014/15 shows the current experience for domestic customer rate impacts while also highlighting a range of external influences including: strong and recessionary economic states, high and lower flow water years, strong and weak US dollar time periods, and periods of both return and investment. The reality for domestic customers is that consistently throughout this period and regardless of external factors, actual Hydro rate increases over the past decade have been consistent and steadily above inflation.

The forecast period of ten years was used in this instance (i.e., a GRA hearing) as beyond that point cost influences driving rates, including capital plans and requirements, economic conditions and regulatory decision-making are currently too uncertain to provide a useful basis for consideration today when assessing long-term rate levels.

As noted in response to (a), and absent specific information to suggest otherwise, looking

[1] Note it is 10 years of actuals with one year of interim approved rates, not final for 2014/15 and 9 years of forecast.

backwards more than about a decade (i.e., looking backwards today to the 1990s) also does not appear to offer useful information for the purposes of current long-term rate trends.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**1.1, 1.2**	**Page No.:**	**4, 5**
Topic:	**Justification for sustaining capital expenditures**		
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Mr. Bowman indicates:

> Although capital expenditures for Conawapa have been deferred indefinitely following the recent NFAT hearing, the Application forecasts additional capital expenditures for sustaining capital resources (i.e., expenditures not included in the recent NFAT hearing evidence) and the basis for these new capital expenditures remains unclear
>
> As a result of this new evidence, Hydro indicates it has an urgent need now to improve its cash flow from operations to address its ability to fund its sustaining capital program
>
> - and suggests that the applied for rate increases can be justified in part by this new need. However, based on the evidence provided to date by Hydro, there is considerable uncertainty about the key drivers of this deterioration and a limited ability to evaluate the reasons for this rapid decline.

QUESTION:

a) Please consider the article from the Wall Street Journal titled *Utilities Profit Recipe: Spend More* which is marked as Appendix A to the information requests to Mr. Bowman. Is Mr. Bowman aware of any parallel discussion in the Canadian or North.

American context relating to the question of whether the drive for increased sustaining capital expenditures is driven entirely by reliability and risk concerns or whether there other utility objectives affecting proposed increases in sustaining capital expenditures?

b) On the final page of the article, *Utilities Profit Recipe: Spend More*, the Chair of the

New York Public Service Commission is quoted as saying:

From now on, utilities must prove that their spending will make an electric system cleaner, more efficient or stronger. Business as usual has become unaffordable.

Does Mr. Bowman have any observations relating to the changes, if any, to regulatory scrutiny of sustaining capital expenditures in other Canadian or North American jurisdictions.

c) Is Mr. Bowman familiar with the term gold plating as it is sometimes applied to the analysis of utility capital programs?

RATIONALE FOR QUESTION:

To explore possible explanations for the dramatic change in Hydro expenditures.

RESPONSE:

(a), **(b)** and **(c)**

The referenced article notes recent instances in the United States where electric utility rates have increased notably due to material increases in capital spending. It reviews possible reasons for "soaring spending" - including the fact that rate base regulated utilities can get to increase their shareholder profits through rate base growth resulting from increased capital spending. The article also notes that utilities cannot bill customers for new capital expenditures without first getting the consent of state or federal regulators.

The issues reviewed in the referenced article reflect long standing and ongoing concerns in utility regulated jurisdictions which use a rate base/rate of return model. These concerns relate to the potential conflicts in objectives between a rate base regulated electric utility and its customers with regard to the justification and prudence for new capital expenditures being recovered through rates charged to the utility's customers. The underlying concern is that proposals for increased capital spending may be driven by shareholder profit objectives rather than by reasonable and prudent utility requirements related to reliability, risk management, environmental regulation, or least cost options to supply ongoing load requirements. The term "gold-plating" as it is sometimes applied to the analysis of utility capital programs suggests spending beyond what is reasonably and prudently required with an implied objective being simply to increase profits.

In response to such concerns, regulatory scrutiny of sustaining capital expenditures tends to increase in jurisdictions when surging capital spending is seen to be a material factor driving higher rates.[1]

Manitoba Hydro is not a rate base regulated utility. It is also not typically viewed as having its capital spending driven by a shareholder profit motive such as is normally applicable to a private sector rate base regulated utility. Manitoba Hydro also does not need any PUB approval for its capital spending.

However, notwithstanding all of these distinguishing features, Manitoba Hydro cannot bill customers for new capital expenditures without first in effect getting the approval of the PUB for its cost levels overall - and enhanced regulatory scrutiny of new capital spending is justified for Manitoba Hydro as for any other electric utility when capital spending is seen to be a material factor driving higher rates.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] See response to Coalition/Bowman 3 for discussion of one such example (recent OEB reports on renewed regulatory framework for electricity distributors and subsequent new filing requirements for these utilities).

Chapter:	**1.1, 6**	**Page No.:**	**4, 20, 21**
Topic:	**Absence of meaningful hydro disclosure**		
Subtopic:			
Issue:	**Are there regulatory mechanisms to**		

PREAMBLE TO IR (IF ANY):

Mr. Bowman notes that:

Manitoba Hydro's information provided in the Application and in response to information requests from participants in this specific proceeding has failed on many key topics to provide the evidence needed to explain adequately the need and justification for the rate increases being requested at this time. (4) (emphasis added)

He also observes that:

Figure 7 compares total electric operations assets for Plan 5 with DSM Level 2 and IFF14 and indicates that IFF14 is higher than previous forecasts in all years.

Figure 8 compares total electric capital expenditures for CEF-14 to previous forecasts. The current forecast shows a material increase compared to previous forecasts.

Both CEF-13 and CEF-14 show increased sustaining capital expenditures relative to previous forecasts in the 2015 through 2020 period, and do not fully explain the increases in net plant in service and electric assets observed in Figure 6 and Figure 7.

Based on material provided to date, it is not clear how this framework has been applied or why it has led to such substantial increases in capital spending since the NFAT proceeding. Without a clear and detailed explanation, such substantial changes over such a short time period are troubling. Consequently, the Board should be concerned with whether Hydro has provided sufficient justification to merit recovery of these costs through rates at this time. (emphasis added)

QUESTION:

a) Attached and marked as Appendix B to the Information Requests for Mr. Bowman is an excerpt from the Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications. Sections 5.3 and 5.4 set out the filing requirements related to asset management and capital planning. Given the more than $500 M in proposed sustaining capital expenditures in each of the test years, does Mr. Bowman have any comment on how greater clarity in terms of filing requirements might assist in better understanding the Hydro framework for budget prioritization, asset management and sustaining capital expenditures?

b) Does Mr. Bowman have any advice on how other Canadian or North American regulators have addressed failures by utilities to demonstrably support their expenditure claims?

c) Does Mr. Bowman have any views on whether more rigourous filings by Hydro might assist the regulatory process by facilitating understanding and reducing intervenor costs?

RATIONALE FOR QUESTION:

To explore cost effective ways to address filing failures by Hydro.

RESPONSE:

(a), **(b)** and **(c)**

Please also see Coalition/Bowman-10A.

Mr. Bowman's evidence is premised on the principle that a utility applying for a rate increase has the burden to identify, and then to provide, the information required to confirm the need and justification for the requested increase, and to meet the reasonable expectations of the regulator and intervenors.[1] It is in this context that Mr. Bowman's evidence focused on Manitoba Hydro's

[1] The OEB report referenced in the IR (Appendix B) make this same point at page 19 as to the onus that falls upon the utility applicant (in the OEB document, this is a distributor utility) seeking a rate increase: "...the onus is on a distributor to provide the data, information and analysis necessary to support the capital-related costs upon which the distributor's rate proposal is based."

failure, in the Application and in response to IRs, to provide an adequate explanation of the need and justification for rate increases being requested at this time - and directed attention (as one of the related issues) to lack of clarity on why substantial increases in capital spending are now required relative to what was forecast in the recent NFAT proceeding, and specifically what changed.

Absent information to explain at any useful level the basis for the sudden and substantial increases in capital spending, it is easy to agree with the suggestion in this interrogatory that greater clarity and more rigorous filings by Hydro (and greater clarity in terms of filing requirements) with regard to its capital plans and related asset management processes would assist the regulatory process by facilitating understanding and reducing intervenor and overall process costs. Moreover, enhanced clarity should be of assistance to Manitoba Hydro in rate proceedings - in that it would assist the Board in examining the proposals. Failure by utilities to demonstrably support their expenditure claims otherwise leaves the Board with no basis to approve rate increases based on such claims.

In this context, it is also relevant to seek greater clarity with regard to the Hydro framework for budget prioritization, asset management and sustaining capital expenditure. Ultimately, however, the regulatory rate review process needs information filed by Hydro that enables the Board to assess the pacing and prioritizing of capital investments in a manner that fully considers rate impacts.

In this context, the excerpt filed with this IR (Appendix B) from Chapter 5 of the Ontario Energy Board (OEB) Filing Requirements for Electricity Transmission and Distribution Applications provides a window on how one regulator has been attempting to address capital expenditure review in a renewed way for the purpose of setting rates for electricity distribution utilities. In particular, the following are noted with regard to Appendix B:

- The excerpt is part of a set of overall new filing requirements for OEB performance based rate regulation of electricity distribution utilities in Ontario. As noted at page 1, footnote #1, "The renewed regulatory framework for electricity is a comprehensive, performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers."

- The OEB references in this regard its October 18, 2012 Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report") as the source for the March 2013 OEB report on Distribution System Plan ("DS Plan") consolidated filing requirements to document a distributor's asset management process and capital expenditure plan.
- At page 2 of Appendix B (the March 28, 2013 OEB filing), the OEB states as follows with regard to the goal for DS Plan filings in the context of performance-based rate regulation:

  "DS Plan filings must enable the Board to assess whether and how a distributor has planned to deliver value to customers. **One of the primary goals of DS Plans and by extension, hallmarks of good planning, is pacing and prioritizing capital investments in manner that considers rate impacts.** To facilitate the achievement of this goal, these filing requirements focus on the qualitative and quantitative information distributors can use to support their investment proposals that will best enable the Board to assess how a distributor has sought to control the costs and related rate impacts of proposed investments." (emphasis added)

In summary, the process followed by the OEB to develop new filing requirements for distributor utilities (and the resultant clarity in setting out these requirements) is likely indicative of the type of process and clarity goals which may be relevant to developing a renewed regulatory framework for PUB review (for rate setting purposes) of Hydro's capital plans and expenditures.[2]

However it is also important to note that the present hearing faces a unique issue of massive cost escalation for sustaining capital occurring immediately after an unprecedented review that included review of capital-related cost pressures. Today's massive cost escalation was not highlighted (or possibly known) by Hydro at the NFAT review. Today's acute issue (including the surprise factor) is no guarantee that future proceedings will face the same questions to the same degree. Any new filing requirements and/or review processes must be considered in light

[2] A recent whitepaper document prepared by Deloitte for the Canadian Electricity Association (Asset Health Indices, A utility industry necessity) reviews the requirements for Asset Health Indices and provides a view point on current usage in a sample of 15 Canadian utilities. This document notes (page 3) that in some Canadian provinces regulators are demanding detailed analysis and justification of budgets being submitted by utilities, as well as long term views about necessary maintenance and system reliability, and that implementation of Asset Health Indices is needed to meet these regulatory demands.

of possible future requirements as well as the legislative framework differences between Ontario and Manitoba (for example) plus balancing process (e.g., PUB) cost implications.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**1.2**	**Page No.:**	**7**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

The Board should recommend that Hydro retain responsibility for planning and delivering DSM programs for industrial customers but monitoring of costs and benefits of DSM programs may reasonably be undertaken by an independent entity.

QUESTION:

a) Please provide support for your conclusion that monitoring of costs and benefits of DSM programs may reasonably be undertaken by an independent entity.

b) What independent entity does Mr. Bowman contemplate and what, if any changes to the existing regulatory structure might be required to facilitate meaningful analysis?

RATIONALE FOR QUESTION:

To explore Mr. Bowman's reasons.

RESPONSE:

(a) and **(b)**

Mr. Bowman’s primary comment is in regards to industrial DSM, noting that program delivery by any entity other than Manitoba Hydro is not reasonable. This for many

reasons including (a) because industrial DSM is highly individualized and not easily operated as a program (unlike DSM for mass market customers), (b) because Hydro (by necessity) already possesses specific and commercially confidential information relevant to these operations and the customers would generally not desire added parties to have access to this information, and (c) because in many cases industrial DSM is part of decision making already and necessarily occurring within Hydro with regard to such matters as service connection sizes and this cannot be outsourced.

If there were some compelling need for a new independent DSM entity, at most the appropriate role for industrial DSM would be in monitoring programs (not design or delivery).

It is also worth noting that examples of independent DSM entities in other places may not provide an effective framework for adoption in Manitoba for any classes. To date it appears that known independent entities that handle all energy efficiency programming in other jurisdictions, as adopted in New Brunswick (EfficiencyNB) and Nova Scotia (Efficiency Nova Scotia) are now being scaled back. For example EfficiencyNB is being wound up with the programs returning to NB Power[1]; Efficiency Nova Scotia had its core funding – an electricity tax – repealed[2]. Outside of New Brunswick, no other jurisdiction that has government-owned utilities, much less a single utility for the entire jurisdiction (or a utility that combines hydro and natural gas), appears to use this type of independent implementation model. An example that is commonly cited is Vermont, which has this type of agency; however, Vermont has multiple utilities that the agency is trying to coordinate, and unlike Manitoba all are privately-owned, making energy efficiency harder to implement on a case by case basis without an authority providing overall governing direction.

[1] http://www2.gnb.ca/content/gnb/en/news/news_release.2014.10.1231.html.

[2] http://novascotia.ca/news/release/?id=20140407005 Note that Efficiency NS will continue to operate to help offset coal generated power by Nova Scotia Power. This is an outcome of NS Power being a privately owned utility, and not a Crown Corporation. The comparison is therefore not entirely relevant for Manitoba.

In any event, if an independent agency is pursued, it is imperative that this is done in a cost efficient manner as to not add to the cost of DSM programming for ratepayers, nor to undermine positive DSM metrics such as RIM. It also is critical that any such independent entity be regulated by the PUB, to ensure that any subsidizing of excessive costs, or adverse impacts on non-participating rate payers, is prevented.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**7**	**Page No.:**	**23**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Mr. Bowman states:

> Manitoba Hydro's position is that, from an overall fairness perspective, the PUB should consider the impacts of the proposed depreciation changes for rate-setting purposes as a whole rather than focusing only on the change to ELG. However, the PUB must primarily concern itself with ensuring the overall approach is principled and reasonable and results in a fair matching of cost profiles and benefits for ratepayers. From this perspective, the onus is to demonstrate that each method change separately is required for rate regulation purposes, that it **better matches regulatory rate setting concepts** and that it is to the **benefit of rate payers.** (emphasis added)

QUESTION:

a) Taking into account the principal of better matching rate setting concepts and the issue of benefit to rate payers, does Mr. Bowman have an opinion on whether ELG or ASL better meets each of these objectives? If so, please provide your opinion and supporting reasons.

RATIONALE FOR QUESTION:

It is unclear whether Mr. Bowman prefers ASL and if so, why?

RESPONSE:

(a)

In Mr. Bowman's view, the ASL method better matches regulatory rate setting concepts and better matches the distribution of costs and benefits to ratepayers over time, compared to ELG. This is particularly true for capital intensive assets such as hydro-electric generating stations and transmission lines, and regardless as to the degree of componentization (so long as componentization is sufficiently detailed to meet such standards as the FERC Uniform System of Accounts, which Manitoba Hydro's current accounts far surpass[1]). This is for the following reasons:

1. ASL results in lower depreciation costs in the early years of an asset's life compared to ELG. This is more consistent with the distribution of economic benefits of hydro-electric generation assets, which typically are low in the early years of the asset's life and increase over time.

2. ASL reduces the burden on today's ratepayers during periods of intense capital growth, compared to ELG. This is particularly relevant given that Manitoba Hydro is currently undertaking substantial development of major new hydro-electric generation and transmission assets.

3. ASL more equitably distributes the costs of these new major capital projects over time, compared to ELG.

For these reasons, ASL is used by many public sector utilities in Canada as provided in response to PUB/MIPUG-17.

For further explanation on why ASL better addresses the intergenerational equity issue please review the response to PUB/MIPUG-16.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] For example, the FERC Uniform System of Accounts has a total of eight components for all hydraulic assets for a single utility. Manitoba Hydro has more than eight accounts for each site and componentizes by site.

Chapter:	**7.1**	**Page No.:**	**24**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Mr. Bowman states:

> The highest cost assets of Manitoba Hydro are also the longest lived and if anything have an increasing economic value as they age.

QUESTION:

a) Please elaborate on the reasons for drawing this conclusion with an illustrative example to support your views.

RATIONALE FOR QUESTION:

To test the basis for Mr. Bowman's statement.

RESPONSE:

(a)

Please see the response to PUB/MIPUG-16.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**7.1**	**Page No.:**	**26**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Mr. Bowman states:

> Other utilities with gas and coal generators were initially hesitant about increased costs to dismantle as well but are finding that there is inherent value in these sites as many utilities have converted steam plants to gas without going through a massive dismantlement (i.e. they are not as costly as predicted).

QUESTION:

a) Please provide illustrative examples to support this statement.

RATIONALE FOR QUESTION:

To test the basis for Mr. Bowman's statement.

RESPONSE:

(a)

Mr. Bowman’s statement reflects in part discussions with Patricia Lee, who has more direct experience with reuse of thermal generating sites. Reuse of existing sites for major generating assets (hydro or thermal) is often preferable to returning the site to a greenfield state and constructing new assets elsewhere. The reasons for this were articulated by KPMG during a review of depreciation methods for Newfoundland and Labrador Hydro:

> When a major asset is replaced by a new asset of the same nature at the same site (rather than abandoned), site restoration or rehabilitation is not required. The existing site will still be occupied by the new asset (most likely in an upgraded or improved form). Salvage will include the removal costs of the asset that is replaced, which will normally take place as part of the construction activities related to the new asset. In most cases it would actually be quite hard to separate the costs of the two activities.
>
> In the case of negative net salvage the rationale for this treatment is the assumption that any such salvage is most likely to be offset by construction cost savings attributable to the fact that the site has been previously occupied by a similar asset.[1]

Part of the rationale for these decisions reflects the presence of transmission infrastructure, communities who have experience with the vicinity of generating stations, or existing licenses. For example, Mr. Bowman is familiar with a number of recent examples such as the recent addition of a 100 MW turbine unit by Newfoundland and Labrador Hydro at the existing Holyrood Generating Station Site. The 1,500 MW oil fired Holyrood station is scheduled to be largely decommissioned within 10 years, but despite this new generation in the form a 100 MW turbine is being installed at the same site in order to provide for reliability in the long-term.

A hydroelectric-related recent example is the redevelopment of the Bluefish hydroelectric generating station in the Northwest Territories, where an existing facility was at end-of-life and was refurbished rather than decommissioning the existing site and developing an alternative project at another location.[2]

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] 1998 KPMG Depreciation Policy Study for Newfoundland and Labrador Hydro. Provided in the response to Consumer.
Advocate Information Request CA-NLH-32 from the 2012 Depreciation Methodology Review.
http://www.pub.nf.ca/applications/NLH2012Depreciation/files/rfi/CA-NLH-032.pdf.

[2] Discussed further during the 2012/13 & 2013/14 GRA hearing by Patrick Bowman in direct testimony with Mr. Antoine Hacault, January 23, 2013, pages 535-5362.

Chapter:	**3**	**Page No.:**	**10 & 12**
Topic:	**Accounting Changes and Capitalization of Overheads**		
Subtopic:	**Capitalization of Overheads under IFRS**		
Issue:	**Appropriate Treatment for Rate Setting**		

PREAMBLE TO IR:

Mr. Bowman states:

> It is important for the PUB to consider whether or not the accounting method changes, which often increase costs in the forecast period and required rates, are appropriate and fair to use to set rates paid by domestic customers today. (page 10)
>
> It is important to ensure that expensing these costs to today's ratepayers is fair. (page 12)
>
> It is necessary (as in the past) for the Board to ensure that costs are fairly apportioned to customers based on the time periods (years) when the benefits of spending are expected to arise rather than on any suggested need to strictly follow financial reporting procedures. (page 12)

QUESTION:

a) What tests/criteria should be used PUB use to determine whether or not the proposed accounting changes with respect to the capitalization of overheads are "fair" from a regulatory and rate setting perspective?

b) What options/alternatives exist if the Board were to conclude that the capitalization of overheads as required under IFRS was not "fair" from a regulatory and rate setting perspective?

c) Are there any differences as to the options/alternatives that exist in the short-term (i.e. while IFRS transition is in a state of flux) versus over the long term?

RATIONALE FOR QUESTION:

To better understand how the Board should approach the issue regarding capitalization of overheads and the options available.

RESPONSE:

(a)

The tests for fairness of rates should reflect whether on a fully loaded or full-cost basis costs that are incurred today to provide a mix of benefits today and benefits in the future (through capital investment) are properly being tracked to each of these time periods. For example, a stores function that is required regardless as to whether capital spending is occurring, but which spends 50% of its space, time, effort, etc. on capital related items as opposed to operating related items should be allocated on a similar basis (50:50), including staff time, supervision, facility operating costs, etc.

(b) and **(c)**

Please see the response to PUB/MIPUG-9.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**4**	**Page No.:**	**14**
Topic:	**OM&A BUDGETING**		
Subtopic:	**Forecast OM&A Expense**		
Issue:	**Comparison of OM&A Forecasts**		

PREAMBLE TO IR:

Mr. Bowman states:

> forecast OM&A spending in IFF-14-1 continues to be equal to or higher to OM&A spending forecasts in IFF-12-1 until 2017/18 (pages 14, lines 3-5)

QUESTION:

a) Please clarify whether this comparison was based on OM&A costs before or after the removal of accounting changes.

RATIONALE FOR QUESTION:

To clarify the basis of the OM&A comparisons made in the Evidence.

RESPONSE:

(a)

The statement that forecast OM&A spending in IFF14-1 continues to be equal or higher to OM&A spending forecasts in IFF12-1 until 2017/18 includes strictly the OM&A items from the respective IFFs, with two exceptions: DSM and IFRS implementation date which are adjusted to make the respective IFFs consistent for these two matters. This is shown in Figure 5 of Mr. Bowman's evidence. In other words, it includes the effects of all matters that affect net income and affect ratepayers, such as accounting changes.

Specifically:

- Actual OM&A and IFF14-1 as reported in Figure 5 of the Pre-Filed Testimony includes all accounting changes (i.e. no adjustments have been made).

- Two sets of adjustments were made to IFF12-1 and IFF11-2 data. These are shown in Table 1 below.

With the adjustments to IFF11-2 and IFF12-1, the forecast amount for IFF14-1 is higher for the test years than either IFF11-2 or IFF12-1. Actual OM&A is also higher than forecast amounts in both IFF11-2 and IFF12 for the past three years.

Explanation of the two sets of adjustments is as follows:

- Originally in the 2012 GRA, IFRS changes were proposed to take effect starting in 2013/14 for IFF11-2 and then pushed a year to 2014/15 in IFF12-1. In this GRA, IFRS changes in IFF14-1 for OM&A take effect in 2015/16. To compare for these years all associated IFRS adjustments in IFF11-2 and IFF12-1 were removed in the 2013/14 and 2014/15 forecast years, commencing in 2015/16 in line with IFF14-1 and actuals.

- Originally in the 2012 GRA, Hydro proposed to expense DSM costs on an annual basis due to IFRS, as opposed to the approach for IFF14 which capitalizes DSM costs. To compare with IFF14-1 and actuals, added DSM costs to OM&A as a result of IFRS were removed from IFF11-2 and IFF12-1 in all forecast years.

Table 1: Forecast OM&A with Adjustments for Accounting Policy Changes between 2012 and 2015 GRA ($ Millions)[1]

Forecast OM&A Expense ($ Millions)	11/12	12/13	13/14	14/15	15/16	16/17	17/18
IFF11-2	398	447	532	542	548	554	571
Less Expensed DSM from Initial IFRS Accounting Policy			32	29	29	26	22
Less Implementation of IFRS for 2013/14			39	38			
IFF11-2 (IFRS changes pushed to 2016 and less DSM IFRS Changes)	398	447	461	475	519	528	549
IFF12-1		455	471	544	556	567	590
Less Expensed DSM from Initial IFRS Accounting Policy				23	22	21	20
Less Implementation of IFRS for 2014/15				40			
IFF12-1 (IFRS changes pushed to 2016 and less DSM IFRS Changes)		455	471	481	534	546	570
IFF14-1				486	542	552	557
Actuals	412	463	481				

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] OM&A as reported in IFF11-2, IFF12-1 and IFF14-1 with expensed DSM removed (which is being capitalized in IFF14) and IFRS implementation delayed until 2015/16, with accounting change data from PUB/MH I-42 from the 2012 GRA for IFF11-2 and from Exhibit MH-55 from the 2012 GRA for IFF12-1. Actuals as per PUB/MH I-9d of 2012 GRA and per Appendix 11.18 of 2015 GRA (figures do not include subsidiary amounts).

Chapter:	**6**	**Page No.:**	**22**
Topic:	**Net Plant In Service and Capital Expenditures**		
Subtopic:	**Increased Capital Spending**		
Issue:	**Justification of Capital Spending**		

PREAMBLE TO IR:

Mr. Bowman states:

Without a clear and detail explanation, substantial changes over such a short time period are troubling. (page 22)

QUESTION:

a) What additional information should Manitoba Hydro have provided in order to sufficiently justify its increased capital spending?

RATIONALE FOR QUESTION:

(a)

RESPONSE:

As reviewed in response to Coalition/Bowman 3, Mr. Bowman's evidence is premised on the principle that a utility applying for a rate increase has the burden to identify, and then to provide, the information required to confirm the need and justification for the requested increase. Accordingly, Manitoba Hydro needed to have provided the information required overall to meet this burden or responsibility.

However, this burden of responsibility ought be considered to be exceptionally high at the moment, given the recent history. In particular, Hydro and intervenors have just completed one of the most lengthy, detailed and expensive hearings in Manitoba Hydro history focused almost

entirely on rate effects of proposals for unprecedented new capital projects in light of large underlying rate pressures arising from Hydro's ongoing operation (including "normal" capital spending). The issue of compounding rate impacts was a significant topic of review. Any understatement at the NFAT of the level of normal capital spending that was expected to be required only serves to undermine the degree to which the Board could properly assess whether ratepayers could practically absorb the ambitious new major capital projects. In some cases the increases are 35% or more in a given year today compared to the NFAT filings, as shown in PUB/MIPUG I-13[1].

As a result, the key information elements needed from Hydro for this proceeding (on top of the normal requirement for meaningful analysis as to why sustaining capital spending is now so much higher than in the previous capital plan reviewed) is context for how Hydro was so unaware of these requirements at the time it filed its NFAT and what confidence it can now give these new estimates just one year later.

As reviewed in response to Coalition/Bowman-3, Chapter 5 of the Ontario Energy Board (OEB) Filing Requirements for Electricity Transmission and Distribution Applications (provided by Coalition as Appendix B to the interrogatories) provides a window on how one regulator has identified added filing requirements to address capital expenditure review in a renewed way for the purpose of setting rates for electricity utilities. As noted by the OEB, one of the primary goals of good planning in this regard is pacing and prioritizing capital investment in a manner that considers rate impacts - and Manitoba Hydro needed to have provided the additional information required to allow the Board to address this goal with regard to setting of rates (including at the NFAT). The referenced OEB document and the response to Coalition/Bowman-3 and PUB/MIPUG-14 provide additional specifics on potentially relevant filing requirements, including Asset Health Indices assessments and linkages to reliability performance.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] E.g., Table 2 in PUB/MIPUG 13 shows the NFAT level of sustaining capital spending at $384.2 million in 2020 when Keeyask comes into service – that value is not $522.4 million, a 36% increase.

Chapter:	**7**	**Page No.:**	**24**
Topic:	**Depreciation**		
Subtopic:	**Equal Life Group Depreciation Methods**		
Issue:	**Suitability for Setting Electricity Rates**		

PREAMBLE TO IR:

Mr. Bowman states:

> The Equal Life Group (ELG) approach to depreciation does not match the economic cost curve of long-lived hydroelectric generation assets, a concept imperative to setting fair rates. (page 24)
>
> In a cost-based revenue system it is important that the costs of these assets matches the intergenerational use. (page 24)

QUESTION:

a) Please explain more fully why the ELG approach to depreciation does not match the economic cost curve of long lived assets and, if possible, provide an illustrative example.

RATIONALE FOR QUESTION:

To better understand the deficiencies ascribed to the ELG approach to depreciation.

RESPONSE:

(a)

Please refer to the response to PUB/MIPUG-16 for an explanation of why the ELG approach to depreciation (compared with the ASL approach) does not match the economic cost curve of long lived hydro generation assets.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**9**	**Page No.:**	**32 & 33**
Topic:	**Curtailable Rate Program**		
Subtopic:	**Reduced CRP Load Caps for Options A and R**		
Issue:	**Benefit of Curtailable Load**		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain more fully the claim set out on page 32 (footnote #55) and page 33 (lines 19-22) that curtailable load permits Manitoba Hydro to more fully capture export market opportunities.

RATIONALE FOR QUESTION:

To better understand the claimed benefits of CRP.

RESPONSE:

(a)

In general terms, the presence of curtailable load allows Hydro to more efficiently utilize its generation resources, as less actual generation capacity is required to be held back in reserve to meet Contingency Reserve Sharing obligations. Further, Hydro has previously indicated that the presence of curtailable load increases the measured complement of capacity resources available to Hydro, which permits capacity sales and/or increased quantities of firm (capacity backed) energy sales.

As an example, Hydro noted the following in response to MIPUG/MH I-44d in the 2012/14 GRA Attachment 2, page 12:

In general terms Manitoba Hydro's objective for marketing curtailable capacity and energy is to utilize any excess in a manner that provides the greatest profits. This may involve the sale of additional short term 5 x 16 contracts (e.g. 48% capacity factor) if there is sufficient surplus energy, or the sale of peaking capacity which requires the supply of less energy during the on-peak period (e.g. 20% capacity factor).

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION: