MANITOBA HYDRO
COST OF SERVICE 2016

Reply Submission of the Consumers' Coalition to September 21, 2016 Submission of Intervenors

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INTRODUCTION

The Coalition appreciates the opportunity to reply to the September 21, 2016 written submissions of the Intervenors. The Coalition reply will focus on arguments it has not addressed in its September 21, 2016 submission.

In addition, the Coalition wishes to correct 2 typos found at page 34 of its September 21, 2016 submission.

1. GREEN ACTION CENTRE (GAC)

1.1 The GAC depiction of cost causation overlooks the role of judgement (pages 4-5)

- GAC takes exception to the suggestion that considerations of efficiency and rate stability have a role in Cost of Service Studies (COSS):

  > *Mr. Chernick's approach gives a clearer picture of what considerations are included in the COSS and which left out so that more explicit deliberation can occur at a GRA on how to combine cost-causal allocations with other considerations, especially efficiency, gradualism, and social consequences, to allocate the revenue requirement amongst classes. (page 5)*

  Issue

  - The Coalition begs to differ with any suggestion that Mr. Chernick's approach provides clarity or is consistent with the statutory scheme. Establishing the appropriate COSS methodology is not a simplistic exercise of separating black from white.
  - As all experts with the possible exception of Mr. Chernick have acknowledged, there is significant judgement involved in COSS analysis. In many cases, there is more than one way of approaching the question of cost causality.
  - In such situations, it is appropriate and consistent with the principle of cost causality to include considerations of efficiency and rate stability in determining the COSS methodology that will be used. Indeed, the "minimize tension" approach advocated by GAC for the treatment of DSM underscores the point that taking into account other considerations may be appropriate at the COSS stage when weighing different judgements.
  - The statutory obligation to consider relevant policy and public interest matters has already been addressed in the Coalition's September 21, 2016 submission (pages 6-7).

1.2 The proposed treatment of DSM by GAC undermines its submissions regarding cost causality

- GAC argues:

  > *The most important consideration in allocating DSM costs is to avoid causing harm to some classes while benefiting the system. In addition, to the extent possible, the cost*

allocation should minimize tension among classes in the design of DSM programs and the DSM portfolio (page 13)

Issue

- The claim that customer impacts should be the driving determination in the treatment of DSM is totally at odds with the earlier argument of GAC (page 4-5) that COSS should strictly follow cost causality and that considerations of customer impacts should be left solely to the rate design stage.
- In the case of DSM, the issue is whether we wish to recognize DSM as an integral element of integrated resource planning. If we do, then DSM should be allocated to Generation and Transmission (G and T).

2. General Service Small / General Service Medium (GSS/GSM)

2.1 Allocation of fixed costs to exports fails to recognize differential contributions to G and T costs

- GSS/GSM recommends that 62.8% of export sales should be assigned fixed as well as variable costs (page 3)
- The argument is based on the view that a portion of opportunity sales is relatively predictable and should attract fixed costs similar to dependable sales.

Issue

- This argument properly captures the view that opportunity exports "played a role" in MH development plans.
- What it misses is the point that the role played by dependable and opportunity exports is less than that played by domestic load (Coalition September 21, 2016 submission, pages 18 - 21) and that even dependable exports should not attract fixed costs of the same basis as firm domestic load.

2.2 Allocation of Net Export Revenue (NER) appears inconsistent with the admission of London Economics

- GSS/GSM argues that directly assigned cost should be included in the allocation base for NER on the grounds that these costs are an integral part of being able to serve customers (page 4).

Issue

- As acknowledged by the City of Winnipeg, there are costs such as luminaires that should not be included in the allocation base (COW September 21, 2016 submission, page 2).

- During the June Workshop, London Economics also appeared to accept that luminaires should not be in the allocation base because they are not part of the monopoly service (Workshop Transcript, pages 810-811).
- Assets such as luminaires are not "an integral" part of MH's obligation to serve. A proper application of the GSS/GSM rationale would exclude these assets from the allocation base.

3. **Manitoba Industrial Power Users Group (MIPUG)**

3.1 Treatment of Net Export Revenue (NER)

- MIPUG argues that NER should be excluded from the COSS and the resulting (pre-NER) Revenue: Cost Coverage (RCC) values be used to inform any rate rebalancing decisions. The key reasons for its argument are (pages 1-7 to 1-8):

  1) there is an ability to exclude NER from the Cost of Service study, and generate RCC ratios which are meaningful and useful for setting rates;

  2) keeping NER out of the COS is consistent with maintaining a principled, analytically accurate COS study; and ,

  3) by keeping NER out of the COS, significant class-specific advocacy for NER being credited to individual items (like the distribution system, DSM costs, URA, AEF, streetlight service drops, or the system extension costs borne directly by large industrial customers, etc.) are no longer an item of COS debate.

Issue

- With respect to point 1, while it is mathematically possible to exclude NER from the COSS and calculate pre-NER RCCs the results are not meaningful.
- Exports and export revenues are a fundamental part of MH's business model. Substantial investments are made on the basis that export revenues will benefit domestic customers through lower rates.
- The fact that the system NER is below 100% cannot be taken as an indicator that domestic customers are not paying a fair share of total cost.
- Domestic rates which drive the pre-NER system-wide RCC are set with consideration given to the need to recover costs, maintain financial integrity (i.e. net income) and the benefits of export revenues.
- All else being equal, a change in export revenues will impact domestic rate levels and the pre-NER RCCs. In such cases, higher export revenues would lead to lower domestic rates and a reduction in the pre-NER RCC. This by no means is an indicator that domestic customers are failing to cover their share of total costs or that domestic rates should be higher overall.
- With respect to point 2, MIPUG argues that NER is "revenue" and as a result does not belong in a Cost of Service Study (page 1-4). That assertion is clearly wrong.

- COSS is not just about allocating costs. It also is about allocating other revenues to customer classes so the revenue requirement to be recovered from customers classes is equal to the total costs (ie.. total revenue requirement) less the revenues earned from other sources (which will include exports). Indeed the COSS study allocates a range of other revenues to customer classes (ie Late Payment Fee Revenues).
- With respect to point 3, leaving NER out of the RCC calculation does not remove the questions of how AEF costs (which are a cost in the revenue requirement) or the statutory requirement for uniform rates should be treated in the COSS. It just means they have to be addressed elsewhere.

3.2 Export Classes and Opportunity Exports

- MIPUG argues that the currently approved approach in which both dependable and opportunity exports are allocated a full share of fixed costs should be retained (page 2-1).
- MIPUG identifies what it claims are the three arguments in favour of a separate treatment of opportunity and firm exports and then attempts to dispel each (page 2-2):

1) Opportunity sales should not be allocated fixed costs if their presence did not drive Hydro to incur fixed costs (e.g., build new generation).

2) Opportunity sales should not be allocated fixed costs since the quality of service that the customer receives is lower than that received by dependable export customers or by domestic customers.

3) Opportunity sales should not be allocated fixed costs because their presence is not certain in any given year.

<u>Issue</u>

- In addressing points 1) and 3) MIPUG argues that opportunity exports drove MH to incur fixed costs (pages 2-4 to 2-11) and that a reasonable level of opportunity exports can be relied upon (page 2-13 to 2-14). As a result, MIPUG argues that it is nonsensical to allocate only variable costs to opportunity exports.
- However, this does <u>not</u> mean that opportunity exports should necessarily be allocated fixed costs on an equivalent basis with firm load (Coalition's September 21, 2016 written submission, pages 18 – 21 - the economic perspective argument).
- MIPUG never addresses the admission by Mr. Bowman that firm sales triggered from dependable sources are a key trigger for major new projects. (Coalition's September 21, 2016 written submission, page 21).
- In addressing point 2), MIPUG agrees that service quality might be a consideration if the cost allocation was being used to set export rates but suggests that service quality is not a valid consideration in terms of how exports should be treated in the COSS (pages 2-11 to 2-13).
- This argument is – to use MIPUG's terms – nonsensical.

- If we are including an export class in the COSS in order to determine a "fair share" of the embedded cost that should be allocated to exports in conjunction with domestic customers, the only way to reasonably do so is to apply the same COSS principles as used for domestic classes.
- These principles clearly recognize differences in service quality between customer classes in the allocation of costs. To do otherwise would be inconsistent with the basic principles of cost of service.

3.3 Generation Classification and Allocation

- MIPUG recommends that Hydro follow the "longstanding industry-standard" Cost of Service methodology to explicitly distinguish generation costs into demand-related components and energy-related components within the classification step.

  Issue

  - As all parties but MIPUG appear to agree, the Manitoba Hydro approach only notionally classifies the costs as 100% energy-related. The allocation factors used (i.e. weighted energy) are intended to capture both capacity and energy considerations.
  - The MIPUG approach is a recipe for double counting.

3.4 Bipole III and Riel

- The position of MIPUG is that Hydro over uses what is typically considered a narrow exemption for the purposes of functionalizing transmission lines as generation (the Generation Related Transmission Asset, or GRTA). It suggests this practice should be curtailed.
- MIPUG claims that among the examples of overuse are Bipole III and Riel. In its view, Bipole III and Riel fail to meet a reasonableness test to be functionalized to generation as a GRTA. From its perspective, they should be functionalized 100% as transmission, and classified as demand-related (allocated based on the 2CP allocator as for all transmission) (page 4-1).

  Issue

  - As part of its rationale, MIPUG relies on a FERC definition of Transmission presented in the 1992 NARUC Cost Allocation Manual (page 4-2). However, a lot has happened since the Manual was produced including FERC Order 888 and the introduction of the open access for transmission. Manitoba Hydro has noted that under FERC tests associated with its OATT, facilities such as Riel and Bipole III would not qualify for treatment as Transmission (the Coalition's September 21, 2016 submission, page 37).
  - At page 4-3 MIPUG includes a comparison of energy-related transmission costs for various utilities which it notes was unchallenged. The lack of challenge should not be taken as acceptance given the restricted time available for questioning in both June and September.

- In terms of the comparisons shown, MIPUG fails to address the key point that Hydro's system is fundamentally different from those of Hydro Quebec and BC Hydro given that 75 percent of Manitoba Hydro's system is HVDC (the Coalition's September 21, 2016 submission, page 8 under Unique Elements).
- The MIPUG comparisons are also inadvertently misleading. The Manitoba Hydro percentages indicate the portion of the costs that are deemed to be GRTA. These will be allocated using the weighted energy allocator which captures both demand and energy considerations. On the other hand, the percentages for Hydro Quebec and BC Hydro only represent the portion of the GRTA-related transmission costs that are to be allocated on an energy basis. They do not include the portion of GRTA costs that are to be allocated on the basis of demand.
- MIPUG also references the BC Hydro map (page 4-5). It notes that the BC GRTA do not include all lines to the lower mainland. This is correct – the BC GRTA include the major lines to the interconnection with the transmission network system (which in the Peace River lines is the major load centre at Prince George). Manitoba Hydro's definition of GRTA is totally consistent with BC Hydro's definition of GRTA. Specifically, in the case of the HVDC facilities, it includes the transmission required to deliver generation to the network system. The only difference is the distances involved and nature of the facilities used (i.e., HVDC vs AC).

3.5 US Interconnections

- MIPUG recommends that the PUB reject Hydro's proposed methodology change for US Interconnection to energy-related and continue to classify US Interconnection assets the same as all other assets functionalized as transmission (ie demand-related and allocated on the basis of 2CP).

  Issue

  - One of the MIPUG complaints is that the allocation of Interconnections will not match the allocation of transmission costs under the OATT (page 5-6). As Manitoba Hydro has noted, there would be an inconsistency even if the lines were classified as demand related and allocated on a CP basis. Hydro uses a 2CP allocator while the MISO OATT uses a 12CP allocator.

3.6 DSM Treatment

- MIPUG supports Hydro's proposed method change to allocate DSM costs directly to each customer class. MIPUG recommends the PUB approve this method.

  Issue

  - With respect to the treatment of DSM as a resource MIPUG responds as follows:

    > *Mr. Harper's view and subsequent recommendation to functionalize DSM to generation and transmission and allocate accordingly is a reasonable alternative for DSM treatment in many jurisdictions. But it does not fairly reflect*

Manitoba's current situation with surplus power, low export markets, a high degree of uncertainty about the future of DSM programming and proposed new arm's length agency; some of which was addressed in cross-exam of Mr. Bowman regarding DSM costs deferring the need for future generation investment (and to a large part future transmission investment):

- MIPUG fails to address the reality that DSM is providing real benefits now and there would be shortages without it. (the Coalition's September 21, 2016 submission, page 31).
- In addition the question of how some unknown future agency might approach DSM (if ever established) is best dealt with when and if a change occurs. For now, DSM is based on least cost planning principles and should be treated with this in mind for purposes of the COSS.

3.7 Uniform Rates (URA)

- MIPUG addressed the Uniform Rates issue in its August 19, 2016 reply submission. It took the position that the URA should be excluded from the COSS. MIPUG claims that the URA "distorts the cost of service results".

  Issue

  - Actually it is not the URA that distorts the COSS from a cost causality perspective but the statutory requirement for uniform rates.
  - It is important to look to the policy underlying the legislative requirement for uniform rates in order to determine how this "distortion" should be addressed. This was the subject of the Coalition's September 21, 2016 written submission and the conclusion was that the most appropriate way to manage the URA in the COSS was to allocate it against export revenues (the Coalition, September 21, 2016 submission, page 21).

CORRECTION OF TYPOS FOUND AT PAGE 34 OF THE COALITION'S SUBMISSION

The Coalition has identified two material typos in its September 21, 2016 submissions.

At the bottom of page 34 under the heading *Recommended Order flowing from Finding 9*, the Coalition suggests the dates of January 15, 2016 (meet by January 15, 2016 with Intervenors and PUB on marginal costs study) and March 1, 2016 (file draft terms of reference for marginal cost of service study by March 1, 2016).

The Coalition concedes these dates are overly optimistic as they have already passed. In both cases, the intent was to introduce 2017 timelines (ie January 15, 2017 and March 1, 2017).