IN REGARD TO 2016 COST OF SERVICE APPLICATION

REBUTTAL EVIDENCE OF PATRICK BOWMAN

WITH RESPECT TO THE WRITTEN EVIDENCE AND WORKSHOP OF:

MANITOBA HYDRO;

WILLIAM HARPER, ECONALYSIS CONSULTING SERVICES on behalf of Consumers' Association of Canada (Manitoba Branch)/Winnipeg Harvest ("COALITION");

PAUL CHERNICK, RESOURCE INSIGHT, INC. on behalf of Green Action Centre ("GAC");

JOHN TODD, ELENCHUS on behalf of the City of Winnipeg; and

A.J GOULDING, JEROME LESLIE, and IAN CHOW, LONDON ECONOMICS INTERNATIONAL LLC ("LEI") on behalf of General Service Small (GSS) and General Service Medium (GSM)

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

August 5, 2016

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INTRODUCTION

The written rebuttal evidence of Patrick Bowman addresses the written evidence and comments in the Intervener Workshop held from June 21 - 23 for intervening parties including:

- William Harper, Econalysis Consulting Services on behalf of Consumers' Association of Canada (Manitoba Branch)/Winnipeg Harvest ("COALITION");
- Paul Chernick, Resource Insight Inc. on behalf of Green Action Centre ("GAC");
- John Todd, Elenchus on behalf of the City of Winnipeg; and
- A.J Goulding, Jerome Leslie and Ian Chow, London Economics International LLC on behalf of General Service Small (GSS) and General Service Medium (GSM).

The Rebuttal Evidence of Manitoba Hydro ("Hydro or MH") from July 29, 2016 is also addressed.

Following the format of Hydro's rebuttal evidence, subjects are organized between key issues subject of the oral hearing in September (Section 1.0) and issues addressed through written submission in August (Section 2.0).

In summary, the evidence in this proceeding continues to confirm the conclusion in the original Bowman Pre-Filed Testimony that "For the most part, Hydro's Cost of Service methods reflect standard practice for regulated utilities in North America. However, in a number of areas Hydro's methods are at the extreme end of normal practice, outside the range of practice, or are contrary to previous and repeated PUB rulings on cost allocation."[1]

1.0 ISSUES SUBJECT TO ORAL EXAMINATION

1.1 EXPORT CLASS TREATMENT – OPPORTUNITY VERSUS DEPENDABLE SALES

Hydro's rebuttal evidence addresses the matter of the treatment of opportunity versus dependable Exports in Section 1. Although the original Application only seeks to overturn the decision the PUB has repeatedly made on one question ('should opportunity exports be allocated any fixed costs?'), the rebuttal evidence intermixes a second substantive follow-up matter, that is: 'if so, should the share of fixed costs allocated to opportunity exports be the same as for a dependable sale?'. The distinction is important, as the Board's repeated ruling on the matter effectively concludes in the affirmative for both questions, however Hydro's filings to date only seek to overturn question (1). No evidence has been filed by Hydro in this process to offer a credible alternative proposal to the Board on question (2), i.e., to

[1] MIPUG-11, P. Bowman Pre-Filed Testimony, June 10, 2016, page 1-2

address: 'if opportunity exports were allocated a share of fixed costs, but to a lesser degree than dependable exports, how would such level be determined?'.

Hydro's omission of the second question in their filings to date has the tendency to result in Hydro leaping from the assertion that allocating a full share of fixed costs to opportunity exports is too high, to the conclusion that therefore there should be no fixed cost allocation. Hydro's rebuttal evidence, for the first time, provides a brief examination of some substantive matters behind question #2 – suggesting that there are Hydro-supported arguments that opportunity exports were in fact integral to the fixed cost investment decision on many plants (but perhaps not the pre-1970's plants), and further that opportunity exports may not justify the full degree of embedded cost allocation (e.g., Hydro suggests in many years it may only be 50 - 80% of the embedded cost, though in some years it was 125 - 207%[2]). As a result, Hydro continues to conclude that the "full share" concept in Hydro's view is not supported, even though the Hydro rebuttal inherently shows that some share is merited.

Hydro asserts that the position in the original Bowman Pre-Filed Testimony is that "Opportunity Sales should bear a full share of embedded Generation and Transmission cost"[3]. For clarity, this position is not in the Bowman Pre-Filed Testimony. The Bowman Pre-filed Testimony instead only seeks to assess Hydro's proposal (i.e., no share) and concludes that Hydro's justifications: (a) misstate certain facts[4], (b) appear to include no new facts or arguments that have not been previously considered and dismissed by the Board, and (c) mischaracterize the key purpose of the export class. The export class is not intended to measure the appropriate rates or value of the export service being provided, but rather the reasonable contribution that export revenues should make towards covering the costs of the fixed assets (specifically, "the opportunity sales should participate in funding the asset costs"[5]). Further, the Bowman Pre-Filed Testimony notes that Hydro's proposals are weaker today than when last rejected by the Board given the evidence from the recent NFAT about the integral nature of export revenues (both dependable and opportunity) for the decision to invest in new fixed generation and transmission assets.

This rebuttal continues to focus only on the merits of the application orders sought by Hydro – that is, the Hydro proposal that there should be <u>no</u> allocation of fixed costs to opportunity exports. Based on all evidence to date, this proposal by Hydro continues to lack support, and should be rejected. If Hydro were to instead provide a firm proposal to question #2; that is, to propose a share of fixed costs that is less

[2] Manitoba Hydro Rebuttal Evidence, July 29, 2016, Table 1: Average Actual Opportunity Export Prices compared to Average PCOSS G&T Cost, page 6

[3] Manitoba Hydro Rebuttal Evidence, July 29, 2016, page 5.

[4] MIPUG-11, P. Bowman Pre-Filed Testimony, June 10, 2016, page 35 – for example, Hydro's evidence suggests that exports are a temporary feature of new plants. In fact the exports at issue, opportunity sales, are a permanent feature of new plants – it is the dependable sales that are a temporary feature that decline as the load grows.

[5] MIPUG-11, P. Bowman Pre-Filed Testimony, June 10, 2016, page 35.

than a "full share" to assign to opportunity exports, that proposal could be assessed. However, based on the facts presented to date, it appears such a proposal would at most reduce the "full share" by a near insignificant amount related to the relatively smaller book value investment arising from the initial investment in the pre 1970s generation and transmission assets, and even this approach is unlikely to be considered to be of merit under close scrutiny.

There are three further specific matters raised in Hydro's rebuttal evidence regarding opportunity versus dependable exports that require comment:

1. **Citation of Order 7/03 (2003):** Hydro asserts that the only position taken contrary to Hydro's proposal is Mr. Bowman. In this regard, Hydro misportrays that the Board too has repeatedly rejected the arguments of Hydro that opportunity sales should not be assigned any share of fixed costs. Hydro further misportrays the Board's earlier rulings, suggesting at page 3 of their rebuttal that in Order 7/03 (from 2003) the Board directed an approach that excluded fixed costs from being allocated to opportunity sales (i.e., suggesting the Board conclusion is in support of Hydro's current position). This is not accurate. In Order 7/03 the Board rejected the arguments being made at that time by Hydro that no export sales (dependable nor opportunity) should be allocated fixed costs. The Order in no way suggests a need to move to allocate less costs to exports (as is now advocated by Hydro), it was an Order oriented towards increasing the allocation of costs to exports compared to the approach in place at that time. Hydro also ignores that the total effect of that 2003 Order was entirely adverse to Hydro's current position, in that the Board ordered that no share of exports, be it through cost responsibility nor Net Export Revenue (NER), be allocated to any portion of Hydro's costs except the Generation and Transmission system, noting:

> In Order 64/94, the Board stated at page 33, "...Hydro's method of allocating net export revenues is appropriate for Hydro's system, because it proceeds from the principle of cost responsibility rather than mere judgment." The Board further stated "... that it would be inappropriate to allocate any portion of export revenues as an offset to distribution costs within the central system or to costs in the Diesel Zone."
>
> The Board has heard no new evidence at the current hearing to support or justify a departure from the principles of cost causation previously adopted for allocating net export revenues. Because export revenues arise from generation and transmission capacity, the Board believes that it continues to be appropriate

> to allocate the net export revenues derived from that capacity in proportion to class responsibility for generation and transmission costs.[6]

In short, the new citation of Order 7/03 in no way supports Hydro's current position that costs allocated to exports should be reduced from that last ordered by the Board, nor that any residual Net Export Revenue should be credited to all systems including the distribution system (as is now practiced by Hydro). If Hydro were to adopt the methods as set out in Order 7/03 (i.e., that no NER be allocated to systems outside of Generation and Transmission), the net effect on the current proceeding would be an overwhelming reduction in the scale of issues associated with enumerating the appropriate allocation of costs to the export class[7].

2. **Rationale for Assignment of Costs to the Export Class:** The issue at hand today, as has been apparently accepted by all experts in this proceeding, is not determining what exports should be paying (exports will pay what the market will bear), but what costs exports should be contributing towards, and therefore for which domestic customers should not be paying. Exports should participate in, and be allocated a share of, all costs that are incurred within the development business plan, in full or in part on the basis, or with the reasonable expectation, of earning the export revenues. In this way, opportunity power exports are no different than firm power exports – each is integral to the business plan to proceed with all major generation and transmission developments and improvements, and each is therefore integral to funding the capital and ongoing costs of the asset. There is fundamentally only one determinative question to be answered – 'does Hydro incur fixed (i.e., bricks and mortar) costs for generation and transmission assets at least in part on the premise that they will be used by, or used to earn revenues from, opportunity sales?' The answer is clearly yes. As a result there is a firm basis to assign fixed costs against opportunity export sales.

3. **"Value" of Opportunity Power:** With respect to opportunity sales, Hydro is correct when they refer to these sales as being effectively of a lower market value product than dependable sales. For a market participant, it is fully expected that a customer buying short-term power that could be interrupted at times of low water flows would expect to pay a lower price than a customer

[6] Board Order 7/03, February 3, 2003, page 97.

[7] This is because the current emphasis arises from the fact that of the total export revenue, the dollars are carved up in two primary ways – those that go to fund generation and transmission costs (the Export Class costs), and those that go to offset generation, transmission and distribution (the NER). Due to the distribution-related mismatch, determining the precise breakdown is important to the ultimate cost allocation to each class. If NER were not used to offset (what is sometimes referred to as "subsidize") the Generation, Transmission and Distribution costs, but only applied against Generation and Transmission costs, as was the case in 7/03, then there would be much less practical relevance to the precise enumeration of the Export share of costs, as, in effect, the export dollars in both pools of revenue are allocated in much the same manner.

buying power deemed more firm and reliable and provided over the long-term. However, this is not the basis for including an export class in the Cost of Service Study, as the class costs are not used to determine export pricing. As accurately stated by Hydro, "The purpose of the Export Class is to determine a reasonable share of Generation and Transmission cost to exclude from cost responsibility borne by the domestic rate classes"[8], on the principle that this share of investment is inherently related to, and intrinsically expected to be paid by, export revenues. An irony in Hydro's position is that, though opportunity sales are of lower value and firmness, they are in fact of greater permanence to the decision to invest in capital intensive hydraulic plants than dependable, as opportunity power will be taken to market in about 99 years out of 100 over the plant's life, while dependable sales will generally be a transient feature of the plant investment decision, arising only during the period prior to the power being needed for domestic supply[9].

The only other testimony to offer a substantively different view than Hydro on the matter of Opportunity versus Dependable exports was provided by Goulding, Chow and Leslie (London Economics). The approach adopted by London Economics is not in agreement with Hydro, in that London Economics analyzes the pattern of dependable versus opportunity sales based on relatively recent history (since 2005/06 in original submission, since 2000/01 in Undertaking #35) and concludes that opportunity sales are in fact more firm or "predictable" over this time horizon than suggested by Hydro. As a result, London Economics indicates 63.8% of export sales[10] should have fixed costs assigned to them based on their predictability, rather than the approximately 50% used by Hydro. There are two observations necessary on the London Economics approach:

1) In terms of the competing concepts of "dependable" versus "predictable" sales, in analyzing a hydraulic system, the pattern of water flows is such that even the 16 year history in the updated London Economics material (Undertaking #35) is too short for assessing the dependable nature of power availability. Hydro's approach is more appropriate for determining what power will be dependable and what will not qualify as dependable in any given future year, in that Hydro uses the full hydraulic record of approximately a century.

2) Regardless, the London Economics team is conceptually correct in that for Cost of Service purposes, opportunity sales cannot be viewed as whimsical, unpredictable, take-them-as-you-can-get-them sales. These sales are a predictable part of Hydro's economic reality over the long-term. A Cost of Service is based on allocating the costs of long-term assets, whose underlying

[8] Manitoba Hydro Rebuttal Evidence, July 29, 2016, page 4

[9] Opportunity power is not typically of use to Manitoba regulated customers, unless firmed by other sources.

[10] GSS/GSM Undertaking #35, Reduced from 66% originally recommended in evidence based analyzed years since 2005/06.

> investment decisions effectively treat the opportunity power as fully predictable[11], and integral to the decision to invest in fixed costs. In this regard, even sales that Hydro classifies as "opportunity" and non-firm in a given year are absolutely predictable that they will occur in large quantities over the life of an asset investment.

In short, if London Economics had used the full long-term record to consider the predictability of opportunity sales in relation to Hydro's investment decisions, their conclusion should appropriately be that effectively all opportunity sales quantities are predictable, and fully expected to help fund the fixed assets, and presumably therefore should be allocated fixed costs in the Cost of Service study.

1.1.1 NO EXPORT CLASS

Hydro's rebuttal evidence addressed the issue of no export class in the Cost of Service Study, suggesting it was raised in the Bowman Undertaking #33 as a possible change to expert opinion. Manitoba Hydro is mistaken. Undertaking #33 was a request for the interim positions of MIPUG as the client. Undertaking #33 is not a revision or update to the positions taken in the Bowman Pre-Filed Testimony.

It is worth noting from Hydro's rebuttal evidence Table 2[12] that elimination of the export class from the Cost of Service in today's context has relatively little impact on RCC ratios, while at the same time resolving a significant range of issues being debated at this hearing (more than half of Hydro's rebuttal evidence on issues going to the oral examination deals solely with export allocation while the remainder of their rebuttal evidence deals with the functionalization and classification or assets that heavily impact the allocation of costs to exports). Hydro's evidence accurately portrays that in a different context (such as a time of very high export prices combined with lower Hydro embedded costs, as existed in 2006), an export class may have a larger practical importance. Given today's facts, the practical impacts of an export class, as compared to the complexity of issues it drives, is a fair matter for the Board to consider. Bowman's Pre-Filed Testimony concludes that an export class should be maintained, and this opinion has not changed based on Hydro's rebuttal evidence, though in fairness the conclusion is not as strong as was the case when the Pre-Filed Testimony was prepared.

It is also worth noting that Table 3 in Hydro's rebuttal evidence[13] is of no meaning to the current proceeding or any credible analysis of Hydro's Cost of Service, in that this table implies that effectively all export revenues are unrelated to any of Hydro's investment costs (which is nonsensical), and is not a

[11] The specific price may be difficult to predict over the long-term but there is effectively no risk that there will be substantial quantities of opportunity power made available for sale.
[12] Manitoba Hydro Rebuttal Evidence, July 29, 2016, Page 10
[13] Manitoba Hydro Rebuttal Evidence, July 29, 2016, Page 10

position advocated for by any party in this proceeding or consistent in any manner with regulatory decisions in this province.

1.1.2 NET EXPORT REVENUE

Hydro's rebuttal analysis on Net Export Revenue is not inconsistent in any way with the material in Bowman Undertaking #32, in regard to the net effect of calculating Revenue:Cost Coverage (RCC) Ratios in the near-term. Hydro's analysis however uses PCOSS14-Amended, which has been designed to ensure that almost all classes are within the 95%-105% zone of reasonableness. In that environment, the net impact of any decision to not include the NER in the Cost of Service study is small.

The response to Undertaking #32 however shows the impact of removing the NER from consideration in the Cost of Service study when using the recommended COS methods, such as a single export class and other proposals from the Bowman Pre-Filed Testimony. This table is repeated below for clarity:

Table 1: Table 2 from MIPUG Undertaking #32: RCC Ratios before NER and Surplus/shortfall balances reflecting Bowman Pre-Filed Testimony

Customer Class	Total Cost ($000)	Class Revenue ($000)	Revenue:Cost	Surplus/(Shortfall)
Residential	619,285	567,599	91.7%	(51,686)
General Service - Small Non Demand	127,685	133,251	104.4%	5,567
General Service - Small Demand	131,172	135,647	103.4%	4,475
General Service - Medium	187,075	186,756	99.8%	(319)
General Service - Large 0 - 30kV	91,775	84,956	92.6%	(6,819)
General Service - Large 30-100kV*	55,398	57,808	104.3%	2,410
General Service - Large >100kV*	179,694	189,258	105.3%	9,563
Area & Roadway Lighting	21,937	21,386	97.5%	(551)
Total General Consumers - Rate Setting	**1,414,021**	**1,376,660**	**97.4%**	(37,361)

Table 1 above shows that under this set of COS methods consistent with past Board Orders and with the Bowman Pre-Filed Testimony, the NER credited back to the domestic interconnected customer classes is $37.361 million (i.e., domestic interconnected classes are only paying 97.4% of the costs allocated to them). The table also shows that before any allocation of NER, four of the eight classes are already being charged rates that exceed their full share of costs, and the remaining four are receiving all of the benefit of all of the NER, plus the benefit of the added revenues from the four classes that are overpaying. The best outcome to address this situation is above average increases starting with those classes below 95% RCC (particularly Residential and GSL 0-30 kV), and then bringing all classes ultimately to 100%, reaching a point where the NER is no longer serving to offset a portion of today's costs. At that time discussions can occur about the best way to benefit ratepayers via the use of the now-surplus NER (preferably

focused on the stability of rates both within the natural water cycle of droughts and high water, as well as when large capital projects come into service). Such an outcome would not be on the regulatory agenda however until, for example, the residential class had seen differential rate increases (as a class) on the order of 9% higher than the systemwide averages ($51.686 million in added revenue on a $567.599 million revenue base). Whether this arose from all customers or from perhaps added revenue from future inverted rates would be a rate design matter for a subsequent hearing, not Cost of Service.

1.2 CAPACITY COSTS REFLECTED IN MARGINAL COST WEIGHTED ENERGY APPROACH

Hydro's rebuttal evidence continues to reject any classification of generation costs to demand; continuing to suggest that a marginal cost weighted approach already includes a substantial demand allocation[14]. However, the marginal cost weighted approach has no ability to measure demand in the classic concept – that is, the impact on the system of usage over a short but acutely peaking time period. The marginal cost weighted energy only measures the concept of "peak" over extremely broad time periods comprising many hundreds of hours (671 hours for summer peak, 661 for winter peak)[15]. Comparing the difference in the winter peak approach used for Coincident Peak allocation (average over 50 hours[16]) to that used in the marginal cost weighted energy approach (average over 661 hours) for the interconnected domestic customer classes shows the difference noted in the Table below:

Table 2: Winter peak contribution for 50 hours averages versus 661 hour averages[17]

	Coincident Peak Approach		Marginal Cost Approach		*Difference*	
	Over top 50 hours		Over 661 hours			
	Winter Demand (MW) average	Winter Peak Contribution	Winter Demand (MW) average	Winter Peak Contribution	*Change in MW*	*Change in Peak Share*
Residential	1,775	42.3%	1,484	39.4%	*- 291*	*-3.0%*
GSS - ND	335	8.0%	297	7.9%	*- 38*	*-0.1%*
GSS - D	397	9.5%	363	9.6%	*- 34*	*0.2%*
GSM	564	13.5%	526	14.0%	*- 38*	*0.5%*
GSL 0 -30 kV	277	6.6%	267	7.1%	*- 10*	*0.5%*
GSL 30 - 100 kV	187	4.5%	177	4.7%	*- 10*	*0.2%*
GSL > 100 kV	638	15.2%	641	17.0%	*3*	*1.8%*
Area & Roadway Lighting	18	0.4%	12	0.3%	*- 6*	*-0.1%*
Total Domestic Interconnected	**4,191**		**3,767**		***- 424***	

[14] Manitoba Hydro Rebuttal Evidence, July 29, 2016, pages 16 - 22

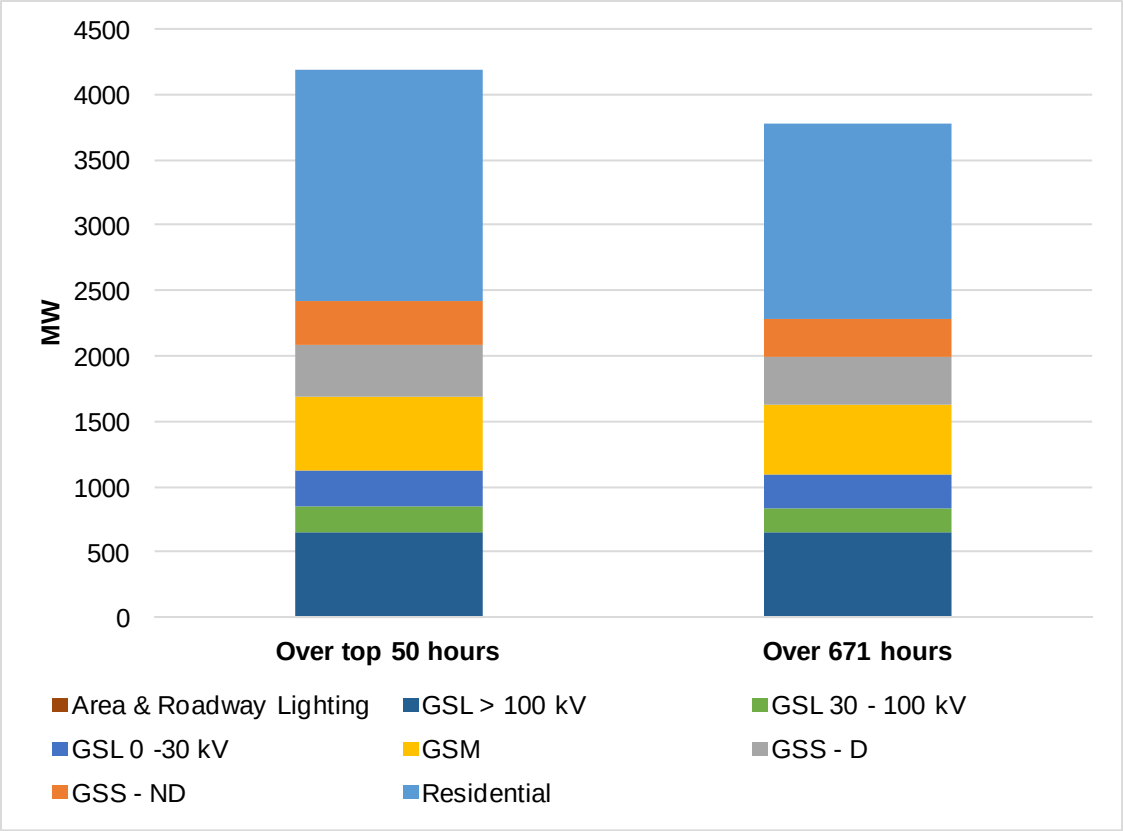
[15] See PUB/MH-I-31a-c page 5.

[16] 50 hour values are taken from PCOSS14-Amended, page 24.

[17] Data from PCOSS14-Amended Schedule D1 for Over top 50 hours, page 24 and PUB/MH-I-31a-c for Over 661 hours, page 5.

Table 2 above highlights that measurement of an acute peaking time period of 50 hours results in domestic customer loads totalling 4,191 MW, of which Residential customers make up 42.3% of the peak load. Once this concept is muted to the 661 hour average, the total load for allocating costs drops to a peak of only 3,767 MW, of which residential have significantly decreased to only 39.4% of the load. The above table also highlights that the net effect of using this broadly averaged peak over 661 hours, rather than a 50 hour peak, results in substantially less relative costs being allocated to Residential and more costs to all General Service customers from GSS-Demand through GSL >100 kV. The same data is presented graphically in Figure 1 below, highlighting the minimal MW impact from the difference on every class except GSS and Residentials, who see their acute winter peak effect highly muted (though on a relative basis the GSS share slightly grows while only the residential share shrinks):

Figure 1: Winter peak by class, in MW[18]



There is little doubt that with respect to utility planning and operation, a peak load difference of over 400 MW drives added costs and investment. Under Hydro's proposals, all generation asset costs, as well as a very large percentage of transmission costs, Bipole costs, converter station costs, and interconnection line costs are allocated without any reference to the winter peak load over the top 50 hours of 4,191 MW.

[18] Data from PCOSS14-Amended page 24 and PUB/MH-I-31a-c page 5.

The marginal cost weighted approach only considers the average winter peak over 661 hours of 3,767 MW[19] peak (a full 424 MW below the more acute 50 hour average peak) and even then only assigns this time period a relative weighting that will be further muted by averaging this weighting with shoulder and off-peak periods. For this reason, it is not credible to suggest that the Hydro marginal cost approach has any substantive allocation based on the high loads arising at peak times.

A comparable Table and Figure for summer peak loads is provided below, showing a similar pattern of ignoring 236 MW of load that drives the 50 hour acute summer peaks.

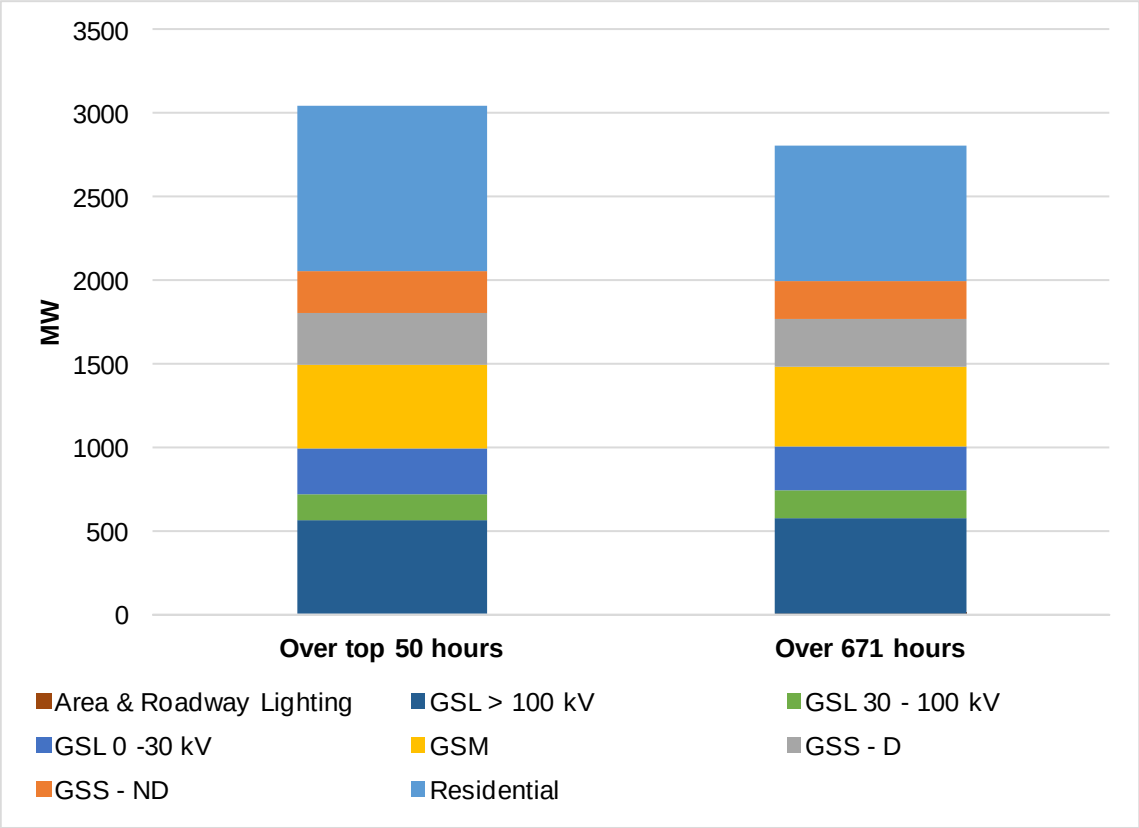
Table 3: Summer peak contribution for 50 hours averages versus 671 hour averages[20]

	Coincident Peak Approach		Marginal Cost Approach		*Difference*	
	Over top 50 hours		Over 671 hours			
	Summer Demand (MW) average	Summer Peak Contribution	Summer Demand (MW) average	Summer Peak Contribution	*Change in MW*	*Change in Peak Share*
Residential	990	32.49%	810	28.8%	*- 180*	*-3.7%*
GSS - ND	256	8.39%	236	8.4%	*- 20*	*0.0%*
GSS - D	301	9.87%	281	10.0%	*- 20*	*0.1%*
GSM	506	16.62%	478	17.0%	*- 28*	*0.4%*
GSL 0 -30 kV	276	9.05%	266	9.5%	*- 10*	*0.4%*
GSL 30 - 100 kV	155	5.10%	161	5.7%	*6*	*0.6%*
GSL > 100 kV	563	18.48%	577	20.5%	*14*	*2.1%*
Area & Roadway Lighting	-	0.00%	1	0.0%	*1*	*0.0%*
Total Domestic Interconnected	**3,046**		**2,810**		***- 236***	

[19] Mathematically the E12 allocation uses the above usage values combined with the relevant portion of export sales in the same time periods.

[20] Data from PCOSS14-Amended Schedule D1 for Over top 50 hours, page 24 and PUB/MH-I-31a-c for Over 661 hours, page 5.

Figure 2: Summer Peak by Class, in MW[21]



It is also worth noting that even in the 2 CP demand allocation, for Cost of Service purposes Hydro already mutes the true extreme peaks of specific highly loaded hours by averaging over 50 hours. This is a reasonable approach, but already is a net benefit to the classes that tend to be more peaking (such as Residential customers). This approach also stands in contrast to Hydro's approach when analyzing the role of and need for investment in assets such as Bipole III (e.g., rebuttal evidence pages 23-24) which includes the extreme individual peak hours as part of the drivers for investment (i.e. the investment may be driven fewer peak hours than the 100 used in the average calculation for the 2 CP demand allocation). Many utilities use such individual peak hour load estimates for Cost of Service purposes, which would be even more acutely focused on Residentials than the 50 hour 2 CP measure recommended in the Bowman Pre-Filed Testimony.

1.3 BIPOLE III AND GENERATION-RELATED TRANSMISSION ASSETS (GRTA'S)

Hydro's rebuttal evidence adds new information in regard to the planning for Bipole III and how a lengthy loss of Bipoles I and II in summer would cause substantial outages of nearly comparable

[21] Data from PCOSS14-Amended page 24 and PUB/MH-I-31a-c page 5.

magnitude to the previously referenced winter outages[22]. The analysis hinges on Hydro's assumption that no imports would be used to cover the loss if it occurs in summer (even on an emergency basis).

Hydro's rebuttal fails to deal with the fundamental issue of Hydro's overall proposal - that is, that the Hydro proposal would treat Bipole III as a 100% energy-related resource, which it is not. The industry standard for cost of service practice includes wires and substations as transmission assets, and classifies transmission assets to peak demand (whether winter peak, or a mix of winter and summer peak). Only under relatively rare exceptions would this practice be varied.

For example, the BC Hydro survey referenced in Mr. Bowman's Pre-filed Testimony at footnote 27, page 23 (which Hydro now acknowledges includes "reasonable comparators for Manitoba Hydro"[23]) shows methods for classification of transmission assets for five utilities which own transmission plant, of which three of the five use a 100% demand classification solely. Similarly, the NARUC manual on Electric Utility Cost Allocation cites six methods to consider for classifying and allocating transmission assets, of which five are different approaches based on 100% demand (the other is the 'Average and Excess Demand' method which is a mixed demand:energy method).

The BC Hydro survey does not deal with Hydro Quebec Transmission assets per se, as these components are paid for through an O&M charge, not as a plant in service rate base asset. The BC Hydro survey also does not include the Crown owned power generator in Newfoundland and Labrador (Newfoundland Hydro) but only the largely distribution utility Newfoundland Power. Reviewing the recently filed Cost of Service analysis for Hydro-Quebec and Newfoundland Hydro, along with BC Hydro (which are the most comparable utilities in Canada to Manitoba Hydro) shows the following comparison:

[22] The Manitoba Hydro Rebuttal Evidence, (July 29, 2016) suggests the summer peak loads for 2015 at approximately 3,300 MW compared to the supply availability at only 2,200 MW would leave an 1,100 MW shortfall in the worst hour. MH Exhibit 21 page 2-6 shows the winter deficit at approximately 1,400 MW.

[23] Manitoba Hydro Rebuttal Evidence, July 29, 2016, page 20.

Table 4: Comparison of GRTA components of Crown Owned Hydro Dominated Utilities in Canada[24]

$ Millions	Total Transmission Revenue Requirement ($000s)					Network/ Customer Connection (Demand)	GRTA (Energy/ Demand)		Interconnection (Energy/ Demand)	
	Total Transm.	Demand Classified	***Demand share %***	Energy Classified	***Energy share %***	Demand Classified	Demand Classified	Energy Classified	Demand Classified	Energy Classified
BC Hydro (Proposed for F2016)	**837.7**	819.5	***97.8%***	18.2	***2.2%***	794.4	25.1	18.2		
Newfoundland Hydro (2015 Test Year)	**42.6**	37.7	***88.7%***	4.8	***11.3%***	33.6	4.2	4.8	-	-
Hydro-Quebec Distribution (as of 2015-07-30)	**2,807.9**	2,135.3	***76.0%***	672.6	***24.0%***	1,629.4	437.4	581.6	68.5	91.0
Manitoba Hydro 2009/10 (PCOSS10)	**195.4**	131.9	***67.5%***	63.5	***32.5%***	131.9	-	63.5	-	
Manitoba Hydro 2013/14 (PCOSS14-Amended)	**293.0**	144.0	***49.2%***	149.0	***50.8%***	144.0		140.2		8.8
Manitoba Hydro 2021/22 (PCOSS14-Amended methods - estimate for 2021/22)	**723.5**	176.6	***24.4%***	546.9	***75.6%***	176.6	-	423.3	-	123.6

As highlighted in the Table 4, the practice across the three other comparable utilities varies widely, from an energy share low of 2.2% (BC Hydro) to a high of 24.0% (Hydro-Quebec). The recent Manitoba Hydro data from 2009/10 was already outside of these bounds, weighted to energy at 32.5%. The effect of Hydro's current proposals raise this percentage dramatically, to 50.8% based on assets in service today, up to a full 75.6% once Bipole III, the Great Northern Transmission Line and the Manitoba-Minnesota Transmission Project are complete. In short, the effect of Manitoba Hydro's proposals is to take Manitoba Hydro's current methods (e.g., the PCOSS10 values) which are already high by the standards of these other utilities, and instead drive the Manitoba Hydro results substantially outside any reasonable range of practice among comparables. This highlights that Hydro's approach to classifying a wide range of GRTAs,

[24] BC Hydro for Fiscal Year 2016 as proposed in 2015 Rate Design Application. Network Transmission is total transmission costs from Schedule 2.1: Classification of Transmission Function. Deducted from this Schedule is Internal Allocations (GRTA, SDA) made up of $43.3 million GRTA allocation, functionalized as Generation and classified to demand and energy in Schedule 2.0: Classification of Generation Function [line Internal Allocations (GRTA, SDA)]. Note: Transmission total differs from Bowman pre-filed testimony page 24 as it does not include the revenue deduction for Powerex and BC Hydro Point-to-Point intersegment charges. Available online: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-rda-appendices.pdf (downloaded file has COSS excel file attached as 20_01_RDA_APPX_E.xlsx). Newfoundland Hydro based on proposed Exhibit 13: Cost of Service Study 10-July-2013 (not including Specifically Assigned Customer costs). Total costs equals sum of Functional Classification of Net Book Value Schedule 2.3A multiplied by rate of return on ratebase (6.817% from Schedule 1.1) plus Functional Classification of Operating & Maintenance Expense from Schedule 2.4A plus Functional Classification of Depreciation Expense Schedule 2.5A. Available online: http://www.pub.nl.ca/applications/NLH2013GRA-Amended/files/application/NLH-2013-GRA-Application-Volume-2-AMENDED-2014-11-10.pdf . Hydro-Quebec distribution from Decision R-3933-2015, Table 9c, dated July 30, 2015, HQD-12, document 3, page 18. Available online: http://publicsde.regie-energie.qc.ca/projets/317/DocPrj/R-3933-2015-B-0046-Demande-Piece-2015_07_30.pdf . Manitoba Hydro PCOSS10; sum of Schedules C6, C9, 11 and C12 - GRTA includes generation functionalized Transmission Facilities/Costs; Network includes transmission functionalized Transmission Facilities/Costs. Manitoba Hydro for PCOSS14-Amended from PUB/MH-I-70a-c for 2013/14; GRTA consists of Existing HVDC includ. Dorsey and AC Collector incl. switching stn; Interconnection includes Existing US Interconnection and MISO fees; Network consists of Transmission. Manitoba Hydro from PUB/MH-I-70a-c for 2021/22; GRTA consists of Existing HVDC including Dorsey, AC Collector incl switching stn, BPIII and Riel Converter Station; Interconnection includes Existing US Interconnection, MMTP, GNTL and MISO fees; Network consists of transmission and Riel 230/500kV station.

as well as US Interconnections, fully to energy is excessive and not within the range of normal regulatory best practice.

With the added Hydro rebuttal evidence regarding Bipole III and the effects on summer peaking, it may be appropriate to consider a 2 CP classification and allocation for Bipole III (compared to the 1 CP method advanced in the original Bowman Pre-Filed Testimony). This would be a simplification over the proposals in the Bowman Pre-Filed Testimony, as the asset and related converter stations now only need be included as a normal transmission asset (which are already classified and allocated on a 2 CP basis). Fundamentally, though, this new evidence does not ultimately support Hydro's claim that the best representation of the costs of Bipole III is average marginal cost weighted energy over the entire year (as opposed to usage at more peak times, as occurs with a 2 CP allocator).

1.4 DORSEY CONVERTER STATION

Manitoba Hydro's rebuttal provides new information that appears to contradict previously provided evidence in regard to the Dorsey converter station. For clarity, the rebuttal evidence notes that the Bowman Pre-Filed Testimony was correct in the understanding that the Dorsey DC converters have long been, and continue to be, functionalized as transmission for the purposes of the Open Access Transmission Tariff (OATT). This is the tariff that is used to charge third parties for the use of Hydro's transmission system, as well as a tariff that is paid by Hydro's own long-term sales (though in that case both the payee and the payor are Manitoba Hydro)[25].

For the current proceeding, the Hydro proposal is to change the Dorsey converter station from a transmission functionalization to a generation functionalization. Such a change would lead to both a revised PCOSS method for setting domestic rates as well as a resulting changed approach to calculating the OATT. As a result, use of Hydro's transmission system by third parties, as well as by Hydro's own long-term exports, would see a materially lower cost[26].

The confusion for the present record is that Hydro had to date implied an opposite rationale sequencing – that the Dorsey converter station was already not included in the OATT, and that this was a driver and rationale for excluding Dorsey from the transmission function in PCOSS14-Amended[27]. This same sequencing was apparently relied upon by Mr. Harper in his workshop presentation, where he notes a

[25] See May 11 Workshop transcripts, page 207.

[26] As per the footnote 49 of MIPUG-11, P. Bowman Pre-Filed Testimony, the OATT currently included Dorsey converter in the tariffable assets, and this comprises approximately half of the depreciation included in that tariff and a third of the Operating and Maintenance costs. If Hydro's new proposed approach is adopted, this would suggest the OATT tariff would decline by likely on the order of 40%.

[27] E.g., see Coalition-37 which notes that Dorsey is "ineligible for inclusion in the transmission tariff" failing to note that this conclusion only arises in the event PCOSS14-Amended is adopted with the proposed new Dorsey refunctionalization.

rationale for functionalizing Dorsey to generation in PCOSS14-Amended due to it being "non-tariffable"[28] (i.e., failing to reflect that Dorsey only becomes non-tariffable due to its treatment in PCOSS14-Amended).

This new evidence would appear to strengthen the conclusion in the Bowman Pre-Filed Testimony that the Dorsey converter station should continue to be included in transmission. This is based on the following new perspectives:

1) Dorsey has been and continues to be included in the Open Access Transmission Tariff as a transmission asset, since at least the 2001 hearing.

2) Changing methods to include Dorsey in generation would materially reduce the rates under Hydro's OATT charged to third-parties so that these transactions would not be allocated any costs for the Dorsey converter assets, despite benefitting from those assets (through the avoided need for alternative expensive transmission equipment which would clearly be tariffable).

3) Hydro's own long-term exports would be charged a lower OATT which would tend to make the exports appear more profitable (though this has zero net impact on Hydro's net income since it is on both ends of this transaction).

A further consideration is the previously uncited relevance of the PUB's decision regarding PCOSS14-Amended to the setting of OATT rates, and how this might overlap with any other approvals required from the PUB for changes to OATT rates for power service provided within Manitoba. The Hydro rebuttal evidence only notes that the newly proposed "non-tariffable" classification of the Dorsey converters is only expected to take effect "once the next PCOSS is released" at which time Hydro suggests the utility itself will update the OATT rates as part of the "regular OATT rate update"[29].

1.5 INTERCONNECTIONS

Hydro's rebuttal addresses the classification of interconnections, which Hydro proposes to change to 100% marginal cost weighted energy, from the current 2 CP demand allocation. Hydro's rebuttal indicates that the interconnections are appropriately classified to energy as they serve to move energy in all hours, ignoring that this same rationale applies for all transmission (the vast majority of which is classified based on demand, not energy).

[28] COALITION-17, Workshop presentation of Mr. Harper, June 21, 2016, page 13.
[29] Manitoba Hydro Rebuttal Evidence, July 29, 2016, page 25.

In addition, Hydro provides evidence that is purported to show that the OATT approach based on 12 CP is not a materially different allocator than a weighted energy approach. This is not supported by the table attached to Hydro's rebuttal evidence (Table 7, page 27), which shows that a 12 CP allocation leads to GS Large >100 kV customers paying for 15.3% of costs, as compared to 16.9% under the Hydro-proposed weighted energy approach, and 14.3% under the current 2 CP approach (which is supported in the Bowman Pre-Filed Testimony). If the evidence is that these differences are immaterial, then it is not apparent why Hydro would propose a relatively unusual allocation approach for a significant proportion of its transmission system. For example, as noted in Table 4 above, by 2021/22 Hydro's proposed use of this new interconnection category will be approaching in magnitude the total assets considered grid transmission[30]. The only other utility that appears to use an interconnection functionalization is Hydro Quebec, but the HQ interconnection revenue requirement is about 10% of the size of the network/grid transmission component[31]. BC Hydro appears to make no use of such an interconnection categorization at all. Further this breakdown is also contrary to Hydro's own characterization that: "The vast majority of transmission assets are grid transmission, which is the backbone system which links generation facilities and major load centres and over which power can flow in either direction."[32] Hydro's proposed methods, as shown in Table 4 above, will lead to only 21% of Hydro's wires and substations being considered "grid transmission"[33] which is far below being "the vast majority" as suggested.

2.0 ISSUES ADDRESSED THROUGH WRITTEN SUBMISSION

2.1 SUBTRANSMISSION COST TREATMENT

Mr. Chernick, on behalf of the Green Action Centre, indicates that Hydro's use of the subtransmission function is "arbitrarily" [34] allocating certain lower voltage components to a subset of the classes, and that it would be appropriate to allocate subtransmission to all customers, including those served at high voltages that do not use the subtransmission function. This approach is without merit and inconsistent with the most basic of Cost of Service best practices.

There is near-universal and longstanding agreement in COS best practice that customers served off of bulk transmission at high voltages should not be allocated the costs of lower voltage systems (such as subtransmission and distribution). For example, the NARUC Cost of Service Manual notes that: "Cost responsibility for subtransmission plant is usually assigned to only those loads served directly at the subtransmission voltages and those distribution loads fed through subtransmission facilities. Customers

[30] $123 million versus $177 million.
[31] $160 million compared to $1,629 million
[32] Manitoba Hydro Rebuttal Evidence, July 29, 2016 page 27.
[33] $147 million out of a total $723 million revenue requirement.
[34] GAC-13, Evidence of Paul Chernick, June 10, 2016, page 39.

served at voltages higher than subtransmission are not allocated these costs on the theory that the subtransmission facilities are not required or used to provide the higher voltage services."[35]

Manitoba Hydro's rebuttal provides four accurate and appropriate responses in support of rejecting Mr. Chernick's proposal. Further, both Hydro and Mr. Chernick accurately note that Hydro already has a means to allocate to all customers any lower voltage components which happen to be required for general grid purposes (specifically to get generation to the transmission grid to generation, via GRTAs), and as such this is not a rationale for allocating other forms of subtransmission to customers who do not use these voltages.

Mr. Chernick's evidence also concludes that subtransmission should not be solely classified to customer classes served at lower voltages, as some of the customers within these lower voltage classes do not use the subtransmission system given the customer's particular geographic location. This ignores that Manitoba has a requirement for uniform geographic rates such that it is irrelevant whether an individual member of that customer class is in a location that happens to step directly down from high voltage transmission to low voltage distribution (i.e., with no subtransmission), or whether their location also has a step where mid-voltage subtransmission is used to deliver their power. An analogy might suggest that Vale in Thompson should not be allocated any costs of Bipoles I and II, being located in the north near the major generation, but this is clearly similarly not sensible and inconsistent with the Manitoba uniform rates requirement.

Finally, Mr. Chernick's evidence suggests that subtransmission represents a "savings" to the system since it at times eliminates the need for additional >100 kV lines[36]. This assertion is also not consistent with the facts. Many industrial users have substantial portions of their plants using power at voltages from 4,800 volt and higher. Their power is delivered at >100,000 volts and it is the customer themselves that owns the necessary transformation and delivery systems to serve their needs. In the case of the smaller Hydro customers, the equivalent transformation and delivery systems are the subtransmission and distribution system, which should be paid by the customers who make use of those lower voltage delivery locations (just as the industrial customer pays directly for the equivalent service within their own plant). There is no "savings" to the GSL>100kV class from Hydro adding to its subtransmission and distribution system, there is only added services provided that are not of benefit to the GSL>100kV class and as such should not be charged against their usage.

[35] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, (January, 1992), page 73.
[36] GAC-13, Evidence of Paul Chernick, June 10, 2016, page 39.