Chapter:	**P. Bowman Direct Testimony**	**Page No.:**	**10**
Topic:	**Accounting Changes- Capitalization of Overheads**		
Subtopic:			
Issue:	**Capitalized Overhead Costs/ Regulatory Deferral Accounts**		

PREAMBLE TO IR:

IFRS IAS 16 [19] PP&E states that administrative and general overhead costs are not permitted to be capitalized to PP&E.

Interim Standard IFRS 14[85] Regulatory Deferral Accounts provides examples of the types of costs that rate regulators might allow in rate-setting decisions and that an entity might, therefore, recognise in regulatory deferral account balances including non-directly attributable overhead costs.

QUESTION:

a) Please indicate what criteria should be applied to determine which of the proposed overhead costs MH intends on expensing, to comply with IFRS requirements under IAS16 Property Plant & Equipment, should be capitalized as regulatory asset under IFRS 14.

b) Please indicate the impact on 2015/16 revenue requirement based on the proposed capitalization of costs determined in (a).

RATIONALE FOR QUESTION:

RESPONSE:

(a) and **(b)**

In preparing the pre-filed testimony, Mr. Bowman focused on the overhead components set out in the response to PUB/MH-I-73a (i.e., not focusing on those related to pension and benefits, or intangible assets). The impact of these changes totals approximately $120 million/year as shown in Table 1 of Mr. Bowman's evidence. This reflects a direct transfer from amounts that previously were capitalized (e.g., as recently as 5-6 years ago), and now are proposed to be expensed each year (though the net impact is slightly smaller than $120 million/year as the depreciation costs would be slightly higher in the latter years had some portion of these items been capitalized). Also note that this $120 million is far in excess of the $93 million that the Board was aware of at the time of Order 43-13 (page 13) when it noted "The Board will direct Manitoba Hydro to file an International Financial Reporting Standards status update at the next General Rate Application. Until such time, the Board expects Manitoba Hydro not to make any further accounting changes for rate-setting purposes."

To put this into context, $120 million is over 8% on domestic rates. In other words, compared to the systems and standards that were in place and consistently recognized by the Board as being consistent with "just and reasonable" rates (as this term is used in the Public Utilities Board Act), ratepayers now face 8% higher rates solely for the purpose of funding these amounts that were previously capitalized.

Mr. Bowman's primary concern is with providing advice to the Board in regard to fulfilling the legislative requirement that rates be just and reasonable. This is the first and foremost requirement of a GRA hearing. Having made such decision, options and choices are available to Hydro in regard to how to prepare financial statements reflecting these Board decisions. The regulator, particularly in Manitoba where the legislative framework is somewhat more limited than in many jurisdictions, must be careful about the degree to which it is dictating the utility's accounting approach. This same view was expressed by Manitoba Hydro in replying to the IASB Exposure Draft on regulatory accounting in 2009 (from CAC/MH I-22e in the 2012/14 Hydro GRA, Attachment 1):

> As identified in the cover letter to this response, Manitoba Hydro is generally supportive of the proposed standard, but would like to emphasize that management is ultimately responsible for the selection of accounting policies and the preparation of the financial statements. Certainly, the decisions of a regulator can significantly influence the economic outcomes for a regulated utility, but the scope within which the regulator can create these outcomes is limited to the regulatory framework governing the relationship between the entity and the regulator.

Mr. Bowman also notes that in that same submission, Manitoba Hydro was also supportive of the regulator being able to dictate inclusion of amounts in Property, Plant and Equipment that differ from the normal IFRSs:

> **Question 4**
>
> ***The exposure draft proposes that an entity should include in the cost of self- constructed property, plant and equipment or internally generated intangible assets used in regulated activities all the amounts included by the regulator even if those amounts would not be included in the assets' cost in accordance with other IFRSs (see paragraph 16 of the draft IFRS and paragraphs BC49–BC52 of the Basis for Conclusions). The Board concluded that this exception to the requirements of the proposed IFRS was justified on cost-benefit grounds.***
>
> ***Is this exception justified? Why or why not?***
>
> Manitoba Hydro strongly supports the exception proposed by the Board in the exposure draft. Including amounts allowed by the regulator in the cost of property, plant and equipment appropriately reflects the economic substance of regulated operations and the basis upon which rates are set.
>
> Manitoba Hydro also strongly agrees that this exception is justified on cost-benefit grounds. In addition, this exception promotes consistency in financial statement presentation for a significant aspect of a rate regulated utility's operations which will assist the users of the financial statements upon the transition to IFRS.

Mr. Bowman is not proposing a specific set of criteria to determine precisely which costs can be capitalized and which cannot. Mr. Bowman's primary conclusion regarding the above concerns is that there is ample basis for Hydro not to be granted a 3.95% rate increase, but rather that an increase more in line with inflation should be adopted.

A secondary conclusion is that Hydro may consider that some material portion of the above noted $120 million per year of costs presently targeted to be included in OM&A instead be recognized in capital via somewhere in the neighborhood of an additional "regulatory" overhead rate (perhaps 5%) being applied to capital projects in the next few years (capital from 2015-2019 being on the order of $2.1 - $3.1 billion per year in spending). This would yield an overhead treatment for ratepayers in the next few years generally consistent with the standards applied over the long-term in Manitoba and in a number of other North American utilities. It is not possible for Mr. Bowman to cite a precise impact of this change on revenue requirement, but it would be far more than sufficient to permit the recommended rate increase proposed by Mr. Bowman of 1 - 3% at this time. The following additional points are noted on this approach:

- A precise accounting for this rate could be determined by applying appropriate full cost accounting methods of which extensive information is available regarding current practice (e.g., consider the work of the Ontario Energy Board and Hydro One Networks, Inc in 2012[1] and 2013 including independent third party verification by Black and Veatch[2]).

- Mr. Bowman has previously acknowledged that some parts of the $120 million change may be appropriate to be recorded in current operations and not capitalized (e.g., in the 2012/14 GRA Mr. Bowman indicated he did not support the specific item of recapitalizing depreciation on existing common assets as part of the cost of new assets, which was a previous Hydro practice), however this is expected to be a minority of the amounts at issue.

- This approach would not lead to issues with regard to the actual accounting applied in the years prior to 2014/15 as the OM&A and capital costs for those years are now crystallized and can be retained.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2013-0416%20Dx%20Rates/Exhibit%20C/C1-05-02%20Attachment%202.pdf.
[2] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2013-0416%20Dx%20Rates/Exhibit%20C/C1-05-02%20Attachment%201.pdf.

Chapter:	**P. Bowman Direct Testimony Section 3.1**	**Page No.:**	**12**
Topic:	**Increase in OM&A due to overhead expenses**		
Subtopic:			
Issue:	**IFRS Adoption**		

PREAMBLE TO IR:

QUESTION:

a) Please elaborate on the risk to Manitoba Hydro from adopting IFRS April 1, 2015 versus April 1, 2016 with respect to IFRS 14 Regulatory Deferral Accounts.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Mr. Bowman's comments are in light of the primary focus on the requirements of the Manitoba legislation, regulatory reporting, fair rates and meaningful analysis of financial targets that fulfill the PUB's purpose (which may not in all cases be the same as readers of IFRS financial statements). In this regard, nothing IFRS related would appear to impair the PUB's ability to require that rates be set based on a set of statements deemed appropriate for regulatory purposes.

However, one reasonable (but clearly secondary) objective within the regulatory process should be to preserve a reasonable degree of comparability between Manitoba Hydro's financial reporting standards and regulatory reporting standards used by the PUB for rate-making purposes. In this regard, there are risks to this secondary objective related to the timing of IFRS conversion overall and particularly IFRS 14 adoption.

If Manitoba Hydro adopts IFRS including IFRS 14 effective April 1, 2015 there are provisions in the description of IFRS 14 that suggest Hydro may lose the ability to take advantage of certain regulatory deferrals. For example, the general concept behind IFRS 14 is that it permits the entity to continue to record regulatory assets and liabilities that existed under GAAP statements. This language suggests a need for commitment to reporting for regulatory items consistently from 2014/15 going forward. Also, in the event a future decision of the IASB transitions from IFRS 14 to a more permanent Regulatory Deferral standard, similar provisions may apply. In this regard, if the timing for such deferral is not properly adopted and carried forward, it is possible it could not be implemented at a later date.

As an example, Mr. Bowman's response to PUB/MIPUG 9 indicates that the Board may conclude that a material portion of the $120 million/year that was previously capitalized and is now proposed to be included in current year OM&A continue to be capitalized for regulatory purposes. Of this amount, $55 - $60 million/year relates to items that only begin to be expensed due to IFRS. Should the Board accept Mr. Bowman's recommendation in this hearing, it would appear that Hydro may be able to use IFRS 14 to continue to record this $55 - $60 million/year as capital in the form of a regulatory deferral (specifically identified), and that this would help maintain a degree of consistency between regulatory and financial books. However if this were not adopted in the current hearing, there is a risk this approach would not be able to later be implemented as it would not be continuing an existing practice at that time.

While this would affect the comparability of Hydro's financial statements with regulatory statements used for rate-making purposes, regardless of the standards used by Manitoba Hydro for financial reporting purposes, the PUB should require Manitoba Hydro to prepare regulatory statements for ratemaking purposes that appropriately match the costs of capital and operating expenditures with the benefits of such spending to ratepayers.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony Section 3.2**	**Page No.:**	**13 Figure 4**
Topic:	**Overhead Expenditure Adjustments**		
Subtopic:			
Issue:	**Adjusted Capital Expenditure Forecast**		

PREAMBLE TO IR:

QUESTION:

a) Please provide a table/ schedule of supporting data points for Table 4.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Please see the table below which provides data points and references to support Figure 4 from the Pre-Filed Testimony.

Additionally, the data is provided in excel format in response to MH/MIPUG-2.

To clarify the data presented, Mr. Bowman was attempting to indicate how much capital expenses should have gone down (all other things being equal) from CEF11-2 to CEF14 due to new policy changes regarding overheads (the dashed line) and to portray this in relation to the total annual impact from overheads policy changes (the dotted line). In short, CEF14 should show over $120 million/year less capital spending than would have been capitalized under the rules in place in about 2009, and between $60 and $80 million/year of this reduction is only adjustments occurring since CEF11-2. This is shown in the response to Coalition/MH II-33ab where to put CEF14 and CEF11-2 on an equal comparable footing, Hydro is required to reduce (i.e., charge to income rather than capital) between $60 and $80 million/year of spending that would have been capitalized under the rules assumed for CEF11-2.

Administrative Overhead Adjustments applied to MH11-2 Compared to Total Administrative Overhead Adjustments from CGAAP and IFRS Accounting Changes

($ Millions)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CGAAP/IFRS OH Adjustments for MH11-2 (as reported in COALITION/MH II-33a-b)	**-27**	**-64**	**-65**	**-66**	**-68**	**-69**	**-71**	**-72**	**-74**	**-75**	**-77**	**-78**
PUB/MH I-73a IFRS Changes for Administrative Overhead				-55	-55	-56	-56	-57	-57	-58	-59	-60
PUB/MH I-73a CGAAP Changes for Overhead Capitalized	-60	-61	-62	-63	-63	-64	-65	-65	-66	-66	-68	-69
Total CGAAP & IFRS Administrative Overhead Adjustments	**-60**	**-61**	**-62**	**-118**	**-118**	**-120**	**-121**	**-122**	**-123**	**-124**	**-127**	**-129**

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony -Section 5.0**	**Page No.:**	**17**
Topic:	**OM&A Budgeting**		
Subtopic:			
Issue:	**Staffing Vacancy Rate**		

PREAMBLE TO IR:

QUESTION:

a) Please provide the estimated reduction in revenue requirement for 2015/16 by utilizing the average historical vacancy rates rather than the forecast vacancy rate. Please provide supporting calculation for the analysis.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

An estimated reduction in revenue requirement for forecast years 2014/15, 2015/16 and 2016/17 using the average historical vacancy rate compared with Hydro's forecast vacancy rate results in an approximate reduction of revenue requirement in the range of $14 - $25 million per year as shown in Table 1 below. This estimate does not include any possible revenue requirement adjustments resulting from overtime, or employee benefits.

Of this amount, a significant portion would relate to vacancies in areas that would traditionally be capitalized. On overall OM&A (salaries plus other costs), in 2015/16 this percentage is approximately 39%. While there is no easily referenced precise ratio for vacancy salaries, 39% can be used as a reasonable proxy.

For perspective on magnitude, this decrease in revenue requirement for 2015/16 is material, expected to be between $10 and $15 million as shown in Table 1 below. This factor alone represents approximately 1/6 to 1/4 of the requested 3.95% rate increase of $57 million (would permit the increase to be 0.6% - 1.0% lower than requested by Hydro).

Table 1: Estimated Reduction in Revenue Requirement Using Actual Vacancy Rate vs. Hydro's Forecast Average 4.5% Vacancy Rate[1]

Row		**2014/15 Forecast**	**2015/16 Forecast**	**2016/17 Forecast**
A	Business Unit Total Avg. Salary per EFT	$77,168	$80,585	$83,129
B	Straight Time EFTs for Total Corporation	6,475	6,468	6,381
C= B*4.5%	Total Vacant Positions Based on Hydro's Average Vacancy Rate of 4.5%	291	291	287
D = A * C	Resulting Hydro Vacant Salary	$22.5 million	$23.5 million	$23.9 million
E = B*7.4% - B*9.3%	Total Vacant Positions Based on Actual Rate of 7.4% - 9.3%	479 - 602	478 - 601	472 - 593
F = A * E	Resulting Vacant Salary	$37.0 - $46.5 million	$38.5 - $48.4 million	$39.2 - $49.3 million
G = F - D	**Reduction in Salary Costs from Change in Vacancy Rate**	**$14.5 - $24.0 million**	**$15.1 -$25.0 million**	**$15.4 - $25.4 million**
H = G * 0.61	**Approximate Reduction in Revenue Requirement from Change to Vacancy Rate**	**$8.8 - $14.6 million**	**$9.2 - $15.3 million**	**$9.4 - $15.5 million**

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] Business Unit Total Average Salary per EFT from Appendix 11.25, Straight Time EFTs for Total Corporation from Appendix 5.5: OM&A Expense, page 10, Forecast Vacancy Rate of 4.5% per MIPUG/MH I-6b, Actual Vacancy Rate range of 7.4% to 9.3% per year from 2009/10 to 2014/15 from MIPUG/MH I-6c.

Chapter:	**P. Bowman Direct Testimony -Section 6.0 Figure 7**	**Page No.:**	**20**
Topic:	**Capital Expenditure**		
Subtopic:			
Issue:	**Forecast Capital Spending Changes**		

PREAMBLE TO IR:

QUESTION:

a) Please provide an analysis that identifies the main differences in CEF14 versus that presented in the NFAT.

RATIONALE FOR QUESTION:

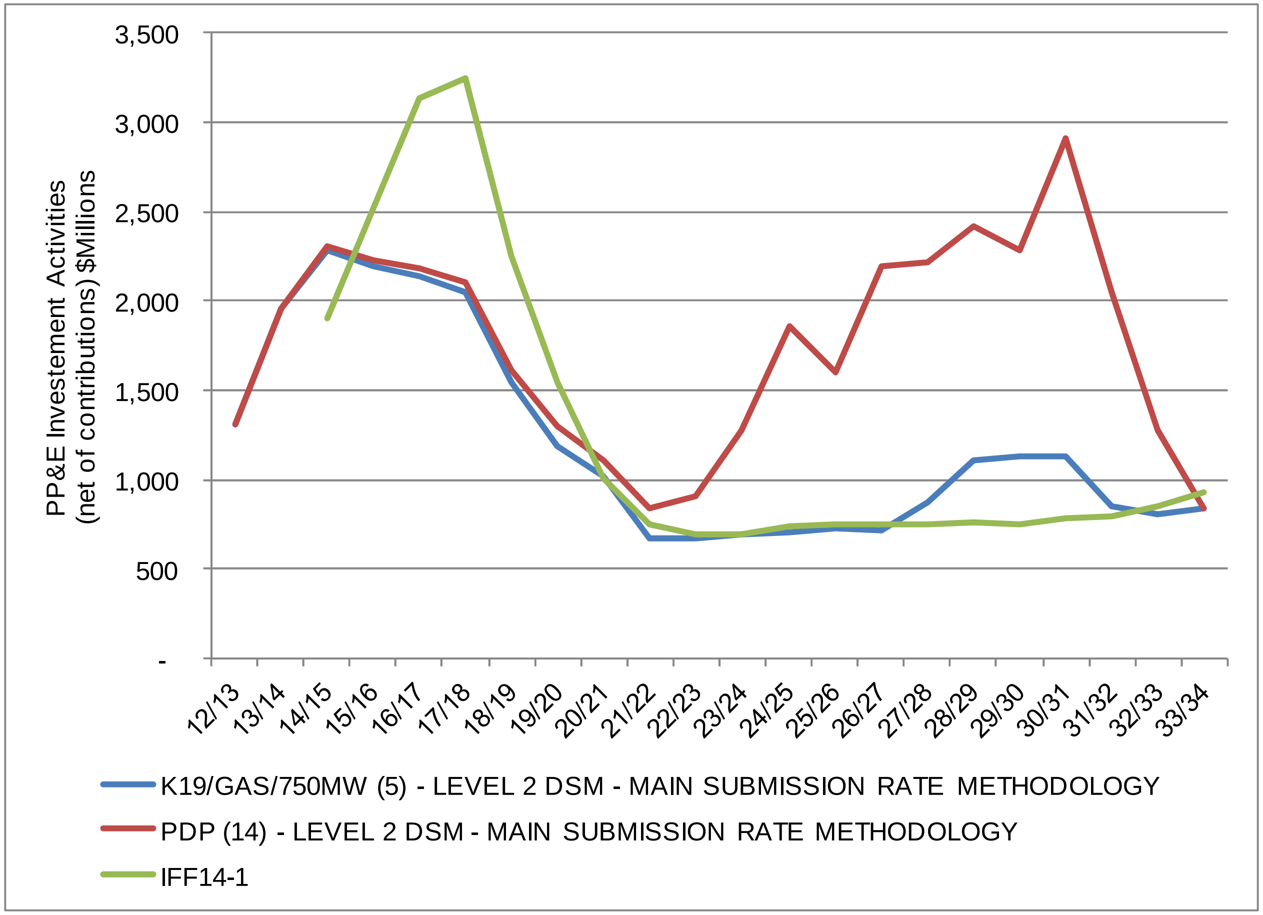
RESPONSE

(a)

Comparing the capital spending differences between CEF14 and NFAT plans is difficult because comparable capital plans were not provided for each NFAT plan.

Broadly, the total Property, Plant and Equipment contributions each year can be compared through the cash flow statements provided in Exhibit MH-104-12-1 in the NFAT review with the cash flow in IFF14 as is done in the graph (Figure 1) and Table 1 below. However, note that this includes major capital spending on Keeyask and Conawapa where relevant.

Figure 1: Comparison of PP&E Investment Activities from Cash Flow Statement ($ Millions)[1]



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[1] Data from IFF14-1 Appendix 3.3: Electric Operations (MH14) Projected Cash Flow Statement page 40-41 and Exhibit MH-104-12-1 DSM Evaluation Pro Forma Financial Statements for Level 2 DSM with main submission rate methodology for Plan 5 (most comparable to Hydro's current plans) and Plan 114 (Hydro's Preferred Development Plan at the time which includes Conawapa).

Table 1: Forecast PP&E Investment Activities from Cash Flow Statement ($ Millions)

($ Millions)	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	1,311	1,964	2,279	2,189	2,132	2,050	1,547	1,190	1,019	673	672
PDP (14) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	1,311	1,964	2,301	2,230	2,180	2,101	1,612	1,294	1,114	839	912
IFF14-1			1,900	2,518	3,134	3,244	2,253	1,550	1,010	756	698
	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34
K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	692	702	732	719	872	1,104	1,128	1,129	853	805	837
PDP (14) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	1,277	1,859	1,599	2,196	2,211	2,423	2,283	2,913	2,045	1,277	842
IFF14-1	697	744	751	752	745	762	748	787	800	846	928

From an overall spending analysis Hydro is now forecasting to spend over $3.2 billion more in the next 6 years (2014/15-2019/20) than forecasts from one year ago (K19/Gas). It should be noted that the above NFAT analysis includes the updated capital costs for Keeyask, Conawapa and BiPole-III that were reported in 2014.[2]

To review on a more detailed basis for major capital and administrative capital spending, CEF12[3] has been compared with CEF14[4] in Table 2.

The NFAT primarily used 2012 planning assumptions in the original preparation of the resource planning options (including the IFF12 and CEF12);[5] however changes were made during the review regarding Keeyask and BiPole total costs and level of DSM expenditures in the Major New Generation & Transmission spending that are not captured in CEF12. Table 2 assumes that the sustaining capital per NFAT should be basically consistent with CEF12 and therefore should be a reasonable representation of the common capital expenditures across all NFAT plans (in this case Plans 5 and 14). These values are used as a comparison to CEF14 to determine the main differences in expenditures other than Major New Generation & Transmission.

[2] From Exhibit MH-104-8 in the NFAT review, page 1.
[3] Filed in IFF12 as Appendix A in the NFAT review.
[4] Filed as Appendix 4.1 in the 2015/16 GRA, compares only electric expenditures.
[5] NFAT Business Case, August 2013, Chapter 1, Section 1.4.2.5 NFAT Submission Planning Assumptions, page 21.

Table 2: Comparison of Major Capital and Base Capital (i.e. Sustaining Capital) from NFAT (CEF12) and CEF14 ($ Millions)

($ Millions)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Major & Base Capital - Generation/Power Supply										
CEF14	132.0	131.9	132.0	132.1	132.0	131.9	132.1	134.7	137.3	140.1
CEF12	178.5	180.7	166.1	142.9	191.2	126.9	181.4	161.1	192.5	185.7
Difference	**- 46.5**	**- 48.8**	**- 34.1**	**- 10.8**	**- 59.2**	**5.0**	**- 49.3**	**- 26.4**	**- 55.2**	**- 45.6**
Major & Base Capital - Transmission										
CEF14	125.0	125.0	125.0	124.9	125.1	125.0	150.0	150.0	149.9	150.0
CEF12	148.9	124.0	67.5	39.2	42.4	45.3	49.3	72.5	93.0	106.4
Difference	**- 23.9**	**1.0**	**57.5**	**85.7**	**82.7**	**79.7**	**100.7**	**77.5**	**56.9**	**43.6**
Major & Base Capital - Customer Service & Distribution										
CEF14	235.5	240.9	268.3	206.0	205.9	206.0	206.0	210.1	214.3	218.6
CEF12	185.8	175.1	142.8	144.7	147.5	150.5	153.5	187.1	207.6	221.7
Difference	**49.7**	**65.8**	**125.5**	**61.3**	**58.4**	**55.5**	**52.5**	**23.0**	**6.7**	**- 3.1**
Customer Care & Marketing, Human Resources, Finance & Administration										
CEF14	78.4	79.2	59.3	59.3	59.4	59.5	59.6	59.9	61.1	62.3
CEF12	61.3	60.1	60.2	61.3	61.0	61.5	58.6	59.6	60.6	61.7
Difference	**17.1**	**19.1**	**- 0.9**	**- 2.0**	**- 1.6**	**- 2.0**	**1.0**	**0.3**	**0.5**	**0.6**
Total Major & Base Capital & Administrative										
CEF14	570.90	577.00	584.60	522.30	522.40	522.40	547.70	554.70	562.60	571.00
CEF12	574.50	539.90	436.60	388.10	442.10	384.20	442.80	480.30	553.70	575.50
Difference	**- 3.60**	**37.10**	**148.00**	**134.20**	**80.30**	**138.20**	**104.90**	**74.40**	**8.90**	**- 4.50**

In summary, Table 2 shows an increase for CEF14 compared with CEF12 (excluding Major New Generation and Transmission) of $534.2 million in the first six years (2015-2020), and of $717.9 million by 2023/24. The following analysis examines changes within each category in Table 2. However, within the first three of these categories, available data makes it difficult to compare all separate cost items between the two forecasts because CEF14 now lumps most costs in each category under a poorly enumerated "Base Capital" heading.

For **Major & Base Capital - Generation/Power Supply and Transmission**, these two categories must be assessed together as it is clear that HVDC work has changed classification between the two CEFs. The total impact is an increase in planned spending of nearly $200 million by 2024.

For **Major & Base Capital – Customer Service & Distribution** spending, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $416.2 million by 2020 and $495.3 million by 2024. However, given that the majority of spending is reported in “Base Capital” for CEF14 and in “Customer Service & Distribution Domestic” for CEF12, it’s not easy to analyze the cost differential based on Hydro’s filings to date or to understand a rationale for these increases since the NFAT, notwithstanding Hydro's list of construction works causing increases in the test years provided in PUB/MH I-18e.

For **Customer Care & Marketing, Human Resources, Finance & Administration**, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $29.7 million by 2020 and $32.1 million by 2024.

In general, the use in CEF14 of "Base Capital" as a summary grouping for all expenditures with a forecast of less than $50 million[6] adds a barrier to full review of the key changes since CEF12 (which reports all major capital individually).

Table 3 below attempts to compare Base Capital spending in CEF14 with CEF12 by summing all major capital projects under the $50 million total project spending threshold in CEF12 and the domestic expenditures for each of the first three major capital categories.

Table 3: Comparison of Capital Spending on Projects less than $50 Million or 'Base Capital' ($ Million)

($ Millions)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Generation/Power Supply Base Capital										
CEF14	98.9	101.6	71	55.7	77.2	72.7	118.1	97.8	110.7	98.7
CEF12	101.2	86.3	69.6	42.6	34.5	24.9	24.5	29.5	30.6	28.4
Difference	**-2.3**	**15.3**	**1.4**	**13.1**	**42.7**	**47.8**	**93.6**	**68.3**	**80.1**	**70.3**
Transmission Base Capital										
CEF14	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63	128.2
CEF12	90.4	72.3	47.3	39.2	42.4	45.3	49.3	37.3	38	38.8
Difference	**-17.2**	**-15**	**21**	**55.6**	**42.4**	**30.8**	**17.2**	**27.4**	**25**	**89.4**
Customer Service & Distribution Base Capital										
CEF14	197	182.6	209.6	160.7	173	193.3	206	210.1	214.3	218.6
CEF12	165	152.8	142.4	144.7	147.5	150.5	153.5	156.6	159.7	162.9
Difference	**32**	**29.8**	**67.2**	**16**	**25.5**	**42.8**	**52.5**	**53.5**	**54.6**	**55.7**
Total Base Capital										
CEF14	369.1	341.5	348.9	311.2	335	342.1	390.6	372.6	388	445.5
CEF12	356.6	311.4	259.3	226.5	224.4	220.7	227.3	223.4	228.3	230.1
Difference	**12.5**	**30.1**	**89.6**	**84.7**	**110.6**	**121.4**	**163.3**	**149.2**	**159.7**	**215.4**

From the comparison of the above "Base Capital" forecasts it appears that Hydro has consistently increased expenditures or number of smaller projects with total budgets less than $50 million across all departments.

In summary, Table 3 shows an increase for CEF14 compared with CEF12 for the defined "Base Capital" (focused on items with costs under $50 million) of $448.9 million in the first six years

[6] As explained in PUB/MH I-18a.

(2015-2020), and of $1,136.5 million by 2023/24. Increases in this "Base Case" cost grouping as evaluated in Table 3 are spread over each major category:

- For **Base Capital - Generation/Power Supply**, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $118.0 million by 2020 and $430.3 million by 2024.

- For **Base Capital – Transmission**, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $117.6 million by 2020 and $276.6 million by 2024.

- For **Base Capital – Customer Service & Distribution** spending, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $213.3 million by 2020 and $429.6 million by 2024.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony Section 6**	**Page No.:**	**21**
Topic:	**Evaluation and prioritization of capital expenditures**		
Subtopic:			
Issue:	**Asset Condition Assessment Reporting**		

PREAMBLE TO IR:

QUESTION:

a) Please provide MIPUG's comments on the appropriateness of the asset condition assessment reporting to date.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Mr. Bowman does not take a position on the appropriateness of the asset condition assessment reporting done by Hydro to date, other than to note that the use of asset condition reporting within Hydro has not assisted in assessing the justification for currently proposed sustaining capital expenditures in light of similar but much lower spending projections developed by Hydro within the past few years (including as part of the NFAT review – See PUB/MIPUG-13). The general purpose of such reports is typically to provide a basis for rational and predictable planning into the future regarding replacements and reinvestment, not to cause massive shifts in forecasts.

Mr. Bowman is also concerned about the definition used for "Expected Life" being defined as the "typical life span of an asset" while noting that "(u)nder favorable operating environments, the asset may exceed its typical life span" as if this concept is an exception or unusual situation. The concept of "typical" does not appear to be consistent with the concept of a "mean" or other statistical metric. Contrast must be drawn to the concept of "service lives" as used in the Gannett Fleming depreciation report, which presumes a distribution of many assets retiring well before, and many well after the service life value. Comparing the values used for lives in the Asset Condition Assessment and the Gannett Fleming report show significant differences. For example, HVDC transformers are stated in the Asset Condition Assessment to have an Expected Life of 40 - 70 years, while all HVDC equipment in the Gannett Fleming study is classified in ranges from 25 - 36 year Service Life. Other components differ in the opposite direction.

For the purposes of analyzing the justification for Hydro's forecast capital expenditures Mr. Bowman did not review the contents of Appendix 4.2: Asset Condition Assessment Report in any significant detail, predominantly since Mr. Bowman is not an engineer by trade and therefore does not try to establish or analyze the link between given information on the current engineering health of specific assets and capital spending levels.

As a regulatory tool, asset condition assessments can be somewhat difficult to use as the primary source to determine whether overall sustaining capital spending levels are reasonable. As an example of this, when some regulated jurisdictions have moved to forms of performance based ratemaking, the regulator's primary focus for ensuring the utility is not under investing in capital is metrics related to reliability (ensuring no decline for customers) or matters such as safety (no increase in accidents) rather than engineering assessments of asset condition, per se. Hydro provides some limited such reporting at pages 5 - 6 of the Asset Condition Assessment report, but does not provide any linkages or extension of this information throughout the remainder of the document (for example Hydro does not seem to address in the report what is causing increases in Generation Forced Outage Rates and whether or not it correlated to the same assets Hydro indicates are in poor or very poor condition).

Please also see responses to Coalition/Bowman-3 and Coalition/Bowman-10A for additional perspectives reflecting other regulatory related reports.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony Section 7**	**Page No.:**	**23**
Topic:	**Depreciation & Amortization**		
Subtopic:			
Issue:	**Recovery of Surplus Book Accumulated Depreciation**		

PREAMBLE TO IR:

QUESTION:

a) Please provide recommendation(s) on how to treat the current accumulated depreciation surplus.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Mr. Bowman recognizes that there are multiple options for how accumulated depreciation surpluses (or “reserve imbalance” as this term is used by Patricia Lee) can be addressed. For the purposes of this proceeding, Hydro has proposed that the surplus in effect be amortized over the average remaining life of the asset class, subject to adjustment in future depreciation studies.

Mr. Bowman has previously indicated some concern with the net effect of this proposal, for example (using updated numbers):

1) This approach leads to a very modest reserve surplus drawdown in the initial years (i.e., under ELG the surplus is $602 million and only $16.4 million of this is amortized in the

first year[1], about 2.7% or about 1/37th). Under ASL without net salvage the accumulated surplus is over $1 billion.[2]

2) In the case of Wuskwatim, the ELG reserve surplus is already $4.3 million[3] despite this asset being only a few years old, and Hydro's proposal is to amortize this amount by only $0.075 million in the first year (only 1.75% or 1/57th) despite this surplus entirely arising from the current generation of ratepayers. Under ASL without net salvage the surplus is $10 million.[4]

In the end, however, in light of the other issues and recommendations highlighted in the Pre-Filed Testimony, Mr. Bowman does not take issue with the proposal by Hydro to use remaining life due to practical reasons of rate/cost stability.

Despite the above, Mr. Bowman considers it important for the Board to recognize that the proposed approach nevertheless serves to extend the imbalance for many decades. A valid alternative view is that this surplus already exists and is in itself a form of retained earnings that could be amortized and added to the reported retained earnings on Hydro's balance sheet in the current year, as has happened in many regulatory proceedings. Were this to be the approach adopted, Hydro's balance sheet would indicate the full strength of the retained earnings/reserves built up by ratepayers over the decades and underline the significant strength of Hydro's operation to help absorb potential future risks without above-inflation rate increases today.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] MIPUG/MH I-20b.
[2] MIPUG/MH I-22b, page 20.
[3] MIPUG/MH I-20c.
[4] MIPUG/MH- I-22b, page 22.

Chapter:	**P. Bowman Direct Testimony Section 7**	**Page No.:**	**24**
Topic:	**Depreciation & Amortization**		
Subtopic:			
Issue:	**ELG Depreciation**		

PREAMBLE TO IR:

QUESTION:

a) Please elaborate on how MH's long-lived assets increase in economic value with time and why utilization of ELG causes intergenerational issues.

b) Does the use of ASL address intergenerational issues? Please elaborate.

RATIONALE FOR QUESTION:

RESPONSE:

(a) and **(b)**

Manitoba Hydro's hydro-electric generation stations are the highest cost assets in Manitoba Hydro's system.[1] Hydro-electric generation stations also have the longest expected service lives.[2]

The economic value of long-lived hydro-electric generation assets in particular tend to increase over the life of the asset. This results from several factors, including:

- The capital intensive nature of the long-lived asset, i.e., compared to other sources of generation, hydro-electric generation assets require minimal ongoing operating costs and do not need to address most replacement issues for a very long time period.

[1] As indicated in Table 1 beginning on page 17 of Appendix 5.6 of the Application.
[2] As indicated on pages 7-14 of Appendix 5.6 of the Application.

- Based on past experience, the economic value in the market and to consumers of the electricity provided by the stations tends to increase over the life of the asset (due to inflation impacts at a minimum, for example, on other marginal sources of new generation); in contrast, the annual costs for the hydro generation decline over the economic life due to its capital intensity when using any straight-line depreciation method. The net result is an increase in economic value to ratepayers of the hydro generation asset over its economic life (i.e., the gap between costs and value continues to grow).

- The above impacts are enhanced to the extent that a hydro generation asset is restored and renewed at the end of its economic life rather than abandoned or removed due to obsolescence or lack of any ongoing market value. The likelihood of such restoration for many hydro generation assets (and consistently for most large hydro stations) is an indication of the lack of threat of technological obsolesce during as well as after the asset's long economic life.

An example of some of these factors is provided by the Wuskwatim Power Limited Partnership, which is projected to have operating losses until approximately 2022. Thereafter, positive net income is expected to grow over time. The table below summarizes forecast revenue, expenses and net income at five year intervals based on information provided by Manitoba Hydro. As illustrated in the table, revenues are anticipated to grow over time, while expenses generally decrease in 2025 and beyond, largely as a result of reduced finance expense. This distribution of costs and benefits is consistent with a durable asset that is capital intensive with relatively low operating costs.

Wuskwatim Power Limited Partnership Projected Operating Statement (Millions of dollars)[3]

	2015	2020	2025	2030
Revenue	41	111	134	135
Expenses	119	123	117	103
Net Income	(77)	(13)	17	32

For the purposes of rate regulation ASL, when compared with ELG, helps to partially address intergenerational issues. There are a multitude of methods which better address these issues and lie beyond ASL on the spectrum of potential depreciation methods, such a sinking fund methods or methods based on revenues, but these are not being recommended today by Mr. Bowman and despite their preferential economic profile for hydro generation assets, have fallen out of common use.

ASL helps to somewhat alleviate the risk of over collecting depreciation expense in any year (particularly early years) for such long-lived assets by applying a uniform calculation that remains generally consistent across all years of an asset's expected life. In this manner it mitigates intergenerational cost issues that are apparent in the ELG approach to depreciation for such assets. This is demonstrated by the following considerations:

- As described in the evidence of Patricia Lee, one reason for using ELG is when the risk exists that the asset will not reach the end of its useful life due to technological or other advancements in the field rendering the asset unusable. ELG's method of prioritizing collection or higher forecast retirement in early years can be justified as appropriate if this risk is apparent (discussed further in Patricia Lee's Pre-Filed Testimony). However, Hydro's long-lived hydro generation asset base is generally not subject to risks of technological advancements causing early retirement. Absent such a risk, ASL properly assigns the value of Hydro's assets at all ages of life to ratepayers where ELG would over apply costs in the early years of an asset's life, effectively causing near-term ratepayers to subsidize the costs of longer-term ratepayers.

[3] Figures taken from pages 2 and 3 of 2015/16 General Rate Application, Appendix 11.6.

- The inherent value and level of use in Hydro’s assets does not deplete drastically with time but instead systematically endures with the aid of scheduled maintenance and overhauls. Therefore it is reasonable to assume costs can be recovered over the forecast useful life as it can be assumed that Manitoba Hydro will maintain the asset over this period of time, especially for the hydroelectric generation and transmission assets. This is also demonstrated in the life experiences to date of hydroelectric generation and transmission assets, and from Gannett Fleming’s jurisdictional comparison of assets used as rationale to elongate the lives of Hydro’s asset base in the 2010 and 2014 depreciation studies. As a result of these considerations, from a rate regulation stand point ASL somewhat better matches the intergenerational use of these long-lived assets than ELG, where there is a reasonable expectation that the assets will exist across generations. Any decrease in value of these assets is more than accounted for under the expected retirements in ASL, and therefore there is no regulatory requirement to expedite the collection of depreciation costs for these assets.

- The Hydro asset costs are known. With large hydroelectric generation and transmission assets the majority of costs occur upfront, not later over the asset's life. As there is minimal risk for ratepayers that unplanned costs will arise over the life of the asset it is not required to over collect depreciation in the early or later years of the assets planned life. In this way, ASL does help alleviate any intergenerational issues that would otherwise occur with ELG.

- Inflationary increases in value of the hydroelectric asset outputs are somewhat better represented in ASL than in ELG. The benefits of hydroelectric produced unit of power (in a cents/Kw.h metric) provide ratepayers more value towards the latter part of a hydroelectric assets life than at the beginning. In this sense ASL, or sinking-fund type methods (similar to what Newfoundland & Labrador Hydro used to employ which even further lowers the depreciation expense in the early years of an assets life than ASL, and further increases the depreciation expense in the later years of an assets life) better matches the benefit seen by ratepayers with the costs over the asset's life.

- Due to continual replacement and additions to discrete parts of a utility’s asset base (e.g., addition of Keeyask), the promise of ELG providing higher depreciation expense early on in exchange for lower depreciation expense later does not play out in practical terms, since the assets that may have transitioned to the older, lower depreciation part of their life curve become dwarfed by new modern priced assets early in their life curve. The end result is that an ELG approach with a hydro-based utility such as Manitoba Hydro (where ongoing hydro generation expansion can still occur) leads to ratepayers continuing to pay higher rates each and every year in exchange for no relief at any point in the future so long as any new hydro or transmission development or re-development is occurring. In different words, this higher cost profile with ELG is simply matched by a higher cash generation for the utility perpetually, which is one key reason that ELG is preferred by many utilities particularly private-sector firms. In this regard ELG versus ASL for a utility such as Manitoba Hydro is not an intergenerational issue whatsoever in any normal sense of such terms, as the ELG approach in this instance provides no "trade-off" where lower costs are captured by customers in some defined future in return for higher costs today.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony Section 7.1**	**Page No.:**	**25 Line 8**
Topic:	**Depreciation Methodology for Peer Hydro Electric Utilities**		
Subtopic:			
Issue:	**Peer Utility Depreciation Practices**		

PREAMBLE TO IR:

QUESTION:

a) Please provide a listing of Peer Canadian hydroelectric generation companies that utilized ASL for depreciation purposes.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Mr. Bowman does not maintain a comprehensive list of utilities on a routine basis. For the purposes of this response, Mr. Bowman notes that the following table was originally provided in the 2012 Pre-Filed Testimony of Patrick Bowman. It has been updated to present day for the purposes of this response.

Also note the following incorrect information filed by Hydro in this proceeding:

- In response to MIPUG/MH II-7, Hydro (Gannet Fleming) incorrectly states that Newfoundland & Labrador Hydro uses ELG, when the utility actually uses ASL as outlined in the Board of Commissioners of Public Utilities Order P.U. 40 (2012) at the culmination of the 2012 Depreciation Methodology review, link provided below.

- In response to PUB/MH I-42b, Hydro (Gannett Fleming) incorrectly states that Qulliq Energy Corporation (formerly Nunavut Power) uses ELG. This is not correct as the utility uses the ASL method as shown in the QEC 2010 GRA[1]

Table 1: Depreciation Methods for Crown-Owned Canadian Utilities

Utility	Depreciation Expense Calculation Method	Study Date
BC Hydro	Average Service Life Method[2]	Gannett Fleming in 2006
BC Transmission Corporation	Average Service Life Method[3]	Gannett Fleming in 2005
Newfoundland and Labrador Hydro	Average Service Life Method[4]	Gannett Fleming in 2011
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 2012
FortisBC	Average Service Life Method[9]	Gannett Fleming in 2011
Ontario Power Generation	Average Service Life Method[10]	Gannett Fleming in 2013
Nova Scotia Power	Average Service Life Method[11]	Gannett Fleming in 2010
Hydro One	Average Service Life Method[12]	Foster Associates 2011

[1] http://www.qec.nu.ca/home/index.php?option=com_docman&task=doc_download&gid=542 at page 183 of the pdf document.

[2] BC Hydro and Power Authority F2012 - 2014 Revenue Requirements Application; Appendix G: Gannett Fleming Report on IFRS Componentization. Page 8-11 (March 1, 2011). http://www.bcuc.com/Documents/Proceedings/2011/DOC_27065_B-1_BCHydro_F12_F14-RR-application.pdf.

[3] British Columbia Transmission Corporation Transmission Revenue Requirement Application. BCUC Information Request 1.63 (July 4, 2006). http://transmission.bchydro.com/nr/rdonlyres/c18a2158-e202-464a-8613-6e474d0c33df/0/bcucir1masterdocument4july2006.pdf.

[4] Newfoundland and Labrador Board of Commissioners of Public Utilities, P.U.40 (2012). Page 4. (December 31, 2012). http://www.pub.nf.ca/applications/NLH2012Depreciation/files/order/pu40-2012.pdf.

[5] SaskPower 2014, 2015, 2016 Rate Application. Section 3.2.1.2: Depreciation & Amortization. Page 31 (October 2013) http://www.saskpower.com/wp-content/uploads/2014-15-16_rate_application.pdf.

[6] Yukon Energy Corporation, 2012 General Rate Application. Tab 10: Depreciation Study by KPMG. Page 10-7 (April, 2012). 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. (September 2010). http://www.qec.nu.ca/home/index.php?option=com_content&task=view&id=175&Itemid=0.

[8] Northwest Territories Power Corporation, 2012/13 and 2013/14 General Rate Application. Page 3-13 and Appendix A-2. (March 2012).

[9] FortisBC Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan. Appendix J 2011 Depreciation Study. Page 2 of 167. (June 6, 2011). http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBC%20-%202012%20and%202013%20Revenue%20Requirements%20Application%20-%2030Jun11.pdf.

[10] Ontario Power Generation, Assessment of Regulated Asset Depreciation Rates and Generating Station Lives. (November 2013). http://www.opg.com/about/regulatory-affairs/Documents/2014-2015/F5-03-01%20Depreciation%20Study_20131205.pdf.

[11] Nova Scotia Utility and Review Board, NAUARB-NSPI-P-891, http://nsuarb.novascotia.ca/sites/default/files/documents/electricityarchive/depreciation.pdf.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[12] Hydro One, 2011 Depreciation Rate Review, Ontario Energy Board EB-2012-0031, Exhibit C1-8-1, Attachment 1. Page 3. The Ontario Energy Board accepted the costs flowing from the depreciation review for the purpose of supporting transmission rates in the test year. 2014 Rate Order. January 9, 2014. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2012-0031&sortd1=rs_dateregistered&rows=200.

Chapter:	**P. Bowman Direct Testimony Section 8.0**	**Page No.:**	**27**
Topic:	**DSM Spending**		
Subtopic:			
Issue:	**Demand Side Management**		

PREAMBLE TO IR:

QUESTION:

a) Please indicate the revenue requirement impact of the incremental higher DSM spending on 2015/16.

RATIONALE FOR QUESTION:

To understand the revenue requirement impact of recommendation to not include in rates.

RESPONSE:

(a)

For the test years, the effect of higher DSM spending as it impacts revenue requirement is the annualized amounts of incremental DSM spending for both the 2014/15 and 2015/16 forecast years. For 2014/15 the incremental DSM spending increase (compared with previous forecasts in MH12 and MH13 for the same year) is $27 million[1], and for 2015/16 is $34 million.[2]

For the 2015/16 forecast year the immediate revenue requirement (income statement) impacts from this added spending will be modest but not immaterial, perhaps $2 - 3 million per year depending on the specific amortization rate used for each program and DSM administrative costs. In the context of the 3.95% rate increase which generates slightly under $60 million/year

[1] $52 million planned spending in MH14 versus $25 million planned spending in MH13 and MH12 as shown in COALITION/MH I-19g.
[2] $59 million planned spending in MH14 versus $25 million planned spending in MH13 as shown in COALITION/MH I-19g.

in revenues, this would likely comprise about 5% of the specific single year revenue impacts, of about 0.2% on rates (i.e., the difference between a 3.75% and a 3.95% increase).

However, in respect to the current rate application, Hydro is requesting rate increases in 2014/15 and 2015/16 in part to alleviate deterioration in longer-term financial targets over the next five years and beyond. While the increased DSM spending will have benefits to the revenue requirement in the long-term (as the marginal benefit values used in assessing DSM climb with the expected increase in export market prices), over the five year time frame the expenditures will start to compound with relatively little offsetting added export revenues and substantial lost domestic revenue. This is expected to adversely impact financial targets over this period (including net income) which is presently being identified as a justification for higher rates throughout the current and coming years. With the available data and the Hydro claims of confidentiality regarding calculation of the marginal benefit value; it is not possible to estimate this effect with any precision. Mr. Bowman is not recommending any single one-to-one ratio of rate increase reduction calculated in this manner. This item is only highlighted in the context of one item that helps support the conclusion that a rate increase above the range of inflation (of 1% to 3% a year) cannot be justified at this time.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony Section 8.0**	**Page No.:**	**28**
Topic:	**DSM Spending**		
Subtopic:			
Issue:	**Demand Side Management**		

PREAMBLE TO IR:

QUESTION:

a) Please indicate the order of magnitude of the overstatement of potential DSM benefits due to domestic revenue losses.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

The order of magnitude of the overstatement of potential DSM benefits due to domestic revenue losses is substantial totalling between 4 - 8 cents/kW.h for each kW.h of sales reduced depending on the class participating in the DSM program.

It is generally accepted that domestic ratepayers will pay for all of Manitoba Hydro's costs that are not recovered through export sales. Therefore, ratepayers pay for the costs of DSM programs and benefit from utility marginal benefits (including primarily increased export sales, but also decreased costs for imports and fuel, etc.).

The issue with many of Hydro's current primary DSM metrics (including the PACT as Hydro narrowly applies this metric, TRC and LUC) is that the calculations completely ignore the foregone domestic revenue that occurs with increased participation in energy efficiency programs (shown in Appendix 6.1 as a DSM Reduction in revenues of approximately $26.5 million for 2015/16 at Hydro's proposed rates). The RIM test does include this amount.

This foregone domestic revenue can be a substantial cost in relation to the financial benefits of a project, and can also greatly change the overall composition of benefits and costs especially between rate classes.

An example of the mathematics can be shown using the Residential Conservation Rates program, per MIPUG/MH I-3c. It is important to recognize, however, that this program is not a traditional DSM program. Although this program shows challenging DSM metrics, the use of conservation or inclining rates for residential customers is often advisable under normal rate design criteria and as a result may well be proper for Hydro to pursue. However, were it solely a DSM program, the below values indicate the issues for customers:

- Hydro's present value of utility marginal benefits from this program is forecast at approximately $117 million. However, given what is known about the current state of export markets and Hydro's expectations of strong export price growth in the future, this is likely heavily loaded to future time periods. (call this variable "A")

- The present value of domestic revenue loss from this program is forecast at approximately $140 million. Assuming customers would in many cases respond relatively quickly to new rate structures, and that present values are typically dominated by effects in the first few years (when discounting is at its lowest), this negative impact on Hydro's ability to recover its costs is expected to be heavily skewed to more current times than to many years in the future. ("B")

- The present value of administration costs for this program are approximately $13 million. ("C")

- The present value of kW.h saved under the program is not presently available ("D")

- Calculating three DSM metrics indicates the following:

  - Under the RIM test, the benefits to the system are divided by the net added costs or lost revenues to the system, as follows: A / (B + C), or a RIM of 0.8[1]. This indicates that when customers participate in this program, the benefits do not cover the costs and other ratepayers rates will need to rise. The RIM test tells

[1] RIM = 0.8 = $116,989,635 / ($12,637,996 + $139,671,836) from MIPUG/MH I-3c.

nothing about how any given customer might be affected (e.g., participants versus non-participants, residential versus other classes), that can only be determined from Cost of Service analysis. But it does indicate that overall rates for other customers will need to be higher as a result of this program.

- o Under the PACT test as applied by Hydro, a ratio is calculated and for this program is considered very positive as it only considers benefits divided by out-of-pocket costs. In this case A / C. This yields the ratio of 9.3[2].

- o In a well-constructed PACT type of test, the lost revenue will be included in the consideration, and the entire result can be converted to a levelized cents/kW.h value that can be compared to other sources of power available to the utility. The formula for such a consideration is the net costs to the utility of the power divided by the present value of kW.h provided, as follows: (B + C) / D[3]. This cannot be calculated at the present time as the value for D is unavailable.

- Not including the present value of foregone revenues is the difference between Hydro's calculated RIM and PACT metrics and results in a program that goes from being uneconomic to a PACT metric with a higher and therefore more competitively beneficial benefit-cost ratio

In order to avoid this misrepresentation, it's Mr. Bowman's position that every DSM program should be assessed against the above tests (including RIM) to understand the profile of the program and its effects on other ratepayers, to ensure good information regarding cross-subsidization is available. For most programs, a RIM greater than 1.0 would tend to confirm that there is a basis for a possible win-win situation for the participating customer (who benefits from a lower energy bill) and the non-participating customer (who benefits in terms of lower utility bills by not subsidizing the DSM program) (however, in this situation the costs and benefits can still be allocated badly leading to adverse impacts on some customer and major benefits to others, so a RIM > 1.0 is not a guarantee of win-win). The information on overall cost to the utility (including lost revenues) can also be compared to other possible sources of power, such as Conawapa, or wind to determine whether DSM is the best option.

[2] PACT = 9.3 = $116,989,635 / $12,637,996 from MIPUG/MH I-3c.

[3] [Or alternatively the marginal benefits can be included to determine whether each kW.h is a net benefit or a net cost to the utility: (B + C – A) / D which in this case would be a negative value].

Not accounting for this lost revenue has a different effect for each DSM program, but for all intents and purposes can result in a substantial overstatement of benefits (or understatement of total costs).

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

Chapter:	**P. Bowman Direct Testimony Section 9.0**	**Page No.:**	**33 Lines 26-31**
Topic:	**Curtailable Rate Program**		
Subtopic:			
Issue:	**Proposed Changes to the CRP**		

PREAMBLE TO IR:

QUESTION:

a) Please indicate whether the CRP program should be expanded from its current form.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

It is important to first clarify what is meant by "current form". The current CRP is as follows (per PUB Order 43-13):

- Option A and C capped at 230 MW, with an added interim cap of 180 MW (or as low as 150 MW if the Option C customer ceases participation). Hydro is also proposing to eliminate Option C.

- Option R capped at 100 MW, with an added interim cap of 50 MW

Mr. Bowman's submission is that the Curtailable Rate Program (CRP) should remain for the present time at current fixed cap levels prior to the addition of the lower interim caps in Order 43-13 (i.e., at 100 MW for Option R and 230 MW for Option A). Mr. Bowman does not take issue with the proposal to eliminate Option C if Hydro's evidence is that its characteristics (slow response time) are not of value.

In the future, consideration should be given to the CRP being expanded from its current form after a more thorough review, with proper statement of the long-term benefits. However, any such expansion must be guided by ensuring that adding more CRP load than the 100 MW Option R and 230 MW Option A did not serve to undermine the value of the program (and the dollar value of the credit) to existing participants.

As reviewed in Mr. Bowman's Pre-Filed Testimony, Hydro's short-term view on the economics of the program (i.e., only considers value on a one-year basis) is not consistent with its assessment of any other DSM or investments, and greatly understates the potential role that the CRP plays from a system operating perspective and the long-term benefits that can be reasonably relied upon from this program. The CRP has been successfully in operation with significant load (and growth in participating load) for over 20 years and there is no reasonable basis to conclude that all participating customers may drop off within one year, as is the basis for Hydro's limited benefit assessment at the present time.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION: