Review of Manitoba Hydro's cost-of-service methodology on behalf of the small and medium general service customer classes

prepared for Hill Sokalski Walsh Olson LLP

June 10th, 2016

Upon review of Manitoba Hydro's ("MH") current cost-of-service ("COS") methodology, it is recommended that a greater portion of fixed costs be attributed to the export class, the allocation basis of net export revenue be expanded to include direct costs, Demand-side management ("DSM") costs be spread across all customer classes, and revenue cost coverage ("RCC") ratios be considered in subsequent rate applications. These recommendations are based on the fundamental principles of efficient rate-design. In particular, where possible, costs should be borne by those who are directly responsible for causing them, minimizing cross-subsidization.

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Figure 1. List of Acronyms

List of Acronyms	
BOMA	Building Owners and Managers Association of Manitoba
CME	Canadian Manufacturers & Exporters Manitoba Division
COS	Cost-of-Service
DR	Demand Response
DSM	Demand Side Management
EE	Energy Efficiency
GSS	General Service Small
GSM	General Service Medium
HSWO	Hill Sokalski Walsh Olson
IFF	Integrated Financial Forecast
LEI	London Economics International
MH	Manitoba Hydro
MIPUG	Manitoba Industrial Power Users Group
NER	Net Export Revenue
NFAT	Needs For and Alternatives To
PUB	Public Utilities Board
RCC	Revenue to Cost Coverage
SD	Standard deviation
SEP	Surplus Energy Program
ZOR	Zone of Reasonableness

1 Background

1.1 Introduction

The current Manitoba Hydro cost-of-service ("COS") methodology review is the first of its kind in over a decade. In its January 22, 2016 letter, the Public Utilities Board ("PUB") appointed Hill Sokalski Walsh Olson LLP ("HSWO") as legal counsel for the general service small and medium ("GSS/GSM") customer classes.

London Economics International ("LEI") has subsequently been retained by HSWO to provide independent evidence to assist the PUB in understanding the views and positions of the GSS/GSM customers in this proceeding. Given this mandate, this paper presents LEI's analysis of rate design issues from the perspective of GSS/GSM customers and proposes amendments to the existing COS methodology to improve its alignment with generally accepted rate making principles.

LEI submitted questions and participated in the Manitoba Hydro COS workshop held from May 11th to 13th, 2016 and has taken into consideration feedback from Manitoba Hydro at the workshop, and its responses to information requests and undertakings in the preparation of this submission.

1.2 Inter-class collaboration and stakeholder engagement

In its February 16th, 2016 order, the Board encouraged intervening parties to collaborate where possible to minimize any duplication of efforts and costs.[1] Accordingly, LEI met with City of Winnipeg consultant John Todd in Toronto on May 6th, 2016, to discuss observations from the COS model and to identify shared arguments between the Area & Roadway Lighting customers and the GSS/GSM customer classes. This collaboration allowed for the efficient use of time during the Manitoba Hydro COS workshop through the avoidance of repetition.

On May 13th, 2016, LEI and HSWO also met with Manitoba Industrial Power Users Group ("MIPUG") consultants Patrick Bowman and Melissa Davies and its legal counsel Antoine Hacault in Winnipeg. Similar to the collaboration with the City of Winnipeg, this meeting sought to identify shared arguments between MIPUG and GSS/GSM customer classes.

On June 3rd, 2016, LEI and HSWO hosted a web conference with GSS and GSM stakeholders including representatives from the Building Owners and Managers Association of Manitoba ("BOMA"), the Manitoba Hotel Association and the Canadian Manufacturers & Exporters ("CME") Manitoba Division. This meeting provided an additional opportunity to canvass and to discuss the key issues facing GSS/GSM customers, as well as an opportunity to provide stakeholders an overview of the possible views and positions on the COS methodology review.

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[1] Manitoba Hydro. *Order No. 26/16*. February 26, 2016.

2 Principles of rate design and cost causation

In its December 4th, 2015, COS Methodology Review, Manitoba Hydro stated that its ratemaking framework adheres to and is driven by the general principle of cost causation. Cost causation is the idea that costs should be borne by those who are directly responsible for them. This is not only a matter of fairness, but also of sending a price signal to the consumer which encourages efficient resource utilization. Cost causation principles are implemented by classifying costs based on defined service characteristics and using cost-causative allocation methods and factors.

Further, Manitoba Hydro has identified the following six rate design principles as its cost of service goals:

i. recovery of total revenue requirement;

ii. fairness and equity;

iii. rate stability and gradualism;

iv. efficiency in the sending of appropriate price signals regarding the cost of energy;

v. competitiveness of rates; and

vi. simple to understand and execute.[2]

Rate Design Principles

Financial stability and fair rate of return: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a fair return and generating sufficient cash flow to support necessary investment.

Non-discrimination: Similarly, situated customers should face similar terms and conditions. Whereas competition in theory will assure that customers with similar tastes and preferences face a similar set of choices, in a regulated environment such an outcome is assured only through enforcing non-discrimination in rate design.

Incentives compatibility: Rate design should where possible provide appropriate incentives to both the utility and consumer. Depending on the circumstances of the particular jurisdiction, the behavior desired by policymakers may change (i.e. incentivizing greater participation in demand-side management programs); this in turn may affect the rate design chosen.

Cost causation and avoidance of cross-subsidies: One of the most fundamental principles of utility rate design is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross subsidies (either between or within customer classes) could be avoided.

Administrative simplicity and transparency: Rates should be straightforward for customers to understand. Complex rate designs increase costs to consumers, and may result in more time being spent proving that the rate design is fair to all customers.

Source: Bonbright. Principles of Public Utility Rates, Public Utility Reports Inc., Arlington, 1961.

[2] Manitoba Hydro. *Cost of Service Methodology Review*. December 4, 2015.

The ratemaking goals put forward by Manitoba Hydro are consistent with wider industry practice. The textbox on the previous page outlines key rate design principles from *Principles of Public Utility Rates* by Bonbright *et al*, which closely tie-in with Manitoba Hydro's stated goals. However, in some aspects the rate design in Manitoba needs to be adjusted to adhere to these goals.

Within the scope of this cost of service methodology review, LEI has considered all of the above principles generally and, specifically, from the GSS/GSM customer perspective. It is important that revenue requirements are met, and the adjustments in rate design identified would continue to achieve that goal. However, it is also important that the cost burden of this requirement is shared fairly amongst all customer classes. Where possible, costs need to be allocated to customers that are specifically responsible for causing particular capital investments, operation and maintenance costs, while costs that result in broadly shared benefits need to be socialized.

To some degree, a level of trade-off exists between the rate design principles. For example, the goal of administrative simplicity may be compromised in pursuit of fairness and non-discrimination. Although it is important to strike a balance between of these goals in undertaking a cost of service study, the order in which they are presented by Manitoba Hydro also show their relative importance. The following recommendations generally revolve around the principle of fairness and equity, but do not violate any of the other principles.

3 Issues to consider when assessing Manitoba Hydro's cost-of-service methodology

There are four key issues identified by LEI and associated recommendations that would improve the application of COS methodology in Manitoba from the GSS/GSM customer perspective. These recommendations have been constructed in line with key principles of rate design and cost-of-service as outlined in Section 2.

The following table briefly outlines the issues that are currently disadvantaging GSS/GSM customers.

Figure 2. Table of issues and LEI recommendations

Issue	Status Quo	LEI Recommendation
Allocation of fixed costs to export sales	Assigned to 50% of export sales	Assign to 66% of export sales
Allocation of net export revenue	Based on share of allocated costs	Base on share of allocated and direct costs
Treatment of DSM costs	Directly allocated to participating classes	Classify as demand and allocate using the D14 2CP allocator
Revenue cost coverage	RCC for GSS customers above the zone of reasonableness	To be corrected in subsequent rate application

Firstly, while labeled "opportunity", to a degree, a minimum level of opportunity exports was accounted for and expected in the initial justification for construction of the assets, and should bear a corresponding share of fixed costs. Fixed costs should be allocated to the export class using a confidence interval around historical and forecasted export levels; this is more representative of the expected minimum level of exports, and thus the level of exports which "caused" the fixed costs to be incurred.

Secondly, the current exclusion of direct costs from the allocation of net export revenue is not consistent with the principle of fairness and should be replaced by a more holistic measure of total costs. This approach minimizes unfair allocation between customer classes and abides by the fundamental principles of ratemaking.

Thirdly, classification of DSM costs as demand and allocation through the COS allocator is more appropriate than the current practice of direct allocation to participating classes. The entire system benefits from avoided system peak demand costs, and therefore, these costs should be shared by all users of the system.

Lastly, the revenue to cost coverage ("RCC") ratio for GSS/GSM customers is significantly outside of Manitoba Hydro's Zone of Reasonableness ("ZOR"). Rates for all customer classes need to be adjusted appropriately to properly collect target revenues. This would be to ensure that cross-subsidization between customer classes is minimized and that they adhere to the principles of cost causation.

3.1 Allocation of fixed costs to export sales

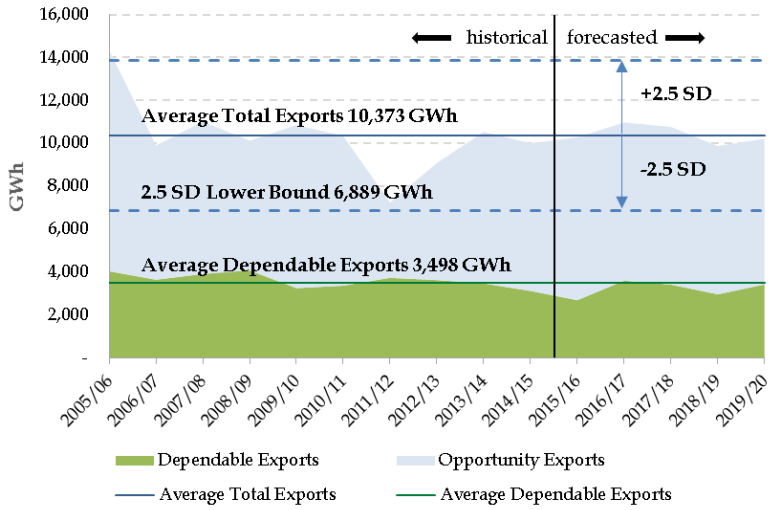
Manitoba Hydro assigns full embedded generation and transmission costs, representative of the associated fixed and variable costs, to the determined level of dependable exports. Opportunity

exports however are only assigned incremental or variable costs. Currently, MH's COS methodology defines the opportunity to dependable export split as 50:50.[3]

The lack of fixed costs assigned to opportunity exports under the existing cost of service methodology conflicts with previous positions of Manitoba Hydro. When asked during the workshop about the role of opportunity exports in the advancement of generation investments, Manitoba Hydro Division Manager of Power Sales & Operations Mr. David Cormie stated that *"because you're building it a little earlier you're attracting a long-term firm sale, and you're attracting then some additional revenues from the opportunity market for the surplus that that plant might provide."*[4]

The ability to secure firm export contracts is cited as the motivation for the advancement of generation investment. However, in the Needs For and Alternatives To ("NFAT") Manitoba Hydro's Preferred Development Plan Manitoba Hydro assumes that all surplus electricity can be sold either as long-term firm energy or as on-peak and off-peak opportunity sales.[5] Since the acceleration of this generation investment was justified under the assumption of sustained export sales, it effectively assumes that opportunity export sales are not sporadic, but are a reliable source of income. Therefore, given cost causation principles, opportunity exports need to pay a portion of fixed costs.

Figure 3. Historical and forecasted exports by type



Note: Forecasted dependable and opportunity exports are based on projected dependable and average water flows respectively. *Source: Manitoba Hydro. Undertaking #5*

[3] Based on energy available under dependable water flows compared to average water flows for years 3 to 8 of the Integrated Financial Forecast ("IFF") Manitoba Hydro. *Cost of Service Methodology Review*. December 4, 2015.

[4] Manitoba Public Utilities Board. *Re: Manitoba Hydro COSS Workshops. May 11, 2016.*

[5] Public Utilities Board. *Report on the Needs For and Alternatives To (NFAT) – Review of Manitoba Hydro's Preferred Development Plan*. June 2014.

Figure 3 depicts the 10-year historical and 5-year forecasted exports. Note that between 2005 and 2015, total export sales have never been lower than 7,244 GWh, which is more than double the projected 3,498 GWh average amount of dependable export sales. The figure also shows confidence intervals which are 2.5 standard deviations (SD) from the mean of total exports. The lower bound of this confidence interval represents a 1 in 162-year likelihood that total exports would fall below this threshold, yet it is still above the historical dependable exports. This analysis confirms that opportunity export sales are not speculative, but can actually be considered reliable.

LEI proposes a statistical approach whereby Manitoba Hydro uses the lower bound of the 2.5 SD confidence interval of total exports to set the portion of exports paying fixed costs. Over the full 15-year period, Manitoba Hydro average export sales are projected at 10,373 GWh with a 2.5 SD lower bound of 6,889 GWh, equivalent to 66% of average total export sales. In other words, 66% of total export sales should be considered dependable. Under this approach, 34% of export sales would be treated as opportunity and be allocated variable costs only.

A 66% fixed cost allocation to the export class on the basis of a 2.5 SD lower confidence bound of historical and forecasted export levels is appropriate for cost of service purposes. This is equivalent to assigning fixed costs to 16% of opportunity export sales.

3.2 Allocation of net export revenue among customer classes

In its COS methodology review submission, Manitoba Hydro noted that "*weight is also given to fairness and efficiency objectives. The allocation of Net Export Revenue ("NER") on the* ***basis of total cost*** *to serve results in an improvement in the equitable sharing of export revenue between customer classes."*[6]

However, upon further examination of the COS model, LEI determined that net export revenues are not allocated among the different customer classes based on total costs attributed to a customer class, but rather on the basis of allocated costs. Allocated costs flow through the functionalization, classification and allocation steps of COS. This was confirmed by Manitoba Hydro during its cost-of-service workshop held from May 11th to 13th, 2016. Manitoba Hydro Cost of Service Manager, Ms. Kelly Derksen stated that, "*Yes. You're correct. Direct costs are excluded from the allocation of net export revenue.*"[7] Direct costs are those that do not flow through the amended PCOSS-14 model; they are directly assigned to particular classes that they can be linked to on the basis of cost causation.

LEI disagrees with Manitoba Hydro's stance on this issue and recommends that net export revenue should be allocated on the basis of total costs, which includes direct costs. The rationale for doing so should be on the basis of fairness, objectivity and equity, as consumers in specific customer classes would not be able to be served if investments and expenditures that are

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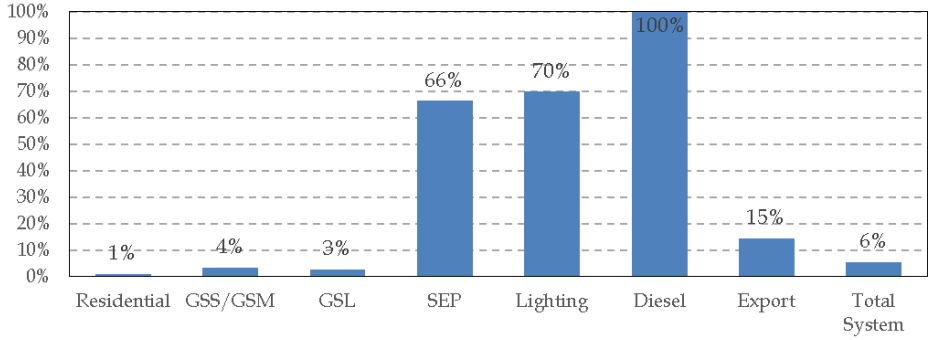
[6] Manitoba Hydro. *Cost of Service Methodology Review.* December 4, 2015.

[7] Manitoba Public Utilities Board. *Re: Manitoba Hydro COSS Workshops. May 11, 2016.*

directly attributable to these customer class are not being made. Since these costs are an integral part of being able to serve customers, they should be considered when spreading net export revenue among classes to subsidize their rates. As noted by Manitoba Hydro, the introduction of the export class and current allocation of NER aimed to address the fairness issue related to export revenue offsetting generation and transmission costs prior to 2005. The inclusion of direct costs would build on this, addressing the relatively unfavorable treatment of customer classes with significant direct costs.

Rate designs may be viewed as unfair when they select only certain costs to be considered when determining that allocation of net export revenue. While direct costs only account for 5.5% of Manitoba Hydro's total $1.8 billion revenue requirement, they represent a more substantial share of individual customer class costs. As seen in Figure 4 below, the total cost for Lighting has a substantial share of direct costs at 70%, followed by SEP at 66% and GSS/GSM customers combined share of 4%. Residential and GSL have the lowest shares of 1.1% and 3%.[8] Lighting, GSS and GSM customer classes have a greater share of their costs attributed as direct costs, and are hence receiving a smaller portion of the net export revenue relative to the revenue they have to raise. It is important to note that Diesel costs, despite being directly assigned, receive a portion net export revenue.

Figure 4. Percentage of costs for each customer class that are direct costs



Source: Model of PCOSS-14 Amended

On being asked about fairness considerations being taken when allocating net export revenue on the basis of allocated costs, Manitoba Hydro said, *"It essentially amounts to the fact that we have certain customers on our system that have infrastructure in place that is really akin to dedicated end-use equipment. And because we define the point where service starts and stops at the meter, we've said it's appropriate to exclude those kinds of costs for a certain customer class. So we have cut it off at the point that says total allocated costs, which means costs allocated on account of generation, transmission, sub-transmission distribution, and whatever each class's allocation of those costs are is how, then, net export revenue gets applied."*[9]

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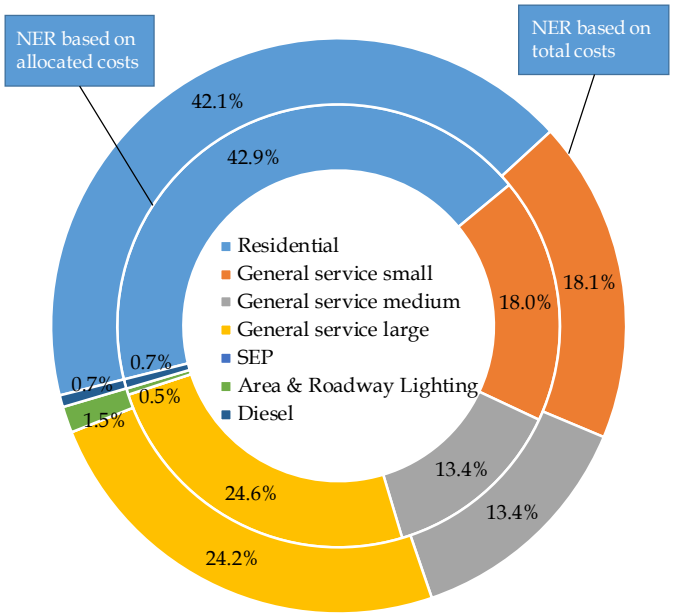
[8] Manitoba Hydro. *PCOSS14-Amended.* December 2015.

[9] Ibid.

Manitoba Hydro also acknowledged that allocating net export revenue based on total costs, i.e. allocated costs and direct costs, was an equally acceptable argument, *"I suppose one could make the argument to extend the application to dedicated end-use facilities also. We stopped it at the point of delivery, which is really just the meter, and we've said that that is reasonable."*[10]

Figure 5 shows the changes in net export revenue assigned to each class when the allocation methodology is changed from allocated costs only to total costs. The table following shows the corresponding changes in RCC ratios for each customer class when these same changes are applied. The increase in net export revenue to GSS/GSM customers and Area and Roadway Lighting would allow for a greater portion of their revenue requirement being fulfilled, and subsequently lower rates being charged to them.

Figure 5. NER and RCC shares when NER is based on allocated costs vs. total costs



Customer Class	RCC when NER is based on allocated costs	RCC when NER is based on total costs
Residential	99.90%	99.60%
General service small	106.25%	106.30%
General service medium	99.30%	99.30%
General service large	96.47%	96.37%
SEP	85.40%	85.40%
Area & Roadway Lighting	100.30%	104.50%
Diesel	72.60%	72.50%

Source: Manitoba Hydro

The current exclusion of direct costs from the allocation of net export revenue is not consistent with the principle of fairness and should be replaced by a more holistic measure of total costs.

[10] Ibid.

3.3 Treatment of Demand-side management costs

Demand-side management ("DSM") programs involve the planning, implementing, and monitoring activities of electric utilities which are designed to encourage consumers to modify their level and pattern of electricity usage.[11] DSM is often separated into two groups: (i) energy efficiency ("EE") and (ii) demand response ("DR"). EE aims to reduce the electricity consumption during all hours of the year in order to permanently reduce the demand for energy and concentrates on end-use energy solutions.[12] DR plays a significant role in shifting electricity usage away from peak periods in response to time-based rates or other forms of financial incentives. Manitoba Hydro has launched a series of programs for residential, commercial and industrial customers since as early 1993.[13] The associated utility costs of DSM programs are directly attributed to individual participating customer classes.

Manitoba Hydro's direct assignment of DSM costs to participating customer classes in its cost of service methodology conflicts with the system-wide benefit derived from a reduction in system peak demand costs. This system-wide benefit has been acknowledged by Manitoba Hydro as "*reductions in domestic demand have contributed to electricity surpluses, which have been sold on the export market to support lower domestic rates for Manitoba consumers, reduce greenhouse gas emissions, and defer the need for new Manitoba resources*."[14] Since the benefits of DSM are not confined to the customer class providing the DSM, the costs should be divided across all customer classes to more closely align costs with beneficiaries.

Further, the benefits of DSM are consistent with the definition of a public good as detailed in the textbox below and, consistent with economic theory of how public goods should be paid for, the associated costs should therefore be borne by all ratepayers.

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[11] US Energy Information Administration. *Electric Utility Demand Side Management.* Last accessed: June 1, 2016. <http://www.eia.gov/electricity/data/eia861/dsm/index.html>

[12] NERC. *Data Collection for Demand-Side Management.* 2007.

[13] Manitoba Hydro. *2016/17 Demand Side Management Plan.* March 2016.

[14] Manitoba Hydro. *Coalition-MH 1-18c.*

Public Goods and Free Riders

A public good as defined by economic theory, is a good that, once produced, can be consumed by an additional consumer at no additional cost. Public goods are goods that can be consumed by everybody in a society or nobody at all. They cannot or will not be produced for individual profit, since it is difficult to get people to pay for its large beneficial externalities. It is helpful to think about a public good as one with a large positive externality. Public goods are both *non-excludable* and *non-rivalrous* in that non-payers cannot be effectively excluded from use and where use by one user does not reduce availability to others. Common examples of public goods include defense, public fireworks, lighthouses, clean air and other environmental goods, and information goods, such as software development, authorship and invention. Public goods often create free-rider problems, in which people not paying for the good may continue to access it, which in turn results in the goods being overused and ultimately under-produced.

In order to minimize the social inefficiency of free-riders, it is important to identify a public good appropriately and either put in place barriers to access (if possible) or ensure a mechanism by which those individuals that access or have the potential to access it are also bearing the cost of the public good.

Source: A Theory of Public Goods by Randall G. Holocombe.

During the workshop, Manitoba Hydro Cost of Service Manager Ms. Kelly Derksen stated that, in the view of Manitoba Hydro, direct assignment of DSM costs is *"the most cost causal approach"* and that it *"aligns the cost of the programs with the classes that participate."* However, participating in a DSM program is not the same as benefiting from it. The benefit of avoided peak demand costs resulting from DSM programs accrues to customers both within and outside the customer class which provides the DSM.

Instead, LEI proposes that DSM costs flow through the cost of service process classified as demand and allocated using the existing D14 2CP for Domestic and Dependable Export table across all customer classes. Under this approach, cost responsibility is spread across all customer classes on the basis of contribution to system peak demand. This aligns with cost causation principle – peak demand is the primary driver of the need (and costs) to manage peak demand using DSM.

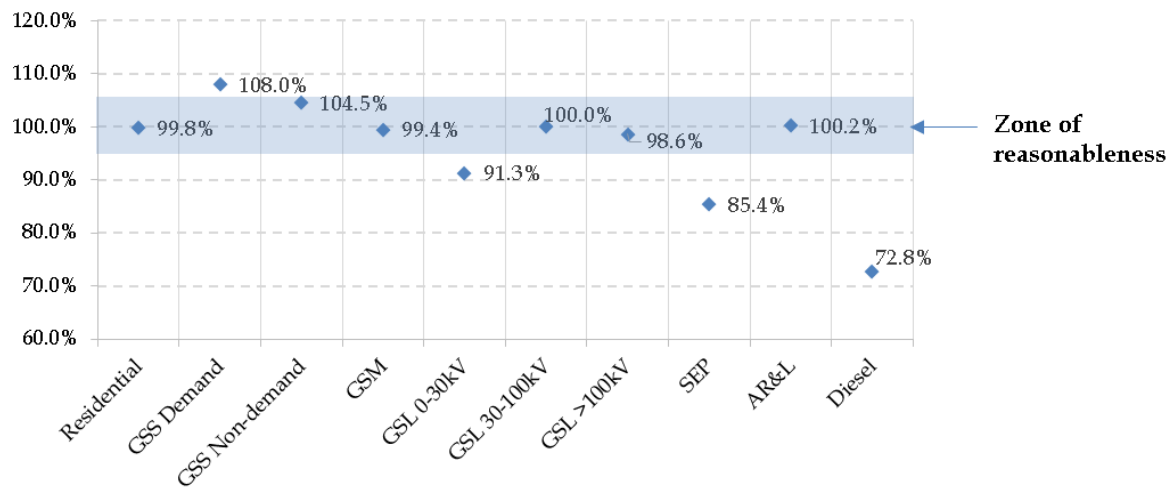
LEI finds that the classification of DSM costs as demand and allocation through the COS allocator is appropriate in view of the avoided system peak demand costs. Since DSM provides a public benefit, the associated costs would be better shared by all customers.

3.4 Revenue cost coverage

Manitoba Hydro's COS determines each class's total allocated costs, which are then converted into rates. Rates times class specific billing determinates (volumes and number of customers, for example) results in revenues. Revenues received from each class (including their allocated share of net export revenue) divided by total allocated costs results in a RCC ratio. RCCs are used to aid in the evaluation of rate levels, and are an indicator of whether a class is reasonably paying its full share of costs. An RCC of 100% indicates that a customer class is exactly providing the same amount of revenue as the costs associated with serving that class. In this case, there is no cross-subsidization between customer classes and cost causality, one of the key principles for fair and efficient ratemaking.

Manitoba Hydro defines a ZOR for a classes' RCC as being between 95% to 105%. In its cost-of-service methodology review application to the Board, it recognizes *"a ratio outside of the ZOR as a factor to be considered in the possible differentiation of rate increases."* Figure 6 below shows the RCC ratio for all customer classes. It is particularly noticeable that GSS, GSL 0-30kV, SEP and Diesel are well outside of MH's defined ZOR.

Figure 6. RCCs for each customer class



Source. Manitoba Hydro. Model of PCOSS-14 Amended

Customer classes with an RCC above 100% would be effectively paying to the cover costs allocated to other customer classes. Likewise, an RCC less than 100% indicates that the customer class may not be charged rates sufficiently high enough to cover its allocated costs. Figure 6 depicts the RCCs for each customer class in the current COS methodology. It is important to note that there are two key customer classes that have a large upward deviation from the ideal 100% RCC, namely GS Small Non-Demand and GS Small Demand. The former's RCC is at 108% which is in fact outside of Manitoba Hydro's ZOR, and the latter is close to the ZOR upper boundary. On the other hand, Diesel, Surplus Energy Program ("SEP") and GS Large 0-30 kV are significantly lower than the 100% ideal RCC ratio. It is fair to conclude that given the current rates being charges, GS Small customers are subsidizing rates for all classes with an RCC less than 100%, violating cost causality principles and resulting in cross-subsidization between customer classes.

Figure 7. Revenue to cost coverage across different customer classes

Customer Class	RCC %	Amended RCC %
Residential	98.6%	99.8%
General Service - Small Non Demand	107.7%	108.0%
General Service - Small Demand	104.9%	104.5%
General Service - Medium	100.1%	99.4%
General Service - Large 0 - 30kV	91.9%	91.3%
General Service - Large 30-100kV	101.7%	100.0%
General Service - Large >100kV	101.0%	98.6%
SEP	0.0%	85.4%
Area & Roadway Lighting	99.7%	100.2%
Diesel	0.0%	72.8%
Export	0.0%	100.0%

Source: Manitoba Hydro Model of PCOSS14

Several pre-asks, which are part of the exhibits, were submitted in advance of the May 11-13 workshops. Pre-ask 2 and 10 are particularly relevant to this issue, where LEI asks Manitoba Hydro and the Board to consider the rationale behind Manitoba Hydro's current ZOR, as well as whether it is appropriate for certain customer classes to have an RCC above and below the prescribed ZOR.[15]

LEI would also like to draw attention to the fact that the past four prospective cost of service studies show that general service small non-demand customers have experienced incrementally higher RCCs, all above the 105% ceiling target. Likewise, general service large 0-30kV have seen successively lower RCCs in the past three studies, all below the 95% floor target. The RCC for GSS customers deviates by too great a degree from the ZOR. Consequently, rates for all customers need to be appropriately adjusted in the next general rate application in order to prevent cross-subsidization between classes. Under the current cost of service methodology and rates, cross-subsidization exists between the customer classes.

This point has been identified at the previously conducted workshop and the importance of reducing rates and correcting RCCs with respect to the GSS/GSM customers must be underscored at the next general rate application.

[15] Hill Sokalski Walsh Olson. *GSS/GSM Pre-Asks.* May 9, 2016.

4 Appendix A: List of Works Consulted

Bonbright. *Principles of Public Utility Rates, Public Utility Reports Inc.*, Arlington, 1961.

Christensen Associates Energy Consulting. *Review of cost-of-service methods of Manitoba Hydro: Supplemental Report.* August 10, 2015.

Hill Sokalski Walsh Olson. *GSS/GSM Pre-Asks.* May 9, 2016.

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Manitoba Hydro. *Electricity definitions.* Last accessed: April 12, 2016. <https://www.hydro.mb.ca/regulatory_affairs/definitions.shtml#electricity>

Manitoba Hydro. *Order No. 26/16.* February 26, 2016.

Manitoba Hydro. *Prospective Cost of Service Study – For fiscal year ending March 31, 2014 – Amended.* December 2015.

Manitoba Public Utilities Board. *Re: Manitoba Hydro COSS Workshops. May 11, 2016.*

Manitoba Hydro. *Undertaking #5.* May 30, 2016.

National Association of Regulatory Utility Commissioners. *Electric Utility Cost Allocation Manual.* January, 1992.

North American Electric Reliability Corporation. *Data Collection for Demand-Side Management.* 2007.

Public Utilities Board. *Report on the Needs For and Alternatives To (NFAT) – Review of Manitoba Hydro's Preferred Development Plan.* June 2014.The Public Utilities Board. Order No. 26/16 – Procedural Order in respect of Manitoba Hydro's Cost-of-Service Study Methodology Review. February 26, 2016.

US Energy Information Administration. *Electric Utility Demand Side Management.* Last accessed: June 1, 2016. <http://www.eia.gov/electricity/data/eia861/dsm/index.html>

5 Appendix B: LEI credentials

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm's roots stem from the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and government on policy initiatives, market and tariff design, asset valuation, market power, and strategy in virtually all deregulated markets worldwide.

5.1 Selected relevant experience

LEI has conducted rate design and cost of service studies for numerous clients along with counseling governments and regulators to design tariffs that allocate costs in an economically efficient manner.

5.1.1 Cost Allocation Experience

Distribution cost allocation and customer class definition: LEI, in consortium with an engineering firm, analyzed the customer density and distribution service costs for one of Ontario's largest utility. This engagement had three specific objectives: (i) evaluate the relationship between customer density and distribution service costs; (ii) assess whether utility's existing density-based rate classes and density weighting factors appropriately reflect this relationship; and (iii) consider, qualitatively, the appropriateness and feasibility of establishing alternative customer class definitions.

Transmission cost causation study: LEI was engaged to prepare a transmission cost causation study for the AESO. The study will be incorporated into, and filed with, the AESO's 2014 tariff application, which is expected to be submitted to the Alberta Utilities Commission ("AUC" or "Commission") on June 30th, 2013. LEI performed functionalization of transmission costs into bulk, regional, and point-of-delivery ("POD") functions using three methods: by voltage, by economics, and by megawatt-kilometer ("MW-km"). Classification into demand and energy related costs has been performed using the minimum system approach.

Self-funding tariff for ISO New England including cost causation study: LEI provided support for ISO New England throughout the design and submission to FERC of ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, frequent interaction with stakeholders, and written testimony before FERC.

Economic advice on cost causation and tariff regime: LEI provided Australia's former power market regulator, NEMMCO, economic advice on the appropriate regime for charging market participants for the costs incurred by the client in providing its services, in accordance with the National Electricity Code. In making its recommendation on participant fees, LEI considered

the criteria specified by the National Electricity Code. LEI also considered the issues and arguments raised in submissions provided by participants in response to the issues paper released in December 1999.

Tariff design for Kingdom of Saudi Arabia: Led multiple engagements with international team assessing tariff design, modeling, and electricity market evolution in Saudi Arabia; engagement resulted in a revised tariff system, including performance based rates, tolling agreements for generation, and an open access tariff. Included holding workshops for regulator in explaining cost of capital, tariff design, and other regulatory issues.

5.1.2 Rate Design Experience

PBR testimony for multiple electric utilities in Alberta: LEI provided supporting testimony for an electricity utility in its filing for a PBR plan. The testimony provided detailed data analysis (including inflation and total factor productivity ("TFP") trends), underpinning PBR economic theory, and reviewed best practices in various North American and international jurisdictions. The testimony offered back-up elements for each of the various components of the PBR plan that was being proposed by the utility. LEI also responded to the information requests by interveners and advised the client on issues raised by these interveners.

Second generation PBR in Ontario: LEI President A.J. Goulding led a $1.5 million engagement focusing on design of second generation PBR in Ontario. Key components include estimating total factor productivity ("TFP"), determining appropriateness of yardstick competition, analyzing demand-side management programs in the context of PBR, and examining service quality indicators.

Review of gas distribution PBR regimes across North American jurisdictions: LEI was engaged by Union Gas to review Union's proposed 2014 to 2018 incentive ratemaking ("IR") plan as presented to stakeholders on April 29th, 2013 and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, Union particularly requested LEI to examine approaches to a set list of ratemaking parameters: productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism ("ESM"), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas ("UFG"), and service quality indicators ("SQIs") and how they are measured. LEI was subsequently requested by Union to provide comments on Union's draft Settlement Agreement.

Incentive based ratemaking ("IBR") in Malaysia: For a large Malaysian utility, LEI has been retained to provide advice on incentive-based ratemaking in preparation for its submission to the regulator. As part of the assignment, LEI has been tasked with performing a cross-jurisdictional review of regulator instructions to utilities with regards to rate submissions. LEI will examine the Australian, UK and Philippines markets to understand the regulatory submission cycle, instructions and requirements from utilities for IBR submissions.