Manitoba Hydro

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August 12, 2016

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO'S 2015 COST OF SERVICE METHODOLOGY REVIEW – WRITTEN SUBMISSION ON ISSUES NOT SUBJECT TO ORAL HEARING

Please find attached Manitoba Hydro's Written Submission on Issues Not Subject to Oral Hearing as per the Revised Hearing Timetable issued by the Public Utilities Board ("PUB") in Order 84/16.

Should you have any questions with respect to the enclosed, please contact the writer at 204-360-3633 or Janelle Hammond at 204-360-4161.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

ODETTE FERNANDES
Legal Counsel

Att.

MANITOBA HYDRO'S WRITTEN SUBMISSION
WITH RESPECT TO ISSUES NOT SUBJECT TO ORAL EVIDENCE
2015 COST OF SERVICE METHODOLOGY REVIEW

INDEX

1.0 INTRODUCTION

On December 4, 2015, Manitoba Hydro filed its Cost of Service Methodology Review submission with the Public Utilities Board (PUB). The first Pre-Hearing Conference related to the Review was held on February 12, 2016 and led to Procedural Order 26/16, which established as part of the review process one round of written Information Requests to Manitoba Hydro followed by two facilitated workshops. The first workshop from May 11-13, 2016, consisted of Intervener consultants, PUB advisors and the PUB Board Members posing questions to Manitoba Hydro. The Manitoba Hydro workshop was followed by Intervener Evidence on June 10, 2016 and the second facilitated Intervener Workshop from June 21-23, 2016.

During a second Pre-Hearing Conference on June 24, 2016, parties made submissions to the Board regarding which key issues should be subject to oral evidence and which issues could be appropriately addressed through written submissions. The PUB issued Order 84/16 which directed Manitoba Hydro to file Rebuttal Evidence on July 29, 2016 followed by Intervener Rebuttal Evidence on August 5, 2016. In accordance with the timeline established in Order 84/16, all parties are to file written submissions on issues not subject to the oral hearing on August 12, 2016.

Manitoba Hydro is therefore providing its written submissions on COS methodology issues not subject to the oral hearing and identified as “in-scope” by the PUB in Order 26/16.

2.0 A SIMPLIFIED POOLED APPROACH TO GENERATION IS REASONABLE FOR MANITOBA HYDRO’S SYSTEM INCLUDING COAL AND WIND

Since the conclusion of the Stakeholder Session held by Manitoba Hydro in late 2014, Manitoba Hydro has given considerable thought and assessed the perspectives shared by Stakeholders, as well as the advice it received from its consultant Christensen Associates Energy Consulting LLC (CA), regarding past treatments of its generation resources including natural gas, coal and wind for purposes of Export cost responsibility. This resulted in

PCOSS14-Amended which reflects a pooled approach for the purposes of classifying and allocating these costs. Past extensive reviews of each of these resources led to complex treatments that Manitoba Hydro viewed as not necessarily reflective of either cost causation or the use of these assets in drought or high water conditions. Manitoba Hydro believes that while it is possible to approximate the cost of exports, it is simply not possible to precisely ascertain them, and this is evident by the extensive past review and record regarding export treatment in Cost of Service. However, the real issue for Cost of Service is not how much do exports cost, but rather what is the fair and reasonable cost to serve Manitoba customers by class. Given this, Manitoba Hydro has elected a simplified approach to avoid further complex and detailed, yet rather imprecise, examination of individual generation resources, in view of uncertainty about use during any one period.

A case can be made that the most cost causal treatment of Coal Generation is direct assignment to Domestic customers, given that current legislation allows Manitoba Hydro to draw upon these resources for Domestic customers in emergency circumstances only (Manitoba Hydro Submission dated December 4, 2015, Appendix 1, page 4). However, Manitoba Hydro views that the improved precision arguably gained by the exclusion of coal from the allocation to Dependable Exports is not worth the increased complexity associated with the creation of an additional generation pool. In PCOSS14-Amended, the allocation of Coal Generation costs to dependable exports is approximately $4.5 million. With the exception of Mr. Bowman, all other interveners to this proceeding agree with this treatment and in particular this matter is discussed insightfully by Mr. Harper in his evidence at pages 18 and 57. In particular at page 57 of Mr. Harper's evidence, he states:

> *"It is noted that the added complexity of assigning thermal generation to just domestic load extends well beyond the need for a third pool for Generation costs. If thermal generation is to be assigned solely to the domestic classes then the allocators for domestic classes used to assign the balance of the generation costs between domestic classes and dependable exports would need to be adjusted in some manner to account for the fact that a portion of their service requirement are being met by thermal generation."*

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

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

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

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

3.0 SUBTRANSMISSION

3.1 Subtransmission Is Appropriately Functionalized

Manitoba Hydro's subtransmission function includes lower voltage (66 kV and 33 kV) subtransmission lines, as well as the low voltage portion of the substations. These facilities are required to bring the power from the common bus network to specific load centers. In his Evidence Mr. Chernick takes issues with Manitoba Hydro's functionalization of these facilities on the basis that they should be viewed as complementary to the transmission system as opposed to incremental. This complementary view being proposed by Mr. Chernick, takes the cost allocation process down the path of allocating the costs of subtransmission to all rate classes regardless of whether or not these classes make use of the assets. Allocating transmission cost to the GSL>100 kV class for assets they do not use has a material adverse impact on their RCC of 4.3% (Manitoba Hydro Rebuttal Evidence, page 29) while conversely, the increase in RCC of every other class is less than one percentage.

Manitoba Hydro agrees with the perspectives provided by Mr. Bowman (Rebuttal Evidence of Patrick Bowman, page 16) that it is widely accepted in cost allocation practice "that customers served off of the bulk transmission at high voltages should not be allocated the costs of lower voltage systems (such as sub transmission and distribution)". Manitoba Hydro does not agree with Mr. Chernick's characterization of these assets and believes that the current functionalization, which is consistent with the Electric Utility Cost Allocation Manual prepared by the National Associate of Regulatory Utility Commissioners (NARUC), is more appropriate for its system (page 73) also cited by Mr. Bowman (Rebuttal Evidence of Patrick Bowman, pages 16-17).

Manitoba Hydro understands Mr. Chernick's position to be that because Subtransmission and Transmission may, in some cases be substitutable, that they are fully substitutable. This is not the case. For some larger loads or distribution substations, the decision to serve from Transmission or Subtransmission may be tied to proximity or to relative economics. However, this does not make Subtransmission capable of fulfilling the overall role of

Transmission, which is strongly geared to provide across-the-system reliability, made possible by meshed high voltage AC networks to provide multiple paths for power flows under various contingency events. Some of the very large loads served in the GSL>100 kV class can only be served at Transmission voltage. Subtransmission on the other hand is a matter of local and non-meshed transportation. There is no "across the system" network of subtransmission. Downtown Winnipeg for example, is networked, but it is only locally networked.

If Mr. Chernick were correct about the substitutability of one for the other, it would be just as correct (or rather, just as incorrect) to say that Subtransmission and Distribution should also be combined because the one may substitute for the other in some circumstances.

Mr. Chernick alternatively offers excusing 35% of Distribution classes' load from Subtransmission costs on the grounds that this is the proportion of Distribution load that is served directly from substations with Transmission voltage at the high side as an alternative (Rebuttal Evidence of Paul Chernick, page 30). However, this simply forces the adverse effect from the GSL>100 kV class to the GSL 30-100 kV class. The impact of Mr. Chernick's proposal would decrease the RCC for the GSL 30-100 kV class by about 3% while all other class' impacts would be negligible.

Two thirds of Distribution loads require both Transmission and Subtransmission. For the other third, installed voltage transformation facilities must be capable of accepting power at a higher voltage in lieu of subtransmission. It is therefore appropriate to fully allocate these costs to the customer classes served by these facilities or the distribution facilities that substitute for them. Manitoba Hydro cannot rationalize a cost allocation result which would have the GSL>100 kV customers who directly pay for and own this type of transformation equipment, also contributing through rates towards costs for similar type facilities used to serve distribution-level customers.

3.2 Manitoba Hydro's Allocation of Subtransmission Costs based on NCP is Reasonable

There are many acceptable methods for allocating subtransmission costs including variations of non-coincident and coincident peak. Manitoba Hydro's current approach is to allocate these costs on the basis of a single non-coincident peak. CA provided advice on Manitoba Hydro's use of a non-coincident peak allocator in their 2012 report stating this "approach is very common throughout the industry and certainly reasonable for MH" (CA Report dated June 8, 2012, page 16, filed as Appendix 5 of Manitoba Hydro's Submission dated December 4, 2016). CA did however suggest that Manitoba Hydro consider investigating the influence of system peak to assess its NCP allocator. As part of Manitoba Hydro's response to that Report (Appendix 4 of Manitoba Hydro's Submission dated December 4, 2016), Manitoba Hydro agreed that the current approach is reasonable and consistent with industry practice but intended to explore the recommendation by CA[1].

Mr. Chernick takes exception with Manitoba Hydro's use of NCP and states in his evidence that "*subtransmission should be allocated on the same broad summer and winter peak-loads allocator used for transmission*" (Evidence of Paul Chernick, page 42). Mr. Chernick is also recommending that CP should be preferred for allocating all Distribution demand-related cost. In his Rebuttal Evidence (pages 27 through 29), Mr. Chernick offers up an alternative to his previous suggestion of using a 2CP allocator and has provided a table with the "Monthly CP Weighted by Substation Peaks" allocator. Manitoba Hydro is unable to duplicate the calculations supporting this table and has found a number of errors. Manitoba Hydro also notes that the analysis is mixing 2011/12 Load Research results with 2014/15 substation peak data. Since neither data set reflects weather normalization that occurs from averaging eight years of annual load data, as Manitoba Hydro does in the calculation of NCP and CP allocators, using two different years as a basis for the allocator could lead to skewed seasonal results, making Mr. Chernick's analysis unreliable, and providing no value to the proceeding.

[1] Manitoba Hydro's Response to the Cost of Service Recommendations of Christensen Associates Energy Consulting, dated July 19, 2012, pg. 10

Furthermore, the three conclusions drawn by Mr. Chernick on page 29 of his rebuttal evidence in no way lead to the overall indication that NCP greatly overstates the responsibility of the residential class for substations, subtransmission and feeders as he claims. One could just as easily conclude that an allocator based on CP under-allocates costs to the residential customers. The only thing Mr. Chernick's analysis shows for certain is that he has a predisposition to favoring a CP allocator for subtransmission and distribution demand-related cost. His proposed allocator is simply a 12 CP allocator weighted by number of substations peaking in each month. Mr. Chernick's proposed analysis assumes his conclusion; in other words, by using class monthly coincident peaks he is assuming, not demonstrating, that 12 CP is a superior allocator.

In his Evidence at page 57:7-11, Mr. Chernick states: "*Hydro should estimate the contribution of each class to the most constrained loading (i.e. the hours when load on the substation is the highest percentage of its seasonal rating) on each substation, or a representative sample of substations.*" Although the type of analysis suggested by Mr. Chernick in his Rebuttal Evidence at page 26 could be performed by having an "*analyst spend a few hours manipulating the best available data in a spreadsheet*" this is not the same type of detailed analysis that he recommended earlier in his Evidence. Properly conducted, the analysis being requested would in fact require extensive additional load research metering investment to provide statistically valid sampling of class loads at the substation level to determine class contribution to the hours in which the substation is most constrained. To do this for a reasonably representative sample of substations would entail the installation of hundreds of additional load research meters.

Other alternatives, including a determination of a reasonable sample of the high load hours of the substations collectively or employing data from the few substations from which accurate data is available, while not necessarily a representative sample, would both still be costly by requiring the installation of metering or time consuming by requiring the mapping of customer numbers and energy use by substation to estimate the relevant class loads using load research data from the province-wide samples.

Mr. Chernick's approach in his Rebuttal Evidence (page 28), using class monthly system coincident peak loads, does not measure peaks at the substation level but only at the overall system level. The approach proves nothing about the actual class loads at the time of station peak, which is what he was suggesting in his Evidence that Manitoba Hydro measure. There is no more basis for using system monthly weighted 12CP to measure class contribution to substation peaks than there is for using system monthly weighted 12 NCP, which approach is used by Puget Sound Energy (Rebuttal Evidence of Mr. Harper, Attachment A, Leidos jurisdictional review of cost of service, page C-13).

In summary, the material provided by Mr. Chernick provides no evidence that CP is superior to NCP. Manitoba Hydro notes that no other intervener has taken an issue with Manitoba Hydro's industry accepted practice of using NCP, and maintains that the current method remains reasonable. Manitoba Hydro submits therefore that it is reasonable to continue using NCP as an allocator for demand-related cost of subtransmission and distribution.

4.0 DISTRIBUTION

4.1 Manitoba Hydro's Classification of Distribution Costs is Well Accepted Industry Practice

Manitoba Hydro's proposed classification for most categories of Distribution plant and associated costs are not contested. The exception is the Poles and Wires category which makes up approximately half the total cost in the Distribution function.

Manitoba Hydro classifies Poles and Wires cost as 60% related to class demands and 40% related to class customer numbers. This longstanding practice recognizes that the design for poles and wires considers line length and customer density which are, in turn, driven by where customers choose to locate in addition to load requirements of the customers (PUB/MH I-48).

CA recommends that Manitoba Hydro retain its current method of allocating distribution plant costs "as it is in line with industry practice" (CA Report dated June 8, 2012, page 19, filed as Appendix 5 of Manitoba Hydro's Submission dated December 4, 2016). To support this recommendation, CA states (pages 17-18):

> *For distribution, the NARUC cost allocation manual recognizes demand- and customer-related allocation vectors. Dual cost attribution – i.e. demand- and customer-related- for electric distribution is based on the notion that interconnection of loads to the distribution system induces the service provider to incur some level of costs without regard to load size…"*

Mr. Chernick disputes that there is a customer related component in Poles and Wires and recommends in his Evidence (pages 47-48) that Manitoba Hydro classify all Distribution other than service drops and meters as demand-related and lists a number of utilities that follow that practice. Mr. Chernick does not believe that the Minimum System or the Zero Intercept method (two approaches used by utilities to calculate classification ratios for distribution facilities) are a reliable basis for classification (page 48). However, Mr. Chernick does acknowledge that many utilities continue to identify a minimum distribution system (Intervener Workshop, Transcript page 674). He also acknowledges that a majority of utilities include some customer related portion in their allocation (Transcript page 675) although he continues to assert that it is not the right way to do it.

Mr. Chernick also cites utility economist James Bonbright's observations as an authority on whether or not to attribute a minimum-system requirement as a customer-related cost (Mr. Chernick Evidence, page 49). Under questioning by Mr. Harper and, subsequently by Mr. O'Sheasy, Mr. Chernick agreed that Bonbright had also concluded that there was an even weaker case for attributing such cost as demand-related (Intervener Workshop, pages 636-638 and 675-677).

Manitoba Hydro is also of the view that intuitively, it would seem that there is a component which, in the very least, is not load-related. It would not be difficult to find situations, within

Manitoba or elsewhere, where two separate distribution feeders serving a similar aggregate load have substantially different cost due to one serving a more widely dispersed customer base, or a greater number of customers with smaller average loads. Distribution is about power delivery and largely a matter of distance. Poles and Wire costs will increase largely in proportion with the change in distance to connect the customer. Conversely, an increase in demand will cause only a modest increase in the cost of the conductor. This is because of economies of scale and because higher voltages driven by increased peak loads can provide increased carrying capability. That is, a doubling in voltage can generate a carrying capability that increases four times. On this basis, Manitoba Hydro views it reasonable to incorporate at least some customer component in the classification of Poles and Wires and certainly not zero as Mr. Chernick believes.

No intervener at the current proceeding has proposed an alternative to Manitoba Hydro's use of a 100% Demand allocator for distribution transformers. Mr. Harper's Evidence (page 78) noted that recent surveys show a wide range of Demand / Customer splits among utilities for both Poles and Wires and Distribution transformers, and Mr. Harper recommended updating the split but did not make a particular recommendation as to what that split should be.

Manitoba Hydro's classification of Distribution facilities is in line with industry practice. On balance, considering the 60/40 split used by Manitoba Hydro for Poles and Wires and the 100% Demand allocation for Distribution transformers, there is a reasonable share of Distribution costs allocated on a Demand basis.

Manitoba Hydro's workshop presentation on this matter identified the impact of varying the Demand/Customer split for Poles and Wires (Exhibit MH-20, page 65). To generalize, each increase of 10 percentage points in the share allocated on a Demand basis reduces the cost responsibility of the Residential class by 0.6% and increases the cost responsibility of some General Service classes, notably GS Small Demand and GS Medium, by up to 1.0%.

Customer Class	60% Customer 40% Demand RCC Change	50% Customer 50% Demand RCC Change	30% Customer 70% Demand RCC Change
Residential	-1.30%	-0.70%	0.60%
General Service - Small Non Demand	0.10%	0.00%	-0.10%
General Service - Small Demand	1.90%	1.00%	-0.90%
General Service - Medium	2.10%	1.10%	-1.00%
General Service - Large 0 – 30 kV	1.30%	0.70%	-0.70%
General Service - Large 30-100 kV	0.00%	0.00%	0.00%
General Service - Large >100 kV	0.00%	0.00%	0.00%
Area & Roadway Lighting	-0.70%	-0.30%	0.40%

Adoption of Mr. Chernick's recommendation to allocate all Pole and Wire cost on a demand basis would likely have a material RCC impact on all these classes. However, such an extreme change to the classification ratio does not appear to be warranted on the basis of the evidence reviewed during this proceeding, including NARUC's recommendations, Canadian utility practice and a commonsense perspective on the potential for Pole and Wire cost to vary on the basis of factors other than load.

4.2 Manitoba Hydro's Allocation of Demand-related Distribution Costs on NCP is consistent with Industry Practice

Manitoba Hydro allocates the demand portion of its distribution system using NCP based on data gathered through its Load Research Program. This method is recognized as an appropriate allocation method throughout the industry and was endorsed by CA (CA Report dated June 8, 2012, page 19, filed as Appendix 5 of Manitoba Hydro's Submission dated December 4, 2016).

Conversely, Mr. Chernick's Evidence (pages 57-58) suggests that a 2CP allocation method would be preferable in the short term, while an allocation method that considers the class contribution to the most constrained loading on each substation and feeder should be the long term goal. The latter approach suggested by Mr. Chernick involves data sets and inputs that Manitoba Hydro does not have or maintain or would have to acquire at significant cost.

In his Rebuttal Evidence, Mr. Chernick updates his 2CP recommendation and offers his "Monthly CP Weighted by Substation Peaks" as the preferred alternative in the interim. As discussed in Section 3.2, Manitoba Hydro does not believe this analysis to be relevant to the choice between CP and NCP as an appropriate allocator for demand-related Distribution cost.

No interveners with the exception of Mr. Chernick oppose Manitoba Hydro's use of an NCP allocator for the demand portion of Distribution. Manitoba Hydro submits that it is reasonable to continue to use the NCP allocator.

4.3 Secondary Shares

The customer and demand factors used to allocate Distribution Poles and Wires costs were reduced by 30% for the GSL 0-30kV class to recognize that these customers do not utilize Manitoba Hydro's secondary voltage Distribution facilities. Since Manitoba Hydro does not distinguish between primary and secondary plant in its accounting records, other than for underground cable, the estimated secondary share of costs was based on prior advice received from an external expert consultant.

In his Evidence Mr. Harper notes that due to age of the estimate, and changes to the distribution system since that time, "*It would be prudent for Manitoba Hydro to investigate ways of updating this percentage split used for primary/secondary costs*". (Evidence of Mr. Harper, page 77)

Mr. Chernick has undertaken to provide this updated estimate of the split in his Evidence (page 60). The calculation uses a further breakdown of Distribution Pole and Wire costs into four subcategories as provided by Manitoba Hydro, as well as his professional judgment on the secondary component residing within each subcategory.

His assumptions result in an estimated secondary share of Distribution Poles and Wires of 20%, and he goes on to conclude that the 30% used by Manitoba Hydro "*probably overstates* *that portion of costs, and hence the discount for the GSL<30kV class*" (Evidence of Paul Chernick, page 59). Eliminating the allocation of secondary Distribution costs to the GSL 0-30 kV class resulted in a 1.8% increase in the class RCC when a 30% estimate was used (PUB/MH I-72b). It would appear reasonable to assume that changing to a 20% estimate would claw-back 0.6% of this RCC increase.

Manitoba Hydro has no reason to believe that the current 30% secondary share is no longer appropriate, but also notes that the calculation provided by Mr. Chernick is a reasonable approach given the data availability. Manitoba Hydro is prepared to accept Mr. Chernick's determination for use in future Cost of Service Studies.

5.0 POLICY-RELATED ADJUSTMENTS IN COST OF SERVICE

5.1 Uniform Rate Adjustment (URA)

Prior to 2001, Manitoba Hydro rates differentiated among customers served in Winnipeg, (Zone 1); other cities, towns and villages (Zone 2) and rural (Zone 3). The different rates for the Basic Monthly Charges and first block energy charges applied to customer classes served from the Distribution system: Residential; General Service Small; General Service Medium and Area and Roadway Lighting.

In 2001, Bill 27 amended *The Manitoba Hydro Act*, C.C.S.M cH190 to enforce equalization of rates for power within customer classes across the province. Rates were directed to be equalized to the lowest rate in effect, i.e. the Zone 1 rate. As a consequence of implementing uniform rates Manitoba Hydro incurred a loss of revenue estimated at the time to be $14 million, which was mostly from the Residential class. In the first cost of service studies filed after implementation of uniform rates, the revenue reduction was reflected in the forecast revenue attributable to the affected classes, with the result that the class Revenue to Cost ratios fell from what they would have been prior to the implementation of the uniform rates. The long term implication was that future rate increases to this class would be higher than they would have been absent the uniform rate legislation.

The Consumers Association of Canada/ Manitoba Society of Seniors (CAC/MSOS) argued, during the review of Manitoba Hydro's 2004 rate application, that incorporating the revenue impacts of the uniform rates legislation into the Cost of Service Study was inappropriate and that it was not the intent of legislature or the government that Winnipeg customers in the affected classes, most notably Residential, should alone bear the burden of subsidizing customers in the rest of the province. In Order 101/04, the PUB directed Manitoba Hydro to assign the cost of the uniform rates against net export revenue (Order 101/04 pages 19, 26 and 36.) This is the procedure that Manitoba Hydro has incorporated in all Cost of Service studies filed since that Order. In PCOSS14, the amount of revenue affected by the URA has increased to $23.5 million.

Other than Mr. Bowman, no intervener has taken issue with Manitoba Hydro's practice to treat the URA as a charge against Net Export Revenue. Mr. Bowman's recommendation in his Evidence, page 46, is that URA be excluded from COS which, if implemented would leave an amount of cost equal to the URA to be reflected in the RCC of classes to whom the offset applies. In the framework of PCOSS14, the exclusion of URA would result in the RCC for the Residential class declining by 1.8 percentage points (MIPUG/MH I-11a) and the burden of adopting Mr. Bowman's recommendation falls almost entirely on the Residential class.

The reasoning behind Mr. Bowman's recommendation appears on page 45 of his evidence:

> *It has now been 15 years since the one-time rate adjustment occurred to distribution customers. Rates today are not burdened by revenue shortfalls arising directly from this 2001 directive.* (lines 18-19)

And, further:

> *"The difficulty also arises that the adjustment distorts the cost measurements for the affected classes.* (line 23)

Manitoba Hydro acknowledges that postage stamp rates in numerous jurisdictions do not incorporate ongoing explicit subsidies and that generally, implicit subsidies to certain consumers within a class (e.g. Rural) are typically funded within the class Manitoba Hydro also recognizes, along with its Consultant CA (CA Report dated June 8, 2012, page 10, filed as Appendix 5 of Manitoba Hydro's Submission dated December 4, 2016), that the costs offset by the URA are in fact a cost to serve the associated classes and that assigning NER to cover these costs distorts the true margin from energy sales.

Manitoba Hydro submits that the Board has previously ruled on this matter in Order 101/04 (page 26). In that Order the PUB stated *"the current methodology does not meet the Board's interpretation of the intent of the uniform residential rate legislation"*. The COS methodology referred to reflected the reduced revenue of the classes impacted by Uniform Rates which was primarily the Residential Class. Manitoba Hydro was directed to "*allocate the cost of uniform residential rate as a first charge on net export revenue*" (page 36). Unless the current Board is convinced that conditions regarding the ability of the affected classes, particularly the Residential class, to fund the subsidy or other relevant conditions have since changed, it would be appropriate to continue with the current treatment.

5.2 Affordable Energy Fund

Manitoba Hydro established an Affordable Energy Fund (AEF) in accordance with the provisions of *The Winter Heating Cost Control Act* SM 2006, c.5 (assented January 1, 2006) in the initial amount of $35 Million for the purpose of providing support for programs and services that encourage energy efficiency and conservation; encourage the use of alternative energy sources; and facilitate research and development of alternative energy services and innovative technologies. On June 14, 2012, *The Energy Savings Act, SM 2012, c.26* was assented repealing *The Winter Heating Cost Control Act* and continued the AEF.

Section 4(3) of *The Energy Savings Act*, clearly states that any contribution to the fund is to come from export revenues:

> **Manitoba Hydro to contribute to fund**
>
> 4(3) The corporation is to contribute to the fund from time to time the proportion of its gross revenue ***from the sale of power to customers outside Manitoba*** that the corporation, in consultation with the minister, considers necessary to carry out the purposes of the fund. (Emphasis added)

Mr. Bowman's Evidence appears to take issue with Manitoba Hydro's accounting approach and states (page 47):

> *"While the Cost of Service review is not the appropriate time to deal with Hydro's accounting approach, it is appropriate to consider whether there is in fact a cost that should be included in PCOSS14-Amended related to the AEF. Based on the fact that this was to be a program that was fully funded from a portion of Hydro's 2006/07 earnings, there does not appear to be any reason to include the AEF as a cost in any PCOSS for years after 2006/07. "*

and

> *"The only issue with this approach appears to be Hydro's practice which seeks to balance each PCOSS to 100.00% Revenue Cost Comparison (RCC) for the system as a whole."*

Mr. Bowman goes on to say that the recommendation to exclude AEF from the COS is consistent with the recommendation provided by CA. Despite the fact that the recommendation from both parties is the same, the reasoning behind the recommendation appears to be completely different. Drawing any comparisons then between the two is misleading.

Manitoba Hydro does not agree with Mr. Bowman that there has been no cost related to the AEF since 2006/07. The fund has been set up as a regulatory deferral and is amortized and charged to net income based on the spending that occurs each year. To simply ignore a regulatory deferral account in COS and report a quantum of costs different than the approved IFF with no corresponding adjustment to net income or revenue is not logical. It in fact offends a primary COS goal, that Cost of Service must recover the approved revenue requirement of the utility, a goal acknowledged appropriately by Mr. Bowman as a "standard" measure for Cost of Service (Bowman Evidence, page 17).

As of March 31st, 2015, the original fund was largely spent with $6.1 million remaining. In conclusion, it is Manitoba Hydro's view that the current treatment of allocating AEF a policy charge against Net Export Revenue be maintained given that it is simply inappropriate to ignore costs in Revenue Requirement for COS and is in accordance with the intent under *The Energy Savings Act*.

6.0 OTHER MATTERS

There are numerous other modifications or further study required that were identified by Interveners as discussed in the following sections.

6.1 Manitoba Hydro Accepts MIPUG's Recommendation to Modify its Curtailable Rate Program COS Treatment

Mr. Bowman's Evidence (pages 42-43) notes that, unlike other DSM programs, the Curtailable Rate Program (CRP) does not result in energy benefits for participants, rather there is a cost of service credit applied against the Generation function equivalent to the forecast annual credits provided to the participating customer. He also notes the discrepancy between the value of this credit in PCOSS14 ($5.8 million) and the CRP-related DSM cost assigned directly to the class ($8.5 million), which is based on the ten year amortization of the accumulated benefits.

In its response to MIPUG/MH I-16(e), Manitoba Hydro explains the discrepancy as related to the timing differences between the cost of capitalized program expenditures and the annual credits paid. In the early years of the program the benefit exceeded the cost (by as much as $3.8 million in PCOSS06) but with accumulation of the capitalized cost, and amortization over 10 years, the amortized cost now exceeds the credit applied in the Cost of Service study.

Manitoba Hydro also notes in the response to MIPUG/MH I-16(f) that the timing differences related to the treatment in the COS would have increased the Curtailable customer RCC's in the early 2000s, and decreased them in more recent studies, but have had no direct impact on rates.

Mr. Bowman notes that Manitoba Hydro's overall approach is appropriate (page 42) and recommends a simple adjustment to ensure the credit in the PCOSS matches the full revenue requirement associated with the program (page 43). The adjustment will increase the RCC of GSL 30-100 kV by 0.2% and the GSL >100 kV by 1.0%, while other classes would experience a minor RCC decrease of 0.2% or less. It appears that Mr. Harper (Intervenor Workshop Transcript pages 349, 393) would not oppose such an adjustment.

Manitoba Hydro accepts MIPUG's recommendation and intends to make this adjustment in the next PCOSS.

6.2 Manitoba Hydro Accepts Coalition's Recommendation to Modify its Allocation of Late Payment Revenue

In its Evidence (page 37), Mr. Harper recommends that Late Payment Revenue be allocated to customer classes (excluding Street Lights, GSL>30 kV and SEP>30 kV) based on their pro-rata share of historical Late Payment Charges. While the impact, as identified in the table below, under either method is minor given that late payment revenue is less than one percent of total domestic revenue, Manitoba Hydro accepts that this is a reasonable approach and likely more cost-causative than its current allocation based on class revenue. Manitoba Hydro intends to make this modification as part of its next PCOSS.

Customer Class	RCC* Change
Residential	0.3%
General Service - Small Non Demand	-0.4%
General Service - Small Demand	-0.3%
General Service - Medium	-0.3%
General Service - Large 0 – 30 kV	-0.2%
General Service - Large 30-100 kV	0.0%
General Service - Large >100 kV	0.0%
Area & Roadway Lighting	0.0%

*Mr. Harper evidence, page 39

6.3 Customer Service – General Costs Allocator

Manitoba Hydro uses a weighted allocator for "C10 Customer Service – General" costs that is based on estimates of the efforts various departments devote to each customer class, which are then weighted by the budget for each area. Both Mr. Bowman (Evidence of Mr. Bowman pages 37-39) and Mr. Chernick (Rebuttal Evidence of Mr. Chernick pages 34-35) raise concerns about the level of detail to support the class responsibility estimates for the costs identified as "Customer Service – Other". Manitoba Hydro expects to undertake to review and update as necessary these allocators in conjunction with the preparation of the next PCOSS.

6.4 The Allocation of Service Drop Costs for Shared Services

Messrs Chernick and Harper both state that Manitoba Hydro should amend its allocator for service drops to account for shared services. Manitoba hydro acknowledges the weights used to allocate service drops were developed many years ago and may or may not already reflect shared services. However, as the recommended improvements were shown to have virtually no impact (Evidence of Mr. Harper, page 80), Manitoba Hydro does not consider additional review to be a priority at this time.

6.5 Corrections to Inputs

During the course of this process, a number of required corrections to the data inputs related to customer counts, functionalization of common costs, and SEP weightings were identified. The specific items are discussed in detail in the Evidence of Mr. Harper (pages 39-40, 90). The cumulative impacts of the corrections have been provided on page 40 of Mr. Harper's evidence and are presented below.

Customer Class	RCC Change
Residential	0.2%
General Service - Small Non Demand	-0.1%
General Service - Small Demand	-0.2%
General Service - Medium	-0.1%
General Service - Large 0 – 30 kV	-0.2%
General Service - Large 30-100 kV	0.0%
General Service - Large >100 kV	-0.3%
Area & Roadway Lighting	0.1%

Manitoba Hydro proposes to make the recommended corrections in future studies.

Additionally, Mr. Harper suggests (Evidence of Mr. Harper, page 37) improvement be made to the process used to functionalize Other Revenues in the COS model. Manitoba Hydro provided its position in response to COALITION/MH I-2b-e but clarifies that these revenues are actually assigned to individual Cost Centres within the functions, and not merely broken down between the five functions and the improvements recommended by Mr. Harper are therefore already reflected in the COS study.

6.6 Treating Street and Sentinel Lighting as Separate Subclasses is Not Feasible

Manitoba Hydro's Cost of Service study includes Street and Sentinel Lighting combined into a single Area and Roadway Lighting (A&RL) class. Mr. Todd recommends in his Evidence at page 6 that separate Street and Sentinel Lighting subclasses be created in order to allocate Billing costs:

> *"It would be feasible to treat street and sentinel lighting as separate sub-classes in the PCOSS with the full amount of billing costs currently being allocated to the A&RL class being divided between the Street and Sentinel sub-classes in proportion to the number of separate bills (or services) in each class." (Mr. Todd Evidence page 6)*

While Manitoba Hydro is able to identify revenue and forecast energy and demand separately for Street and Sentinel Lighting, its accounting records do not support the separation of the dedicated lighting costs. These costs represent the vast majority, or 70%, of the costs of serving the A&RL class. Without such data, estimating the cost shares by subclass would need to rely on a simple proportional method proposed in Mr. Todd's evidence or some other analysis to prorate these cost shares. It would appear inappropriate to segregate the subclasses in the PCOSS solely to allocate $263,000 of A&RL Billing costs, while not being able to meaningfully segregate 70% (or $15 million) of the class' costs. Manitoba Hydro's current approach of treating all lighting as a single class in the Cost of Service Study is also common in the industry (Evidence of John Todd, page 5). Manitoba Hydro intends to continue with the current approach that it views to be reasonable.

7.0 ORDER 26/16 ISSUES AND OUT OF SCOPE ITEMS

7.1 Rate Design and Rate Rebalancing Matters

In Order 26/16, the PUB accepted that rate-related matters, including rate rebalancing, time of use rates and conservation rates should be excluded from the scope of the hearing. The PUB further indicated that the existing proposal for industrial Time of Use Rates was best addressed at the same time as any proposal for conservation rates that Manitoba Hydro is required to advance pursuant to Provincial policy.[2]

[2] PUB Order 26/16, pg. 16

The Board advised that it intended to examine the components of the basic monthly charge, and the split between energy charges and demand charges as part of the review as they relate directly to cost of service study issues. In response to PUB/MH I-35a-d, Manitoba Hydro provided information and advice on these issues. As discussed in Manitoba Hydro's letter of February 5, 2016 (page 5), Manitoba Hydro was retaining an expert to prepare analysis and alternative rate options for consideration with respect to conservation rates. The alternative rate option scenarios are to consider the appropriate levels for the Basic Monthly Charge, the pricing and size of the first energy block and the pricing and degree of inversion for the run-off block. Manitoba Hydro noted in its correspondence that it expects to engage stakeholders in the discussion of these alternative rate options later in 2016.

Although the PUB asked a few questions of Manitoba Hydro, Interveners did not ask any IRs on the issue of basic monthly charges and the split between energy charges and demand charges. Manitoba Hydro notes that during the Intervener Workshop session PUB advisor, Mr. Brady Ryall, asked Intervener consultants Mr. Harper, Mr. Bowman, and Mr. Chernick whether they had observations or comments for the PUB with respect to these charges.[3] Mr. Bowman indicated that MIPUG was satisfied to wait on discussing these issues until time of use rates were considered.[4] Mr. Chernick commented on why the cost of service study should generally not drive rate design.[5] Mr. Harper indicated that the issue was not part of his overall mandate but offered a high level view and properly noted:

> "*-- I think -- think the issue is that when it comes to rate design there is more than one (1) consi -- one (1) consideration that -- that goes into it.*" and "*…you have tradeoffs to make bet -- between those two (2). And unless you can -- and until you look at the results of both and try and make -- make -- and sort of decide to what extent you want to make those tradeoffs …*" [6]

[3] Intervener Workshops - Mr. Patrick Bowman, June 21, 2016, Transcript pgs. 326-328; Mr. William Harper, June 22, 2016, Transcript pgs. 582-583; Mr. Paul Chernick, June 22, 2016, Transcript pgs. 704-706.
[4] Intervener Workshops, June 21, 2016, Transcript pg. 328.
[5] Intervener Workshops, June 22, 2016, Transcript pgs. 704-706.
[6] Intervener Workshops, June 22, 2016, Transcript pgs. 583-584.

Manitoba Hydro submits that these issues have not been properly canvassed or reviewed in this cost of service review and it is premature for the PUB to make any determination with respect to these rate design issues.

7.2 Terms and Conditions of Service and Service Extension Policy

In Order 26/16, the PUB advised that it intended to review Manitoba Hydro's Terms and Conditions of Service and Service Extension Policy.[7]

Manitoba Hydro included the Standard Terms and Conditions for Electric Service Agreement as an attachment to PUB MFR 18. The terms and conditions contained in the attachment to PUB MFR 18 are established under *The Manitoba Hydro Act*, C.C.S.M. c. H190, Electric Power Terms and Conditions of Supply Regulation 186/90). Manitoba Hydro also included as an attachment to PUB MFR 16, a copy of the Power Supply Agreement provided to General Service Large customers

Manitoba Hydro responded to IRs from the Coalition regarding its terms and conditions of service in order to assist the PUB in understanding its terms and conditions. As noted previously on a number of occasions, *The Manitoba Hydro Act* clearly places jurisdiction over the terms and conditions with the Manitoba Hydro-Electric Board. Certain aspects of the terms and conditions are subject to Lieutenant Governor in Council approval as noted in section 28(1) and section 52 of *The Manitoba Hydro Act*:

> **Regulations as to supply of power**
> 28(1) The board may, by regulation, prescribe
>
> (a) the terms, and conditions upon and subject to which the corporation will supply power to the users of the power supplied by it;

[7] PUB Order 26/16, pg. 16.

(b) the standards governing the construction, installation, maintenance, repair, extension, alteration, and use of electric wiring and related facilities using or intended to use power supplied by the corporation;

(c) such other conditions relating to the supply of power to users of that power, not inconsistent with this Act, as the corporation deems necessary for the proper carrying out of this Act and for the efficient administration thereof.

Regulations

52 For the purpose of carrying out the provisions of this Act according to their intent, the board, with the approval of the Lieutenant Governor in Council, may make such regulations and orders as are ancillary thereto and are not inconsistent therewith; and every regulation or order made under, and in accordance with the authority granted by, this section has the force of law; and, without restricting the generality of the foregoing, the board, with the approval of the Lieutenant Governor in Council, may make regulations and orders:

(a) requiring the owner of any power plant or works to furnish to the board any information required by the board regarding

(i) his plant and works including the capacity, output, cost, and use thereof;

(ii) his assets, liabilities, revenues, expenses, and operations;

(iii) the supply of power by him to other persons including particulars of quantities, prices, terms, conditions, points of delivery and use;

> (b) requiring any person to furnish to the board information regarding the supply of power to him, including particulars of quantities, prices, terms, conditions, points of delivery, use, and by whom supplied;
>
> (c) providing for the entry upon, and inspection of property, plant and works including the making of inventories and valuations thereof, the examination of books, accounts, records, and documents relating thereto, and generally the obtaining of information in connection therewith;
>
> (d) providing for the discontinuance of the supply of power to any customer who is in default in payment of any account for power or any monthly charge levied under the on-meter efficiency improvements program under *The Energy Savings Act*, providing for the removal of the meters, wires, facilities and equipment of the corporation from the premises of the customer and providing for the allocation of, or exemption from, liability for losses, costs, damages or expenses resulting from such discontinuance or removal;
>
> (e) providing for the allocation of, or exemption from, liability for any loss, costs, damages or expenses incurred by a customer or any other person resulting from any fluctuation, interruption, reduction or failure in the supply of power;
>
> but no regulation or order made under this section shall relieve the corporation from liability for negligent acts or omissions.

Had the legislature intended terms and conditions be subject to PUB approval, it would not have given the Manitoba Hydro-Electric Board the power to pass regulations.

Regulations are a form of legislation and can only be amended in accordance with *The Statutes and Regulations Act.* The PUB does not possess the jurisdiction to establish or change Manitoba Hydro's regulations.

Manitoba Hydro also provided the PUB with information regarding its service extension practices as part of the Information Requests from past proceedings filed in PUB MFR 16 and further information in PUB MFR 18. Manitoba Hydro responded to IRs from the PUB, Coalition, GAC and MIPUG on questions and during the course of the Manitoba Hydro Workshop (Transcript pages 820-832).

The Manitoba Hydro Act again clearly places jurisdiction over the terms and conditions upon which service extensions will be made solely with Manitoba Hydro:

> **Terms and conditions of service extensions**
> 49.1 The extension or enhancement of the supply of power by the corporation to any customer shall be on terms and conditions, which may include a contribution to, or payment for, capital expenditures, acceptable to the corporation.

Unlike s. 39 (2) which makes the Corporation's authority to fix the price for power subject to PUB approval, s. 49.1 contains no such requirement with respect to obtaining contributions related to extending or enhancing the system in order to allow for the supply of power to commence. There exist two distinct concepts – s. 49.1 deals with the terms and contributions collected to recover the cost of connecting to the system in order to be in a position to receive power; s. 39 deals with the price payable for the power itself.

Considering the clear jurisdiction over the terms and conditions of service and service extension policy provided by the legislature to Manitoba Hydro, it would not be appropriate for the PUB to issue any directives related to these policies.

7.3 Net Metering

During Manitoba Hydro's workshop (Transcript pages 892-897), Chairman Gosselin posed questions to Manitoba Hydro regarding net metering. Specifically, he inquired whether net metering customers should be charged for infrastructure they use in selling power to Manitoba Hydro, and whether customers who avail themselves of DSM should also receive a credit on account of generating energy savings for Manitoba Hydro. Manitoba Hydro and its Consultant, CA provided general information in response.

On June 10, 2016, Mr. Chernick filed evidence on behalf of the Green Action Centre (Exhibit GAC-13) that included a discussion on the appropriateness of Manitoba Hydro's approach to net metering, including how the credit for energy delivered to Manitoba Hydro should be determined.

As submitted during the Pre-Hearing Conference held June 24, 2016, Manitoba Hydro views that net metering issues be excluded from the cost of service review process as parties have not had an opportunity to properly adduce or test evidence. Given issues related to net metering were excluded in the scope established in Order 26/16, it would be premature for the PUB to make any determinations or issue any directives on net metering as part of this proceeding.