

**MANITOBA PUBLIC UTILITIES BOARD**

**MANITOBA HYDRO**

**COST OF SERVICE**

**METHODOLOGY REVIEW**

**EVIDENCE PREPARED BY**

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**FOR**

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**WINNIPEG HARVEST**

**(THE CONSUMERS COALITION)**

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## Table of Contents

EXECUTIVE SUMMARY .....	1
1. BACKGROUND .....	7
2. PURPOSE OF EVIDENCE .....	13
3. PURPOSE OF A COST OF SERVICE STUDY .....	14
3.1 Context.....	14
3.2 Cost of Service Principles .....	16
3.3 General Approach .....	19
3.4 Use of Results.....	20
4. MANITOBA HYDRO'S PROPOSED COST OF SERVICE METHODOLOGY .....	21
4.1 Overview .....	21
4.2 Export Class.....	22
4.2.1 Manitoba Hydro's Proposed COSS Treatment .....	24
4.2.2 ECS Comments.....	24
4.3 Revenues and Costs Used for COSS Methodology Review .....	32
4.3.1 Manitoba Hydro's PCOSS14-Amended.....	32
4.3.2 ECS Comments.....	35
4.4 Directly Assigned Costs .....	40
4.4.1 Manitoba Hydro Proposal .....	40
4.4.2 ECS Comments.....	42
4.5 Generation Function: Definition, Classification and Allocation .....	50
4.5.1 Manitoba Hydro Proposal .....	50
4.5.2 ECS Comments.....	53
4.6 Transmission Function: Definition, Classification and Allocation.....	66
4.6.1 Manitoba Hydro Proposal .....	66
4.6.2 ECS Comments.....	67
4.7 Sub-Transmission Function: Definition, Classification and Allocation .....	73
4.7.1 Manitoba Hydro Proposal .....	73
4.7.2 ECS Comments.....	74

4.8	Distribution Plant Function: Definition, Classification and Allocation .....	75
4.8.1	Manitoba Hydro Proposal .....	75
4.8.2	ECS Comments .....	76
4.9	Distribution (Customer) Service Function: Definition, Classification and Allocation .....	82
4.9.1	Manitoba Hydro Proposal .....	82
4.9.2	ECS Comments .....	83
4.10	Net Export Revenue Allocation .....	85
4.10.1	Manitoba Hydro Proposal .....	85
4.10.2	ECS Comments .....	85
5.	SUMMARY AND CONCLUSIONS .....	87
5.1	COSS Principles .....	87
5.2	COSS Methodology .....	88
5.3	Required Input Corrections .....	90
5.4	Areas for Data Input Improvement .....	90
5.5	Potential COS Model Improvements .....	91
5.6	Impact of Recommended Methodology Changes .....	92

## EXECUTIVE SUMMARY

On December 4, 2015 Manitoba Hydro filed an Application with the Manitoba Public Utilities Board for review and consideration of its Cost of Service methodology. The Consumers Coalition subsequently retained Mr. William Harper an Associate with Econalysis Consulting Services to: i) assist them with their participation in the MPUB's review of the Application and ii) to provide independent evidence that would assist the MPUB, the Coalition and other parties in understanding the reasons for and the appropriateness of Manitoba Hydro's Cost of Service methodology proposals.

The Evidence addresses the purpose of a Cost of Service Study along with the key steps and principles involved. It then reviews Manitoba Hydro's proposed Cost of Service methodology and, in doing so, notes those aspects that are considered to be appropriate as well as recommending a number of changes that should be made in terms of: i) methodology; ii) input corrections, iii) data input improvements and iv) improvements to Manitoba Hydro's modelling of its cost of service methodology.

### Cost of Service Principles

- Cost of service studies are a key part of the overall rate making process. One of their main purposes is to assist in determining a fair apportionment of a utility's revenue requirement among its customer classes. To this end, cost causation is the primary consideration in establishing cost of service methodologies.
- The determination of an appropriate cost of service methodology must also consider the other overarching objectives of rate making including encouraging efficient use of electricity, rate stability, understandability and feasibility in application.
- In terms of cost causation, while it is useful to consider the original intent/driver behind an investment more weight should generally be given to the current role that investments play in meeting customer service requirements.
- When considering the current role that a utility's investments and operating activities play in meeting customers' service requirements it is important to consider the full range of likely operating conditions and not just those that underpin the test year's revenue requirement.

## Key Areas of Agreement with Manitoba Hydro

### *Exports*

- The establishment of two export classes where the dependable export class would attract embedded costs in the same manner as firm domestic load while the opportunity class would attract only variable costs.
- Distinguishing between dependable and opportunity exports based on the forecast average (five years) dependable energy surplus to domestic needs versus the average energy available in excess of dependable energy.

### *Generation*

- The inclusion of the Dorsey (and future Riel) converter facilities in Generation as opposed to Transmission.
- The inclusion of Bipoles I & II (and future Bipole III) in Generation as opposed to Transmission.
- The inclusion of power purchases (including wind), trading desk costs, thermal fuel and all thermal plant costs in the Generation pool for allocation to both domestic load and dependable exports.
- The use of a weighted energy allocator to allocate Generation costs to customer classes (including dependable exports).

### *Transmission*

- The sub-functionalization of Interconnection costs and their allocation to domestic customers and dependable exports using the weighted energy allocator.
- The creation of a Non-Tariffable Transmission sub-function to capture those Transmission costs that are not deemed to be tariffable for purposes of the OATT<sup>1</sup>.
- The use of a 2CP allocator (based on the highest 50 hours per season) to allocate Tariffable and Non-Tariffable Transmission costs.

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<sup>1</sup> MISO's Open Access Transmission Tariff

### *Net Export Revenues*

- The allocation of Net Export Revenues to domestic customer classes based on the total costs allocated to each class, excluding direct assignments.

### Recommended Methodology Changes

#### *Revenue and Direct Assignment*

- The assignment of the revenues from Late Payment and other customer charges should be based on proportion of late payment charge revenues received (historically) from each customer class.
- Clarification is required as to the intent of the Diesel Settlement Agreement with respect to the treatment of 3<sup>rd</sup> party contributions in the COSS. However, this will have to await the filing of the finalized Settlement Agreement.
- DSM costs should be assigned directly to the Generation, Transmission and Distribution-Plant functions based on the relative values of the DSM program savings in each area.
- NEB fees should be allocated to all customer classes (including opportunity exports).

#### *Generation*

- The inclusion of an explicit capacity adder in calculation of the weighted energy allocator for Generation costs has not been sufficiently justified at this time and requires further consideration in terms of: i) whether or not one is needed, ii) what the value should be; iii) what hours/seasons it should be incorporated in; and iv) what historical years should be adjusted.

#### *Transmission*

- The allocation of the costs in the Non-Tariffable Transmission sub-function should not include exports.

### *Distribution - Plant*

- The sub-functionalization of the “common” costs such as Buildings, Communication, General Equipment and certain SCCs needs to be re-assessed.
- In the Distribution-Plant function, the COSS methodology should separate out the costs of primary and secondary facilities into two distinct sub-functions.
- The allocation base for the customer portion of the Services and Poles & Wires sub-functions needs to be adjusted in order to account for the fact that 103,000 Residential customers are in Apartments that are “served” as GSS or GSM customers.
- The GSM portion of the allocation base used for Poles & Wires needs to be adjusted to account for the different demand/customer classification for primary as opposed to secondary facilities – similar to that done for A&RL.

### *Distribution – Services*

- The customer weighting factors for Customer Service – General should be derived by applying the customer weighting factors established for each Department to the Department’s budget for the test year.

### Required Input Corrections to PCOSS14-Amended (as filed)

- Not all AC lines that serve to link generation to the transmission system have been removed from the Non-Tariffable Transmission sub-function and included in Generation.
- Manitoba Hydro has noted that specific revisions/corrections are required to the customer counts used in allocating Meter Assets, Meter Maintenance and Meter Reading costs.
- Manitoba Hydro has acknowledged that the Operating costs by function used to assign the costs associated with Buildings, Communication & Control and General Equipment to functions need to be revised.

- Manitoba Hydro has made corrections to the weights that are to be applied to the energy use by customer classes in each of the 12 SEP periods for purposes of allocating Generation costs.

#### Required Data Improvements

- The basis for the allocation factors used to assign system control costs to functions was established in 1997 and should be updated.
- The current demand/customer classification of distribution lines and transformers was established roughly 25 years ago and should be updated.
- The weights applied to the customer counts for purposes of allocating meter investment, meter maintenance and services investment have not been reviewed in 25 years and should be updated.
- The customer weightings used for meter reading should be revised so as to account for the relative effort in reading different types of meters as well as the frequency of meter reading.
- The customer weighting factors used for Billing and Collections are based on analysis done 25 years ago and need to be updated.

#### Suggested COSS Model Improvements

- The functionalization of Operating and Depreciation costs associated with Communications and Control Systems should be incorporated in the COSS model so that it can reflect any re-functionalization of assets/activities that occurs as part of the COS.
- The functionalization of Other Revenues should also be incorporated in the COSS model so that it can reflect any re-functionalization of assets/activities that occurs as part of the COS.
- The COSS model should be refined to allow for the sub-functionalization of: i) the costs associated with Settlement Cost Centres that are associated with common activities and ii) the shares of Regulated Assets, Buildings, Communication & Control and General Equipment costs that are assigned to each function. Such a



refinement would also permit the COSS model to re-functionalize these costs when assets/activities are re-assigned between functions as part of the COSS.

## 1. BACKGROUND

The last major review of Manitoba Hydro's Cost of Service ("COS") methodology occurred in 2005-2006 and was based on an application filed by Manitoba Hydro in November 2005. The review involved both interrogatories and a full public hearing during which the Manitoba Public Utilities Board ("MPUB" or the "Board") heard evidence from both Manitoba Hydro and three of the six registered intervenors in the proceeding. Following the close of the hearing, the Board issued Order 117/06 in which it made the following key findings with respect to Manitoba Hydro's COS methodology<sup>2</sup>:

- a) There should be one export customer class, rather than the two export classes (firm and opportunity) as recommended by Manitoba Hydro.
- b) Costs directly assigned to the export class are to include trading desk related costs, MAPP and MISO costs, thermal plant costs, purchased power costs and other costs that are directly attributable to exports.
- c) Generation costs will be assigned entirely on an energy basis by customer class using the twelve SEP periods, rather than the four initially proposed by Manitoba Hydro.
- d) Generation costs will be allocated to the export class similarly to the approach used for domestic classes.
- e) Transmission costs are to be allocated on the basis of demand only for both domestic and export classes as opposed to using energy to allocate interconnection costs as proposed by Manitoba Hydro.
- f) Net export revenue is to be derived through deducting from exports sales direct costs, indirect fixed and variable costs allocated to the export customer class, the estimated cost of the uniform rate program, DSM costs and forecast draws related to any fund<sup>3</sup> established pursuant to the Winter Heating Cost Control Act (Bill 11).
- g) For purposes of allocating net export revenues to domestic customer classes, all projected prospective costs are to be taken into account rather than utilizing only generation and transmission costs.

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<sup>2</sup> Order 117/06, pages 46-48

<sup>3</sup> Subsequently named the Affordable Energy Fund (AEF)

Board Order 117/06 also made a number of more general observations and findings regarding the role and preparation of COS Studies including:

- *“The Board confirms that the primary objective of COSS is to assist in the testing of the fairness of rates between domestic customer classes. This objective is met in part by the allocation of MH’s prospective revenues and expenses by customer class, in accordance with cost causation, legislation, policy and the public interest”.*<sup>4</sup>
- *“Noting the significance of the COSS, the Board prefers that the model be based on median water flows, export revenues consistent with average reservoir levels for the start of the fiscal year forecast and unit export prices reflective of “normal” conditions. While domestic consumption and prices as well as MH’s costs are somewhat predictable over the medium term, export revenues and net export revenue varies considerably while being largely outside the control of MH”.*<sup>5</sup>
- *“Supplemental information on carbon emissions costs and marginal cost are to accompany the COSS model based on historic embedded costs. The additional information will allow marginal and environmental costs to be taken into account by the Board in assessing MH’s rate proposals. RCC indices both on a pre and post-export credit basis will also be taken into consideration by the Board in establishing domestic class rates. As well, in rate setting, the Board will continue to take into account special circumstances (such as drought, high water flow, etc.); rate stability; energy efficiency objectives; and such other factors and criteria deemed appropriate and consistent with the public interest”.*<sup>6</sup>

On April 12, 2007 Manitoba Hydro filed a revised COS study utilizing the same 2005/06 forecast data as was employed for purposes of the 2005-2006 COS methodology review but incorporating the specific modifications directed in Board Order 117/06. This same methodology also formed the basis for PCOSS08<sup>7</sup> which was filed with Manitoba Hydro’s 2008/09 General Rate Application. In the subsequent Board Order 116/08 the

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<sup>4</sup> Page 56

<sup>5</sup> Page 57

<sup>6</sup> Page 46

<sup>7</sup> PUB-MFR 8

MPUB provided further clarification as to the intent of the directives flowing from Order 117/06 in that<sup>8</sup>:

- a) For thermal plant, all fuel costs and 50% of the fixed costs would be directly assigned to the Export class and this treatment would be reviewed once the pending restrictions on the Brandon plant went into effect.
- b) DSM energy savings should not be deducted from the export class but rather added to domestic load for generation cost sharing purposes.
- c) The most recent actual (not forecast) export prices should be used to establish export revenues in the COSS.
- d) Actual [eight year] energy [SEP] prices and energy use profiles should be used in the Generation weighting process.

In the same Order the MPUB directed Manitoba Hydro to<sup>9</sup>:

- a) Provide and file with the Board prior to January 15, 2009 a re-vamped Marginal Cost (MC)-COSS analysis; one reflecting needed refinements to generation, transmission and distribution marginal costs.
- b) File an economic feasibility test report with the Board by September 30, 2008, on the historical application of the service extension policy. In that report, MH was to define the underlying rationale for the existing policy, as it existed, and explain why that rationale apparently no longer exists, together with an accounting of instances (since the policy was suspended) where customers paid more to have a service connection than other previous customers.

However, in Order 150/08 the MPUB varied these directives noting that:

- Issues related to adding DSM energy savings back to each domestic class for purposes of allocating generation costs; and the use of historical, as opposed to forecast export prices to establish export revenue in the COSS are matters best deferred to MH's next GRA in order to permit MH the opportunity to study and research these issues<sup>10</sup>.

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<sup>8</sup> Pages 307-312 and 401

<sup>9</sup> Pages 401-404

<sup>10</sup> Order 150/08, page 50

- With respect to the directed Marginal Cost COSS clarification is required and the Board will agree to vary its Directive to permit Board staff and/or Advisors to meet with MH in an attempt to clarify what is being sought in a Marginal Cost of Service Study, how Marginal Cost adjustments could be made to an embedded COSS, and how Marginal Costs could be blended/added to embedded costs prior to calculation of revenue to cost coverage ratios<sup>11</sup>.
- With respect to the Service Extension Policy, the Board varied<sup>12</sup> the Directive by deleting the deadline date and the requirement for a report. Rather, and by December 1, 2008, and as part of the EIIR hearing, the Board required a written explanation from MH as to specifics of the Service Extension Policy for each class of customers served by MH. (It should be noted that Order 112/09 directed<sup>13</sup> that MH file by November 30, 2009 for Board review and approval, a new Service Extension Policy that incorporates the capital credits available to offset basic sub-transmission and distribution upgrade charges, and required capital contributions toward generation and transmission costs for set MW load additions of, say, more than 30 or 50 MW, based on proposed parameters which are on a compatible basis with the new EIIR. However, Manitoba Hydro subsequently advised<sup>14</sup> the Board that it would not be proceeding with the EIIR at that time).

In March 2009, Manitoba Hydro (in compliance with Order 116/08) filed a revised version of PCOSS08<sup>15</sup> incorporating the modifications directed by the MPUB. However, in the same filing, Manitoba Hydro expressed reservations regarding:

- The direct assignment of fixed generation costs to exports and the assignment/allocation of any fixed generation costs to opportunity exports.
- The MPUB directed treatment of DSM savings and costs.

On November 30, 2009 Manitoba Hydro filed a General Rate Application for 2010/11 and 2011/12. As part of the application Manitoba Hydro filed PCOSS10<sup>16</sup> which was

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<sup>11</sup> Order 150/08, page 51

<sup>12</sup> Page 62

<sup>13</sup> Page 139

<sup>14</sup> 2010/11 & 2011/12 GRA, Tab 13, page 3

<sup>15</sup> PUB-MFR 9

based on forecasts for 2009/10 taken from IFF08-8. This COS Study incorporated many but not all of the directives from Orders 117/06 and 116/08. The changes were primarily with respect to the costs assigned to exports and included<sup>17</sup>:

- The costs of DSM were directly assigned to the customer classes benefiting from the expenditures (as opposed to being assigned to Exports), with the exception of programs funded by the AEF which are directly assigned to Exports.
- The use of forecast export prices consistent with the IFF as opposed to recent actual prices.
- Trading desk costs as well as MISO and MAPP fees were split between Domestic and Exports as opposed to being assigned 100% to Exports.
- Gas-fired Generation was assigned entirely to Domestic load. For Brandon Unit 5, fuel and variable O&M costs were assigned to Exports, while the remaining costs were all assigned to Domestic load. However, Manitoba Hydro did indicate that for PCOSS11 all Brandon Unit 5 costs would be assigned to Domestic load in recognition of Bill 15.

Furthermore, in the filing Manitoba Hydro indicated its intention to engage external consultants to review the Cost of Service methodology<sup>18</sup>. It also noted that while PCOSS10 included one Export class, the option of two versus one Export classes was one of the issues that would be considered in the upcoming external review. During the proceeding Manitoba Hydro also filed PCOSS11 which was based on forecast for 2010/11 taken from IFF09 and utilized the same methodology as PCOSS10.

In Order 5/12 the MPUB continued to express its support for a single Export class and the need to recognize the costs associated with exports in determining net export revenue. The Board also expressed concern regarding suggestions made during the proceeding that Exports would not be assigned any of the costs associated with Bipole III. Finally, the Board also noted that there may be merit in a separate COSS review

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<sup>16</sup> 2010/11 & 2011/12 GRA, Appendix 11. See also PUB-MFR 10

<sup>17</sup> 2010/11 & 2011/12 GRA, Tab 11, pages 3-4

<sup>18</sup> 2010/11 & 2011/12 GRA, Tab 11, page 2

hearing if Manitoba Hydro is seeking changes to the currently approved Board methodology<sup>19</sup>.

In conjunction with its 2012/13 & 2013/14 General Rate Application, Manitoba Hydro filed both the results of an external COSS review undertaken by Christensen Associates Energy Consultants<sup>20</sup> and its responses to the consultants' recommendations<sup>21</sup>. It also filed PCOSS13<sup>22</sup> which was based on forecasts for 2012/13 taken from IFF11-2 and incorporated the methodology changes Manitoba Hydro had adopted as a result of the external review. Following the receipt of Manitoba Hydro's application the MPUB held a procedural conference to establish the scope of the pending proceeding and in Order 98/12 determined<sup>23</sup> that it would review Manitoba Hydro's proposed COS methodology by way of a separate process.

In conjunction with its 2015/16 & 2016/17 Rate Application<sup>24</sup> filed in January 2015, Manitoba Hydro indicated that it had initiated a stakeholder engagement process in August 2014 in order to solicit input and alternatives with respect to its COS methodology in advance of finalizing its position. Manitoba Hydro further indicated that this had led to two workshop sessions conducted on October 30, 2014 and December 12, 2014. In its subsequent Order 73/15 the MPUB indicated<sup>25</sup> that it does not expect to award any further rate increases until a Cost of Service Study (COSS) Application has been filed and the Board has sufficient time to review the COSS Application.

On December 4, 2015 Manitoba Hydro filed an Application with the MPUB for review and consideration of Manitoba Hydro's Cost of Service Study methodology. In Order 26/16, the Board determined<sup>26</sup> that it would conduct a comprehensive review of cost of service issues and that all issue including consideration of distribution, demand-side management and other future assets (e.g. Bipole III, Keeyask and the Riel converter station) would be in scope.

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<sup>19</sup> Pages 213-214

<sup>20</sup> Appendix 5

<sup>21</sup> Appendix 4

<sup>22</sup> PUB-MFR 12

<sup>23</sup> Page 18

<sup>24</sup> Tab 6, page 16

<sup>25</sup> Page 5

<sup>26</sup> Pages 15-16

The Board did determine that rate-related matters regarding rate rebalancing, time of use rates and conservation rates would be excluded from the scope of the proceeding and dealt with in the next GRA. However the Board indicated its intention to examine components of the basic monthly charge and the split between energy charges and demand charges as part of the proceeding. The Board also indicated that it intended to review Manitoba Hydro's Terms and Conditions of Service and Service Extension Policy.

## 2. PURPOSE OF EVIDENCE

The Consumers' Association of Canada (Manitoba) Inc. retained Econalysis Consulting Services to assist with its participation in the two Cost of Service workshops held by Manitoba Hydro in late 2014. Upon receipt of Manitoba Hydro's Cost of Service Methodology proposals in December 2015 the Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (jointly referred to as "The Consumer Coalition") retained Econalysis Consulting Services ("ECS") to assist and advise the two organizations regarding their participation in the PUB proceeding. As part of its engagement ECS was requested to prepare independent<sup>27</sup> evidence that would assist the PUB, the Consumer Coalition and other stakeholders in understanding the reasons for and the appropriateness of Manitoba Hydro's Cost of Service Methodology proposals.

The Evidence was prepared<sup>28</sup> by Bill Harper who, prior to joining ECS in July 2000, worked for over 25 years in the energy sector in Ontario, first with the Ontario Ministry of Energy and then, with Ontario Hydro and its successor company Hydro One Networks Inc. Since joining ECS, he has assisted various clients participating in regulatory proceedings on issues related to electricity and natural gas utility revenue requirements, cost allocation/rate design and supply planning.

Mr. Harper has served as an expert witness in public hearings before the Manitoba Public Utilities Board, the Manitoba Clean Environment Commission, the Régie, the

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<sup>27</sup> I.e., Opinion evidence that is fair, objective and non-partisan and within the area of the consultant's expertise

<sup>28</sup> Mr. Andrew Frank, a consultant with Elenchus Research Associates, assisted with the modelling of the proposed methodology changes under the direction of Mr. Harper



Ontario Energy Board, the Ontario Environmental Assessment Board and a Select Committee of the Ontario Legislature on matters dealing with electricity regulation, rates and supply planning.

He has also provided expert advice and assistance to clients in British Columbia participating in BCUC proceedings dealing with cost of service and rate design applications by both the British Columbia Hydro and Power Authority and FortisBC Inc as well as clients in Saskatchewan participating in proceedings before the Saskatchewan Rate Review Panel dealing with cost of service proposals by Saskatchewan Power. In addition he has participated in a number of Ontario Energy Board working groups dealing with cost of service-related matters.

A full copy of Mr. Harper's CV is attached in Appendix A.

The evidence starts (Section 3) by discussing the purpose of a cost of service study, the key steps and the principles involved. Section 4 deals with Manitoba Hydro's proposed Cost of Service methodology. It first addresses Manitoba Hydro's proposed treatment of exports, an issue that is rather unique to Manitoba Hydro (from a COSS perspective). Following this the evidence briefly addresses the cost base used for the methodology review; it then proceeds to deal with each of the functions (including direct assignment) Manitoba Hydro utilizes in its COSS and, finally, addresses the treatment of net export revenues. The evidence concludes (Section 5) with a summary of conclusions and recommendations.

### **3. PURPOSE OF A COST OF SERVICE STUDY**

#### **3.1 Context**

The determination of a utility's rates can be viewed as a two stage process<sup>29</sup>. The first stage focuses on the determination of the overall revenue requirement that the utility will be allowed in the test (or rate) year or, put another way, the overall rate level. At this stage consideration is given to the reasonableness of the forecast of customer energy and peak load that the utility will be expected to supply along with associated costs,

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<sup>29</sup> Charles F. Phillips Jr., *The Regulation of Public Utilities*, page 163. See also, J.C. Bonbright, *Principles of Public Utility Rates*, page 66

including the return on investors' capital where applicable. When it comes to these costs the focus is on whether the costs are necessary, reasonable and prudently incurred in order to provide the utility's customers with safe and reliable service.

The second stage is the "rate making stage" where the individual rate schedules for the utility's customers are determined such that they will (collectively) cover the revenue requirement. There are a number of objectives/principles that come into play at this stage. Drawing on a number of sources, in 1961 Bonbright set out the following as the criteria of a desirable rate structure<sup>30</sup>:

1. The related, "practical" attributes of simplicity, understanding, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
  - a. In the control of the total amounts of service supplied by the company;
  - b. In the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, etc.)

Among these criteria Bonbright suggested<sup>31</sup> that three may be considered as primary: (i) the revenue requirement or financial need objective, which takes the form of a fair return standard with respect to private utility companies; (ii) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting the total revenue requirement must be apportioned fairly among the beneficiaries of the service; and (iii)

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<sup>30</sup> J.C. Bonbright, *Principles of Public Utility Rates*, page 291.

<sup>31</sup> *Ibid*, page 292

the optimum-use or consumer-rationing objective, under which the rates are designed to discourage wasteful uses of public utility services while promoting all of the use that is economically justified in view of the relationships between costs incurred and benefits received.

Subsequent authors<sup>32</sup> on the regulation of public utilities frequently reference Bonbright's work and produce lists of ratemaking criteria that are similar. Indeed, Manitoba Hydro's rate making goals, as set out in the current Application<sup>33</sup> consist of the following which are fairly similar:

1. Recovery of Revenue Requirement
2. Fairness and Equity
3. Rate Stability and Gradualism
4. Efficiency
5. Competitiveness of Rates
6. Simplicity.

### 3.2 Cost of Service Principles

In theory no two customers are exactly the same. However, for practical purposes, customers who have similar characteristics in terms of their electricity use (e.g. load profile<sup>34</sup>) and service requirements (e.g., types of facilities used and level of service reliability provided by the utility) are grouped into rate classes and then rates (or rate schedules) are set for each rate/customer class.

As a result, rate making itself consists of two steps. The first is establishing the portion of the total revenue requirement to be recovered from each rate class while the second step involves establishing the rate schedule(s) for each customer class that will return the class' share of the revenue requirement.

The purpose of a cost of service study is linked to the first of these two steps and involves assigning/allocating the pre-established total revenue requirement amongst the

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<sup>32</sup> For example, Charles F. Philips Jr., *The Regulation of Public Utilities*, page 410

<sup>33</sup> Submission, page 7

<sup>34</sup> Load profile refers to the distribution of a customer's electricity use over the 8,760 hours of the year.

utility's customer classes. The primary objective of a cost of service study is the fair allocation or apportionment of costs among the customer classes.

Just as the "cost of providing service" concept underlies the determination of what is a fair and reasonable revenue requirement overall, there is general consensus that a fair assignment of costs to customer classes is achieved when each customer class is assigned the cost incurred to serve it. This has led the principle of "cost causation" as being the primary driver or principle when establishing cost of service methodologies.

The starting point when applying the principle of "cost causation" is that customers should pay for the facilities and services they use and benefit from. However, complexities arise in that:

- A significant portion of Manitoba Hydro's facilities serve more than one customer class and/or provide multiple services. This complicates the cost of service methodology which must now apportion the costs of the facility between services and/or customer classes. While "cost causation" can be used as guiding principle in doing so, there is inevitably going to be some judgement involved.
- While customers not using an asset are generally not viewed as being responsible for its costs, not all customers using a utility's service or facility necessarily impose the same costs on the utility. From a cost causation perspective, what is important is that customers be assigned those costs that their service requirements led the utility to incur. A related issue is the fact that Manitoba Hydro does not have the same service obligation to all customers that use a particular service or facility. For example, not all customers (e.g., SEP customers and those with curtailable rates versus other domestic customer classes<sup>35</sup>) have the same level of service reliability. To the extent the service quality differs customers are not equal and should not bear the same cost responsibility.
- Utility assets typically have long lives and with changes over time in technology, utility economics, the regulatory environment and government policy, the original intent or driver behind an investment may differ from how the investment is currently used to support the utility's operation and serve customers. While it is useful to

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<sup>35</sup> Coalition/MH I-22 g) and May Workshop, page 215

consider the original intent of an investment, generally more weight should be given to the current role of investments in meeting customers' service requirements if cost of service studies are to be supportive of rates that signal to customers the costs of continuing to use the utility's services and, thereby, support the efficiency objective.

- The use of a utility's facilities and the benefits they provide will vary with system conditions. This is particularly true in a hydro-based system where variations in water flows can lead to significant variations in how the system is operated. For example, under median water flow conditions purchased power is likely to be used primarily to support/facilitate exports whereas under low water flow conditions significant reliance may be made on purchases to support domestic load<sup>36</sup>.

Given that the planning underlying Manitoba Hydro's system considers the full range of likely operating conditions, it is appropriate for considerations of "cost causality" to look at the benefits provided by an investment or service activity under the full range of likely operating conditions and not just the operating conditions underpinning the revenue requirement to be used in determining the rates.

While cost causation is generally the primary consideration in establishing cost of service methodologies, it is not the only consideration that must be taken into account. As noted previously, the cost of service study is part of the overall rate making process and, to the extent its results define the costs to be recovered from each rate class, the study and its underlying methodologies will establish the overall rate level and rate increase for each customer class. With this in mind the other rate making objectives related to stability and efficiency cannot be ignored and also come into play.

If rates are to be stable, then the cost of service methodology should not lead to unnecessary year to year volatility in the revenues to be recovered from each customer class. This would suggest preference should be given to cost of service methodologies that track trends in changes in system use and requirements over time as opposed to those that overly focus on use and requirements in a specific year.

Similarly, cost of service methodologies that incorporate marginal costs in establishing cost responsibility and/or developing allocation factors are more likely to produce results

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<sup>36</sup> Appendix 5, page 23. See also 2005 COSS Review, PUB/MH II-9 a)

that are compatible with the efficiency objective of ratemaking as are methodologies that consider cost causality based on current requirements and system operations as compared to ones that focus on the original intent or purpose of an investment.

Issues of practicality such as feasibility of application, understandability and public acceptance can also come into play when establishing a cost of service methodology. The cost of service methodology should be relatively easy to execute. The more complex a methodology is the more expensive it generally is to execute and the more difficult it often is to understand. As a result, there are trade-offs to be made between the perceived benefits (e.g., in terms of accuracy) and the costs involved (in terms of both dollars/time and public acceptability/understanding). Also, public acceptability and understanding requires that the methodologies used should be free from controversy in terms of the data used and how they are applied.

### 3.3 General Approach

Cost of service studies generally employ a three-step process of cost analysis:

- 1) Functionalization: In some cases assets and/or services are used by only one customer class and can be directly assigned to that class. But the majority of a utility's assets and activities support a number of customer classes and the first step is to functionalize the assets and annual expenses (including the cost of capital) according to the services (or functions) the utility provides such as production, transmission, distribution and customer service.

However, these functions are frequently broken down further to capture specific activities either used by different customers or having different cost drivers. It should be noted that functionalization applies not only to a utility's "costs" but also to the other revenues included in the revenue requirement which serve to reduce the costs that need to be recovered through rates.

- 2) Classification: Each function's costs are then classified according to the system design or operating characteristics that caused those costs to be incurred. In the case of electric utilities, costs are generally classified as one of three types: demand costs incurred to meet a customer's maximum instantaneous power

requirements (i.e., demand or capacity); energy costs incurred to provide customers with electricity over a period of time; and, customer costs incurred to carry customers on the system.

- 3) Allocation: Finally each functionalized and classified cost component is allocated to specific customer classes based on each class' contribution to the specific cost driver selected.

### 3.4 Use of Results

The ratio of the revenues that are to be collected from each customer class (assuming no rate rebalancing) to the costs allocated to each class as per the cost of service study is typically used in determining whether current rates are “fair” rates and reasonably reflect the costs to serve each customer class.

This ratio is called the revenue to cost ratio (R/C ratio). An R/C ratio that is close to 1.00 (or 100%) is considered to mean that the customer class is paying its fair share of costs. If the ratio exceeds 1.0 by a large enough margin, the class may be considered to be paying more than its fair share of costs. Alternatively, if the revenue to cost ratio for a customer class is significantly below 1.0, it may indicate that the costs imposed on the system by the class are not being recovered fairly from that class.

Cost of service methodologies inevitably require judgments in the selection of cost drivers and the methods that will be used to allocate costs. They often also involve the use of sample data to estimate the load characteristics of individual customer classes. As a result, cost of service studies are not viewed as precise analysis and, consequently, revenue to cost ratio ranges are usually established in order to determine whether a customer class is paying its fair share of costs. These ranges are referred to as zones of reasonableness (“ZOR”) and will vary by regulatory jurisdiction<sup>37</sup>. In the case of Manitoba Hydro the currently approved ZOR is 95% - 105%<sup>38</sup>.

A Cost of Service Study can also provide useful benchmarks that can inform the rate design for each customer class. By grouping the costs allocated to a customer class by

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<sup>37</sup> The most typical ranges used are 90%-110% and 95%-105%. However, there are utilities that use wider ranges and others that target 100%.

<sup>38</sup> Order 17/06, page 56

cost driver (energy, demand and customer) it is possible to determine the unit costs associated with each cost driver (e.g. customer costs per customer) which can then be used to inform the determination of individual elements of the customer class' rate structure (e.g. customer charge, energy charge and demand charge – where applicable).

Finally, a Cost of Service Study's results can be used to verify the need to maintain the existing distinction between customer classes and/or test the appropriateness of introducing a new customer class. If two existing customer classes have similar unit costs then from a "cost causality perspective" the customers in the two classes are similar and consideration should be given to merging the two classes into one.

Conversely, a cost of service study can be used to determine the merits of separating an existing customer class into two distinct classes. Again, if the resulting unit cost and revenue to cost ratios are the same for both of the "new" customer classes then it would be reasonable to conclude there is no "cost basis" for changing the current customer class definition and creating additional customer classes. However if the results vary then from a "cost causality perspective" there is a difference and consideration should be given to creating new customer classes.

## **4. MANITOBA HYDRO'S PROPOSED COST OF SERVICE METHODOLOGY**

### **4.1 Overview**

Manitoba Hydro's proposed Cost of Service methodology follows the standard three step process of functionalization, classification and allocation. It also continues to use the same broad functional definitions (i.e., Generation, Transmission, Ancillary Services<sup>39</sup>, Sub-Transmission, Distribution (Plant) and Distribution (or Customer) Service as did the methodology approved by the PUB in Orders 117/06 and 116/08.

However, the proposals do include changes in the specific assets to be included in each function, the sub-functionalization and subsequent classification of the assets assigned to each of these broadly defined functions, and the specific allocation factors used to allocate the costs to customer classes.

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<sup>39</sup> While Manitoba Hydro treats Ancillary Services as a separate function the associated costs are subsequently classified and allocated the same as Tariffable Transmission costs.



One of the unique aspects<sup>40</sup> of Manitoba Hydro's currently approved Cost of Service methodology is the formal inclusion of an Export Class which is allocated costs for the purposes of determining Net Export revenues which, in turn are allocated to the domestic customer classes. Manitoba Hydro's proposed Cost of Service methodology retains the concept of an Export Class but includes changes to how the Export Class is defined, the costs that are to be directly assigned to exports as well as the manner in which costs are to be allocated to the export class.

## 4.2 Export Class

During the 1980's and 1990's Manitoba Hydro's approach was to allocate net export revenues to domestic classes based on their share of Generation and Transmission costs<sup>41</sup>. At the time most export sales were opportunity sales at prices considerably less than average costs and also considerably less than the rates paid by domestic customers. Exports at the time were treated as a by-product of the bulk power system and "net export revenues" were determined by netting the variable cost of exports from export revenues. However, it is worth noting that as early as the 1980's the PUB expressed concern about whether additional costs should be allocated to exports should firm exports materialize<sup>42</sup>.

Current discussions<sup>43</sup> regarding the inclusion of an "export class" in the COSS methodology date back to Manitoba Hydro's Status Update filing in 2002 where the Corporation proposed changes to the allocation of net export revenues<sup>44</sup>. In particular, Manitoba Hydro proposed to allocate net export revenues to all grid-connected domestic customer classes based on their total allocated costs (as opposed to just based on the generation and transmission costs that had been allocated to each customer class).

The rationale for the change was that export revenues had grown (both in absolute terms and on a \$/kWh basis) to the point where allocating the net export revenue strictly

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<sup>40</sup> Most utilities do not recognize "exports" as a separate customer class in their cost of service studies.

<sup>41</sup> 2005 COSS Review, RCM/TREE/MH I-11 a)

<sup>42</sup> 2005 COSS Review, RCM/TREE/MH I-11 a), page 2

<sup>43</sup> There were earlier discussions in the late 1980's. However, these did not lead to the inclusion of an export class in the COSS.

<sup>44</sup> Status Update Filing, Appendix 12, pages 28-29

on the basis of Generation and Transmission costs was distorting the cost of service study results and the resulting rates charged to customers<sup>45</sup>. This proposed change meant that the results of the COSS methodology would vary depending upon what costs were “attributed” to exports in the calculation of net export revenues<sup>46</sup>.

This, in turn, drew attention to the issue of whether or not exports were attracting an appropriate share of costs. In its decision, the PUB expressed the view<sup>47</sup> that “many direct and indirect costs related to export power sales are currently not included in Hydro’s calculation of net export revenues”. While the PUB confirmed the existing approach to allocating net export revenues, the Board directed<sup>48</sup> Manitoba Hydro to prepare cost of service studies that reflected: a) the creation of a Firm Export Class and b) the creation of an Opportunity Export class. The PUB indicated that after this information was filed the allocation methodologies may require further consideration.

In its 2005 COSS Submission Manitoba Hydro’s proposal called for two export classes: Firm Exports and Opportunity Exports. Firm exports would represent those made based on dependable water flows over and above what was required to meet forecast domestic requirements while Opportunity exports would be those based on the availability of generation in excess of dependable supply<sup>49</sup>. Opportunity exports would attract variable costs similar to those assigned under the then existing methodology whereas Firm Exports would attract a full share of the remaining embedded Generation and Transmission costs in the same manner as domestic customers<sup>50</sup>.

In its Decision the PUB rejected this approach and directed<sup>51</sup> that there be one Export class which would be directly allocated the costs of purchases (including wind), thermal fuel and a portion of thermal generation fixed costs. The balance of the generation

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<sup>45</sup> Manitoba Hydro’s 2002 Rebuttal Evidence, pages 18-20

<sup>46</sup> At the time Net Export Revenues were allocated to customer classes based on each classes’ share of Generation and Transmission costs. The result was that the question of what costs to allocate to Exports was somewhat moot as any change in the allocation of such cost to Exports would simultaneously change both the total Generation and Transmission costs allocated to customer classes and the value of Net Export Revenues and the effects would be largely offsetting.

<sup>47</sup> Board Order 7/03, page 97

<sup>48</sup> Board Order 7/03, page 98

<sup>49</sup> 2005 COSS Review, PUB/MH I-14 a)

<sup>50</sup> PUB-MFR 13

<sup>51</sup> Order 117/06, page 76

costs would be allocated to the remaining unserved export load and domestic customers on a similar basis.

#### 4.2.1 Manitoba Hydro's Proposed COSS Treatment

In its current proposal Manitoba Hydro again calls for the inclusion of two export classes in its COSS methodology reflecting dependable (i.e. firm) versus opportunity sales, where firm sales are assigned full embedded cost responsibility while opportunity exports are only assigned incremental costs<sup>52</sup>. This approach is supported by CA Energy Consulting<sup>53</sup>, the consultants retained by Manitoba Hydro to review its cost allocation methods<sup>54</sup>.

To determine the split between the dependable export class and the opportunity export class, Manitoba Hydro compares the forecast dependable energy over and above domestic requirements (five year average) to the total energy available in excess of domestic requirements under average water flows.

The five years used are those immediately after the test year which are typically years 3 to 8 of the IFF<sup>55</sup>. Based on IFF12, which is the financial forecast used in the Submission to illustrate the impacts of the COSS proposals, this results in a split where approximately 50% of export volumes are considered Dependable and 50% are considered Opportunity sales<sup>56</sup>.

#### 4.2.2 ECS Comments

##### *Need for Export Class/Classes<sup>57</sup>*

As noted in Section 3.0, the purpose of performing a Cost of Service Study is to provide information that will assist in both setting the rate levels and establishing the rate design for the various customer classes served by a utility so as to permit a fair recovery of a utility's embedded cost based revenue requirement. Overall, cost of service study

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<sup>52</sup> Submission, page 4

<sup>53</sup> Appendix 5, page 8

<sup>54</sup> PUB-MFR 14

<sup>55</sup> Submission, page 16

<sup>56</sup> COALITION/MH I-21 a)-c)

<sup>57</sup> The comments included in this section draw on those made by Mr. Harper in his March 2006 Evidence filed in the 2005 COSS Review proceeding.

results are frequently used to establish whether a particular customer class is paying its fair share or whether its rates are being cross-subsidized by customers in other rate classes.

However, in the case of “exports”, rates are not set on a cost of service basis. Rather they are established by competitive forces and, more recently, formal market mechanisms. They are fundamentally different from domestic sales. With domestic sales, utilities have an obligation to connect<sup>58</sup> and an ongoing obligation to serve. Utilities are required to ensure they have sufficient transmission and generation facilities in place to reliably meet their forecasted obligations. The timing of new facilities and the incurrence of the associated costs are driven by these forecast requirements.

In contrast, a utility’s decision to commit to an export sale will be guided by the economics and is usually time limited. The types of considerations that go into such a decision tend to focus on the incremental revenues, costs and risks associated with the proposed transaction. One key illustration of the difference between domestic and export sales is that a utility can be required to install additional facilities to meet growing domestic requirements even if incremental revenues do not cover the incremental costs. However, a utility would not generally commit to increased export sales under the same circumstances.

As a result, a cost of service study, derived from the utility’s annual revenue requirement, does not provide the type of information needed to determine whether the rates associated with a particular defined class of export sales are recovering their associated costs.

Indeed, there is a real danger that the results of a cost of service study that includes an “export class” (or classes) could be misinterpreted and used to draw inappropriate conclusions regarding the desirability and profitability of export sales. This concern was acknowledged<sup>59</sup> by NERA in their report on Classification and Allocation Methods for

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<sup>58</sup> Regulated utilities are typically required to respond to requests for connection and make an offer to connect, subject to established/regulator approved capital contribution policies.

<sup>59</sup> Appendix 11.2, pages 31-32

Generation and Transmission in Cost-of-Service Studies prepared for Manitoba Hydro. It was also noted by CA Consulting in its 2012 Report to Manitoba Hydro<sup>60</sup>.

In Order 154/03<sup>61</sup>, the Board varied its original 2003 Decision to permit Manitoba Hydro to further review the issue of the creation of an export class or classes and to further explore options for the allocation of net export revenues. In this same decision, the MPUB clarified<sup>62</sup> that the purpose of its requests in Order 7/03 for the inclusion of firm and opportunity export classes was not to establish a new rate class but rather to examine alternate approaches by which export power costs and revenues may be determined and ultimately to assist in ratemaking that is fair and equitable for domestic customers.

Thus the purpose in creating an export class (or classes) is to permit the COSS methodology to more formally consider the costs that should be associated with exports in the determination of net export revenue. It is unlikely that the fundamental differences (and nuances) between export and domestic sales both in terms of the commitment to serve and how they influenced utility planning and costs, can all be adequately captured by the COSS methodology. However, it's important to remember that the end objective is not to define the costs for exports for purposes of setting export prices. Rather, the objective is to arrive at a fair allocation of export revenues to the domestic customer classes.

Whether an Export class (or classes) is (are) required will depend on a couple of considerations:

- Significance – There are two dimensions regarding significance. One is the significance of export revenues in the overall operation and revenue requirement determination of the utility and, hence, their potential effect on the COSS results. If export revenues are minor relative to domestic revenues then net export revenues (even when calculated considering only incremental costs) are unlikely to have a material impact on the COSS results. Furthermore, if export revenues are small

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<sup>60</sup> Appendix 5, pages 6-7

<sup>61</sup> Board Order 154/03, pages (vi) and (vii)

<sup>62</sup> Board Order 154/03, page 32

then it is unlikely that considerations other than those involving short run incremental costs were involved in determining export volumes and an export class is not required for COSS purposes.

The second is the level of export prices relative to domestic prices and effect that increases in domestic load/reductions in export sales have on the overall level of costs to be recovered from domestic customers. In situations where domestic prices are less than export prices increased usage by one customer class will result in increased costs to all customers. Furthermore, the determination of the costs to be attributed to exports and the subsequent allocation of net export revenues are key factors in determining the relative cost/rate increases that will be experienced by the different customer classes<sup>63</sup>.

- Impact on Investment Decisions – Another consideration is whether export sales (or the potential for increased export sales) have an impact on the investment decisions that the utility makes, either in terms of the nature of the facilities built or the timing of the in-service dates such that investment-related costs could be attributed to exports in the determination of net export revenues. If the view is that the COSS should attribute a portion of the revenue requirement's "fixed cost" attributable to investment in facilities then this is best facilitated by including an export class that can then be allocated, along with the domestic classes, a portion of these costs.

In Manitoba Hydro's case, export revenues do represent a significant portion of total revenues. At the time of the 2005 COSS review, when the PUB confirmed the introduction of an Export class, export revenues represented just under 35% of the total financial forecast revenue for 2005/06 used in PCOSS06<sup>64</sup>. This value has declined to roughly 20% for the 2013/14 year from IFF12 (adjusted for Board Order 43/13) used in the current submission<sup>65</sup>. However, it is noted that this percentage is forecast to increase to roughly 30% by 2020/21 when Keeyask is in-service<sup>66</sup>.

Furthermore, at the time of the 2005 COSS review average export revenue exceeded average domestic revenues and in the case of transmission voltage customers the

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<sup>63</sup> Further explanation and examples regarding this issue can be found in PUB/MH I-26 from the 2005 COSS Review.

<sup>64</sup> 2005 COSS Review, PCOSS06, Schedule C14

<sup>65</sup> Appendix 3.1, page 44

<sup>66</sup> Filing for Interim Electric Rates Effective April 1, 2016, Attachment 1, page 41.

difference was almost 100%. This led to concerns that increases in load by one customer class could lead to counter-intuitive results for the Cost of Service Study due to the definition and allocation of net export revenues<sup>67</sup>.

As can be seen from the following table, the relationship between average export revenues and average domestic revenues as forecast in IFF12 for 2013/14 has changed such that average domestic revenues exceed average export revenues and average revenues from domestic transmission customers are roughly equivalent to average export revenues<sup>68</sup>.

<b>TABLE #1 – AVERAGE REVENUES (\$/MWh)</b>		
	PCOSS06 <sup>1</sup>	PCOSS14-Amended <sup>2</sup>
Average Export Revenue	\$55.9	\$34.9
Average Domestic Revenue	\$43.9	\$54.7
Average GS>100 Revenue	\$28.1	\$35.7
Sources: 1) PCOSS06 – Energy from Schedule D5 (@Generation). Revenues from Schedule C13 (Unadjusted Revenue)		
2) PCOSS14-Amended – Energy volumes from Schedules D1, D2 and D5 (@Generation). Revenues from Schedule C13 (Unadjusted Revenue)		

However, it is anticipated that the average 2013/14 forecast revenue from firm exports exceeded those for domestic transmission customers<sup>69</sup>. Furthermore, forecasts of future average domestic and export revenues filed in Manitoba Hydro's recent Interim April 2016 Rate Application<sup>70</sup> indicate that average export revenues are expected to increase faster than average domestic revenues over the next decade.

<sup>67</sup> As outlined earlier, not only would an increase in load for transmission customer increase the costs to be recovered from all customer classes but the increase could also disproportionately fall on the other customer classes. See 2005 COSS Review, PUB/MH I-26

<sup>68</sup> Appendix 3, Schedules B1 and B2.

<sup>69</sup> Forecast average revenues are not broken down by Manitoba Hydro as between firm and opportunity. However, actual average 2013/14 revenues from firm sales were almost twice that from opportunity sales (2015/16 & 2016/17 GRA, Appendix 11.19).

<sup>70</sup> Attachment 16

As a result, while the significance of export revenues and comparative export average revenues may not currently be as great as it was at the time of the 2005 COSS review issues still exist and are expected to increase in the future.

With respect to the second consideration, exports do impact on the investment decisions that Manitoba Hydro makes:

- Firm exports contracts are included in the demand forecasts used in Manitoba Hydro's Power Resource Plans<sup>71</sup> and impact the future need dates generation resources<sup>72</sup>.
- Firm exports contracts require firm transmission service the requirements for which are included in Manitoba Hydro's transmission planning<sup>73</sup>.
- The possibility of increased Export sales (dependable more so than opportunity<sup>74</sup>) can drive decisions to advance new generation in-service dates ahead of what is needed for Manitoba load<sup>75</sup>. Evidence of this can be found in the recent decisions to pursue both Wuskwatim and Keeyask in advance of the need date for new resources to serve Manitoba load<sup>76</sup>.

**Overall, Manitoba Hydro's proposal to continue to include exports as a customer class (or classes) in its Cost of Service Methodology is reasonable.**

#### *Need for Two Export Classes - Firm and Opportunity Exports*

A customer class represents a group of customers who receive roughly the same "service" and have roughly the same service requirements in terms of the facilities and activities required to serve them.

Manitoba Hydro exports power under a variety of long term export contract arrangements including System Participation (formerly System Power) Sales and

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<sup>71</sup> 2016/17 Supplemental Filing, Attachment 17

<sup>72</sup> May Workshop, page 309

<sup>73</sup> May Workshop, page 432

<sup>74</sup> May Workshop, pages 263-265 and Coalition/MH I-25 a) & b)

<sup>75</sup> PUB/MH I-2 b) and 2005 COSS Review, MIPUG/MH II-1 a)-b)

<sup>76</sup> PUB/MH I-11 a) – b) and 67 a). With regard to the actual NFAT decision, the most recent 2014 PUB Report regarding Keeyask found (page 20) – "there are compelling economic, financial and commercial reasons to advance the Keeyask project to 2019". Similarly, in its 2004 Report regarding Wuskwatim the CEC found (page 67) noted that "there is no need for the Projects to be constructed with an in-service date of 2010 when domestic demand for energy is considered alone".



Seasonal Diversity. Furthermore, within each of these broad categories the terms of the individual contracts will vary in terms of i) the period of time over which Manitoba Hydro will provide capacity and energy (e.g. 5x16 hours versus 7x16 hours) and ii) the extent to which its obligations can be reduced under adverse water conditions<sup>77</sup>.

However in all cases Manitoba Hydro has no obligation to serve firm contracts after the term of the contract has expired and does not carry any capacity planning reserve margin for exports (as it does for firm Manitoba load). In addition, there are curtailment provisions that can be activated under circumstances when continuing to export would result in the interruption of Manitoba firm load<sup>78</sup>.

Thus while Manitoba Hydro is obligated to include in its resource plan capacity and energy resources to serve these types of long term export contracts (i.e. the energy sold is dependable energy), the service provided is less reliable than that provided to Manitoba firm load.

As well as exporting power under these long term contracts, Manitoba Hydro also exports power under shorter term arrangements including both short-term contracts (less than one year) and sales on both a day ahead and real time basis in US as well as Canadian markets when profitable using available capacity and energy<sup>79</sup>. These opportunity sales are made from energy that is surplus to dependable energy.

The overall result is that the firmness and reliability associated with, and thus the costs imposed on the Manitoba Hydro system can vary significantly depending upon the type of export. Furthermore, the nature of these service requirements indicates that to treat all exports similar to Manitoba firm load would clearly overstate the service requirements and costs incurred for exports. On the other hand, to view all exports sales as only responsible for short-term variable costs would understate the impact that exports (particularly firm/dependable exports) have on Manitoba Hydro's investment planning.

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<sup>77</sup> Coalition/MH I-22 b)

<sup>78</sup> Coalition/MH I-22 a)

<sup>79</sup> Coalition/MH I-22 a) and 2005 COSS Review, PUB/MH I-12 b) & CAC/MSOS/MH II-3 c)

This means that adopting one export class for purposes of the COSS (as directed by the PUB in Order 117/06) would require a decision as the relative responsibility that this class should bear for embedded costs relative to the cost responsibility of Manitoba firm load. However, given the range of export arrangements and the fact that decisions regarding investment timing and sequence are based on economic analysis and forecast costs (and not the embedded accounting costs used to establish rates) this means that determining the appropriate cost responsibility factor would likely be impractical and, at best, arbitrary.

**Manitoba Hydro's proposal to establish two export classes where one is for firm export sales sourced from dependable energy which would attract embedded costs in the same a manner as Manitoba firm load and the second is based on opportunity sales sourced from surplus energy which would attract only variable costs is a reasonable and workable alternative.**

It recognizes that i) there is a critical difference in the reliability associated with export sales sourced from dependable energy and ii) such sales have a different role in Manitoba Hydro's generation and transmission planning processes. It also results in an allocation of costs to exports overall that is greater than just variable costs but less than the costs allocated to Manitoba firm load and in doing so acknowledges that exports have an impact on Manitoba Hydro's investment decisions but at the same time results in less costs being allocated thereby recognizing the lower level of reliability associated with export sales.

The approach is not perfect but it is far superior to adopting only one export class or having no export class at all. In this regard it is important to recall the original purpose for introducing an export class (or classes) which is not to determine the cost of exports for purposes of setting export rates but rather to attribute a reasonable quantum of costs to exports for purposes of determining net export revenues which will then be allocated to Manitoba Hydro's domestic customer classes.

#### *Distinguishing Between Firm and Opportunity Exports*

Manitoba Hydro does not define firm exports for the test year in the COSS based on the firm export contracts forecast to be in place but rather on the dependable energy

forecast to be available in the year once the requirements of Manitoba firm load have been accounted for. This approach is superior to one based on contracts expected to be in place as:

- Manitoba Hydro can be expected to continue to pursue additional firm export contracts for the test year based on forecasts of available dependable energy<sup>80</sup> and
- It avoids debate regarding the treatment of specific types of contracts such as the hybrid contracts flagged by CA Consulting in its August 2015 report<sup>81</sup>.

**The use of the five year average forecasted split between dependable energy surplus to domestic needs and the average energy available in excess of dependable energy for years 3 to 8 of the financial forecast is also reasonable as each year used captures the full range of possible water flows and the use of an average will serve to stabilize the COSS results from one year to the next.**

### 4.3 Revenues and Costs Used for COSS Methodology Review

#### 4.3.1 Manitoba Hydro's PCOSS14-Amended

To depict the impact of its proposed Cost of Service methodology Manitoba Hydro has provided a Prospective Cost of Service Study (PCOSS14-Amended)<sup>82</sup>. This Cost of Service Study uses the costs and revenues for 2013/14 as forecast in IFF12 as inputs to Manitoba Hydro's Cost of Service Model which is based on its proposed methodology.

#### *Revenue and Cost Adjustments*

Various adjustments are made to the revenues and costs as set out in IFF12 prior to applying the proposed COSS methodology. These are set out in MIPUG-MFR 2 with the more significant ones being:

- The adjustment of General Consumer (i.e. Domestic Customer) revenues to account for i) the impact of Order 43/13 (regarding the overall 2013/14 approved rate increase) versus the revenues as forecast in IFF12; ii) the removal of revenues to be

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<sup>80</sup> May Workshop, page 314

<sup>81</sup> Appendix 2, page 6 and Appendix 1, page 3

<sup>82</sup> Appendix 3

accrued to the Bipole III deferral account; and iii) the addition of the revenues lost through the implementation of uniform rates as a result of Bill 27 (with an accompanying increase in net income).

- The re-assignment of the Non-Energy revenue reported in IFF12 as an offset to Operating and Administrative costs.
- Adding back the amortization of diesel contributions to Depreciation (with an accompanying decrease in net income) and, similarly, adding back the 3<sup>rd</sup> party diesel contributions to Rate Base.

Then, for purposes of the Cost of Service Study, the costs are grouped into three categories: i) Operating (which includes adjusted O&A Expense per the IFF, Water Rentals & Assessments and Fuel & Power Purchases); ii) Interest (which includes Finance Expense, Capital Taxes, Net Income and Non-Controlling Interest) and iii) Depreciation.

#### *Cost Functionalization – Operating Costs and Depreciation*

The assignment of these costs to functions is facilitated by Manitoba Hydro's financial reporting systems which track Operating Costs and Depreciation via settlement cost centres ("SCC")<sup>83</sup>. The SCCs generally align with the functional definitions used by the proposed COSS methodology and, where they do not, sufficient detail is generally available through the financial systems that the costs can be reassigned as between COSS functions<sup>84</sup>.

The notable<sup>85</sup> exception to this is that Manitoba Hydro's financial reporting systems include a separate settlement cost centre for the Operating and Depreciation costs associated with the Communications and Control Systems which cannot be directly assigned to Manitoba Hydro's COSS functions. As a result, the operating and depreciation costs attributed to the Communications and Control Systems SCC are functionalized for purposes of the COSS as follows:

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<sup>83</sup> Appendix 3.1, page 27

<sup>84</sup> See Appendix 3, Schedules C6-Amended and C12-Amended. See also Coalition/MH I-26 a) & 27 a)- c);

<sup>85</sup> Notable in that it is evident from the COSS schedules.

- The costs of communication provided for system control purposes including communications, instrumentation, monitoring and SCADA are functionalized 36/28/36% to Generation, Transmission and Sub-transmission<sup>86</sup>.
- The balance of the operating and depreciation costs associated with communications are assigned to the four functions (Generation, Transmission, Sub-transmission and Distribution Plant) in proportion to functionalized operating costs, excluding Water Rentals, Fuel, Power Purchases, Distribution Services and directly assigned A&RL & Diesel costs<sup>87</sup>.

#### *Cost Functionalization – Rate Base and Interest Costs*

Interest Costs are allocated to functions using rate base (i.e., the assets) associated with each function. Again, Manitoba Hydro's financial reporting systems track its Plant In-Service and Regulatory Assets by Asset Classes that generally align with the COSS functions and again, where they do not, sufficient detail is generally available that costs can be reassigned to the appropriate function<sup>88</sup>.

In this instance there are three asset classes - Buildings, Communications and General Equipment<sup>89</sup> – that do not readily align with Manitoba Hydro's COSS functions:

- For General Equipment, the value of the assets is allocated to functions (excluding Diesel) in proportion to functionalized Operating costs excluding Water Rentals, Fuel, Power Purchases and directly assigned Diesel operating costs<sup>90</sup>.
- For Communications, the rate base associated with system control (including communications, instrumentation, monitoring and SCADA) was functionalized to Generation, Transmission and Sub-transmission using the same "split" as for Operating costs. The portion functionalized as Transmission is all attributed to Ancillary Services. The balance of the Communications rate base is also

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<sup>86</sup> PUB/MH I-45 a) – d)

<sup>87</sup> While the response to PUB/MH I-47 suggests that water rental and power purchases are included in the allocation base, during the May Workshop (pages 863-864) Manitoba Hydro confirmed they were excluded.

<sup>88</sup> See Appendix 3, Schedules C8-Amended and C10-Amended. See also Coalition/MH 34 b)

<sup>89</sup> These asset classes also include certain Regulatory Assets. See Coalition/MH I-14 a) – d)

<sup>90</sup> Coalition/MH I-35 a)

functionalized in the same manner as the Operating and Depreciation costs associated with Communications<sup>91</sup>.

- For Buildings, the rate base associated Diesel is directly assigned and the balance is functionalized in the same manner as General Equipment<sup>92</sup>.

### *Revenues*

The revenues reported in the IFF include not only General Consumer and Export revenues but also Other Revenues. A portion of these revenues can be assigned directly to a specific function based on the nature/source of the revenues. However over 60% of the revenues are assigned to all functions in proportion to labour charges based on the initial functionalization of costs as done in Manitoba Hydro's financial systems<sup>93</sup>.

Finally, the General Consumer (domestic class) revenues as reported in the IFF include not only revenues associated with the rates approved for each class for electricity use (which are subject to PUB approval) but also \$5.78 M in revenues from other charges such as Late Payment charges, inspection fees, disconnect/reconnect fees, federal meter disputes and special read fees<sup>94</sup>. For purposes of the COSS allocation, these revenues are pro-rated to all customer classes except Street Lighting, GSL (>30 kV) and SEP (>30 kV) based on "Allowable Revenue per Board Order 43/13"<sup>95</sup>.

### **4.3.2 ECS Comments**

#### *Operating and Depreciation Costs*

**With respect to the allocation of the Operating and Depreciation costs associated with Communications and Control Systems, the overall approach whereby communications for system control are functionalized separately and the balance**

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<sup>91</sup> The functionalization can be seen in the Average Rate Base Finance and Reserve Tab of the PCOSS14-Amended Model

<sup>92</sup> The functionalization can be seen in the Average Rate Base Finance and Reserve Tab of the PCOSS14-Amended Model

<sup>93</sup> Coalition/MH I-2 b) – e)

<sup>94</sup> Coalition/MH I-4 a) – b)

<sup>95</sup> This allocation can be seen in the Revenue for PCOSS14 file provided in conjunction with the PCOSS14-Amended model. See also Coalition/MH I-4 c) & d)

**of the costs are functionalized based on operating costs as a proxy for labour appears reasonable.** The only issues are:

- The basis for determining the allocation factors for system control costs was established in 1997. Manitoba Hydro claims that any updates would be expected to have a negligible impact on the RCC given the dollars involved. This is likely the case. **However, at the same time, given both the investment that has taken place and changes in the assignment of assets to functions since 1997, the factors used to functionalize system control costs (36/28/36%) could have changed materially since then and should be reassessed.**
- The functionalization is done “outside” the COSS model and does not change when assets and their associated operating costs are re-functionalized as part of the COSS model. This can be seen by comparing Schedules C6 and C12 from PCOSS14 and PCOSS14-Amended. The functionalization of the Depreciation and Operating costs for Communications and Control Systems is the same in both cases even though the functionalization of Dorsey’s operating costs was changed. This was also confirmed during the May Workshop<sup>96</sup>. **Ideally, the Depreciation and Operating costs associated with Communications should be functionalized as part of the COSS model.** This would enable the model to reflect any changes in the initial functionalization of asset/activities made via Manitoba Hydro’s financial systems that are made by the COSS model through the application of Manitoba Hydro’s cost of service methodology.

#### *Rate Base and Interest Costs*

In the case of Rate Base for Communications, Buildings and General Equipment, the general approach of using operating costs as a proxy for labour costs as the basis for functionalizing the associated assets is reasonable. In this instance, the functionalization of the Rate Base values is incorporated in the COSS model and therefore can reflect the functionalization of operating costs as established by the COSS.

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<sup>96</sup> Pages 188-189

**However, the functionalization of the Rate Base for Communications does rely on the same 1997 analysis as was used for Operating and Depreciation costs and, therefore, the same issues exist regarding the appropriateness of the 36/28/35% factors used.**

### *Revenues*

With respect to the functionalization of the \$14.6 M in Other Revenues, roughly \$9.2 M is assigned to all functions in proportion to labour charges based on the initial functionalization of costs as done in Manitoba Hydro's financial systems<sup>97</sup>. However, this means that the functionalization of these revenues does not change when assets and their associated operating costs are re-functionalized as part of the COSS model. Ideally, **Other Revenues should be functionalized as part of the COSS model so that it can reflect the Operating and associated labour cost functionalization as established by the "model"**.

With respect to the treatment of the revenues from other sources initially reflected in General Consumer Revenues, it is noted that over 70% of the revenues are associated with Late Payment charges and over the 2012-2015 period more than 80% of the Late Payment charge revenue was from the Residential class<sup>98</sup>. Allocating revenues from Late Payment charges and Customer Adjustments (the "General Consumer Adjustment") on the basis of revenue by class results in just over 51% of the revenue being assigned to Residential whereas Residential likely contributes close to 80% of the revenue. **A more appropriate allocator for the Late Payment Charges and Customer Adjustments revenues would be to pro-rate the revenues based on the historical proportion of Late Payment charge revenues received from each class, given that Late Payment charges represent most of the revenues**

The following table estimates<sup>99</sup> the change in the allocation of these revenues that would result from adopting this approach.

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<sup>97</sup> Coalition/MH I-2 b) – e)

<sup>98</sup> Coalition/MH I-4 a) – e)

<sup>99</sup> Manitoba Hydro has not provided historical Late Payment charge revenues broken down by General Service class. The table allocates the revenues to these classes using the proportion of revenue by class, excluding Street Lights, GSL>30 kV and SEP>30kV similar to Manitoba Hydro's proposal.



<b>Table #2 - Allocation of General Consumer Adjustment</b>			
	<u>PCOSS14- Amended</u>	<u>Proposed Allocation</u>	
Residential			
Residential	\$2,866,864	\$4,535,451	
Seasonal	\$39,973	\$63,238	
Water Heating	\$5,975	\$9,452	
Total	\$2,912,812	\$4,608,142	
General Service - Small			
Non Demand	\$678,306	\$266,691	
Seasonal	\$2,849	\$1,120	
Water Heating	\$2,653	\$1,043	
Total Non Demand	\$683,809	\$268,854	
General Service Small			
Demand	\$696,097	\$273,686	
SEP			
GSM	\$3,922	\$1,542	
GSL			
General Service - Medium	\$958,369	\$376,803	
General Service - Large			
0 - 30 Kv	\$435,967	\$171,410	
30 - 100 Kv			
31 - 100 Kv Curtailable			
Over - 100 Kv			
Over - 100 Kv Curtailable			
Total GSL	\$435,967	\$171,410	
Area & Roadway Lighting			
Street Lighting			
Sentinel Lighting	\$15,592	\$6,130	
TOTAL	\$5,706,567	\$5,706,567	
Note: Allocation between Residential and Other Customer classes based on relative Late Payment Charges 2012-2015			
Allocation among "Other Customer Classes" based on Allowable BP 43/13 Revenue per Manitoba Hydro as Late Payment history not provided			

Incorporating this change into the corrected<sup>100</sup> version of PCOSS14-Amended has a minor impact on the customer class revenue to cost ratios as illustrated in Table #3.

TABLE #3 - RECOMMENDED GENERAL CONSUMER ADJUSTMENT ALLOCATION											
Customer Class	Corrected PCOSS14-Amended					Impact of Alternative General Consumer Adjustment Allocation					
	Total Cost	Class	Net Export	Total	RCC %	Total Cost	Class	Net Export	Total	RCC %	RCC
	(\$000)	Revenue (\$000)	Revenue (\$000)	Revenue (\$000)	Current Rates	(\$000)	Revenue (\$000)	Revenue (\$000)	Revenue (\$000)	Current Rates	Change
Residential	626,705	588,630	38,166	626,795	100.00%	626,705	590,388	38,142	628,530	100.30%	0.30%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,450	134,614	7,836	142,450	107.50%	-0.40%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,349	135,656	8,173	143,829	104.00%	-0.30%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	200,027	186,215	11,908	198,123	99.00%	-0.30%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	99,732	84,692	5,923	90,615	90.90%	-0.20%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,534	57,808	3,716	61,524	100.00%	0.00%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	204,982	189,258	12,260	201,517	98.30%	0.00%
SEP	968	826	-	826	85.40%	968	824	-	824	85.20%	-0.20%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	21,969	21,620	408	22,028	100.30%	0.00%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,486,716	1,401,075	88,366	1,489,440	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	612	7,224	72.60%	0.00%
Export	256,200	345,233	-	256,200	100.00%	256,256	345,233	-	256,256	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,920	1,752,920	-	1,752,920	100.00%	0.00%
*Includes Curtailment Customers											

### PCOSS14-Amended Results

During the interrogatory process Manitoba Hydro noted a number of corrections that were required to the PCOSS14-Amended methodology as originally filed.

These included:

- Corrections to the energy weighting factors used in allocating Generation costs<sup>101</sup>,
- Corrections to the Operating cost base used to assign the costs associated Communications, General Equipment and Buildings to functions<sup>102</sup>, and
- Corrections to the customer counts used to allocate Meter Reading, Meter Maintenance and Meter Assets to customer classes<sup>103</sup>.

The following table sets out the impact of these three corrections on the PCOSS14-Amended results.

<sup>100</sup> See the following discussion regarding the PCOSS14 Amended results.

<sup>101</sup> GAC/MH I-55

<sup>102</sup> Coalition/MH I-35 a)

<sup>103</sup> Coalition/MH I-93 a) – c)

Table #4										
Corrected PCOSS14-Amended Results and Change in RCC%										
		Class	Net Export	Total	RCC %	Cost less		Change Cost less	Change in	Change in
Customer Class	Total Cost (\$000)	Revenue (\$000)	Revenue (\$000)	Revenue (\$000)	Current Rates	NER		NER	RCC	NER
Residential	626,705	588,630	38,166	626,795	100.00%	588,539		- 1,495	0.20%	
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	124,609		161	-0.10%	
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	130,171		319	-0.20%	
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	188,111		159	-0.10%	
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	93,805		157	-0.20%	
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	57,815		10	0.00%	
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	192,715		691	-0.30%	
SEP	968	826	-	826	85.40%	968		- 0	0.00%	
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	21,560		- 17	0.10%	
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,398,295		- 14	0.00%	
Diesel	9,948	6,612	612	7,224	72.60%	9,336		14	-0.20%	
Export	256,200	345,233	- 89,033	256,200	100.00%					- 2,130
Total System	1,752,864	1,752,864	-	1,752,864	100.00%					
*Includes Curtailment Customers										

## 4.4 Directly Assigned Costs

### 4.4.1 Manitoba Hydro Proposal

#### *Domestic Customer Classes*

It is generally accepted that, where feasible, costs should be directly assigned to customer classes. Manitoba Hydro proposed COSS methodology directly assigns the following costs to a specific Domestic Customer class<sup>104</sup>:

- Street Lighting Assets – The interest, depreciation and operating costs (totalling \$15.3 M) associated with street lighting assets<sup>105</sup> are directly assigned to the Area and Roadway Lighting (A&RL) class.
- Diesel Community Generation and Distribution Assets – The interest, depreciation and operating costs associated with the Generation and Distribution facilities in Diesel communities are directly assigned to the Diesel class. (Generation - \$9.4M and Distribution - \$0.6 M). It should be noted that Rate Base associated with Buildings in Diesel Communities is also directly assigned to the Diesel class<sup>106</sup>.
- Surplus Energy Program – The energy-related revenue forecast to be received from SEP customers under market-based SEP prices is directly assigned to the SEP

<sup>104</sup> Appendix 3, Schedule E1-Amended

<sup>105</sup> COW I-1 b)

<sup>106</sup> PCOSS14-Amended, Schedule C8

customers as Generation and Transmission costs. The revenues are pro-rated between Generation/Transmission and between Operating/Depreciation/Interest in proportion to the overall costs in these functions<sup>107</sup>.

- Curtailable Program – The rate discounts applicable to Curtailable Rate Program (“CRP”) are assigned directly to the curtailable GSL 30-100 and GSL>100 customer classes (\$5.8 M). The offsetting amount is treated as a cost of Generation<sup>108</sup>.
- DSM Costs – These costs include both the amortization and interest on the cost of individual DSM programs and support activities that have been “capitalized” as Regulated Assets as well as annual operating costs associated with DSM programming that are not capitalized. The DSM Program costs are assigned directly to the customer classes whose customers are participating. The amortization, interest and operating costs associated with DSM support activities are allocated to the domestic customer classes using the same weighted energy allocator as is used for Generation except with only the Domestic customer classes included<sup>109</sup>.

These proposals mirror the currently approved COS methodology with the exception of the treatment of DSM Costs which Order 116/08 directed be assigned to Exports.

### *Export Classes*

Manitoba Hydro proposal directly assigns the following costs to the Export customer classes<sup>110</sup> for purposes of determining Net Export Revenues:

- Uniform Rate Adjustment (“URA”) Costs (\$23.5 M);
- Affordable Energy Fund (“AEF”) Costs (\$12.8 M); and
- National Energy Board Fees (\$0.96 M).

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<sup>107</sup> Coalition/MH I-20 a) – b)

<sup>108</sup> PCOSS14-Amended, Schedule E1

<sup>109</sup> Coalition/MH I-18 a) – b)

<sup>110</sup> Appendix 3, page 4 and Schedule E1-Amended

#### 4.4.2 ECS Comments

##### *Domestic Customer Classes*

**Manitoba Hydro's direct assignment of costs for those assets and activities related only to Street Lighting is appropriate as is the direct assignment of the energy revenue from SEP customers.**

The direct assignment of depreciation and interest cost to the Diesel class includes the \$1 M increase in depreciation due to the exclusion of the amortization of 3<sup>rd</sup> party contributions and roughly \$635,000<sup>111</sup> additional allocated Interest costs due to the exclusion of 3<sup>rd</sup> party contributions from the Diesel Rate Base, where both changes were attributed to the Diesel Settlement Agreement<sup>112</sup>. During the Workshop Manitoba Hydro indicated that the inclusion of the Diesel class in the Net Export Revenue allocation more than offset these increased costs<sup>113</sup>.

However, since the Net Export revenue allocated to Diesel is only \$626,000<sup>114</sup> it is by no means evident that this is the case. Furthermore, without being able to reference the actual wording of the Agreement it is not clear if the intent was to make the adjustments for 3<sup>rd</sup> party contributions just for purposes of establishing the allocation base for Net Export Revenue or whether the adjustments were also meant to be reflected in the costs directly assigned to the Diesel class. **Clarification is required as to the intent of the Diesel Settlement Agreement but will have to await the filing of the actual Settlement Agreement.**

##### *DSM Costs*

Manitoba Hydro asserts that the direct assignment of DSM costs to the customer classes based on class participation aligns the cost of DSM programs with the classes that participate and benefit. In Manitoba Hydro's view this is the most "cost causal

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<sup>111</sup> Diesel is allocated \$1.049 M in Interest costs on a Rate Base of \$20.657 M. Thus the effect of the \$12.5 M increase in Rate Base due to Diesel 3<sup>rd</sup> party contributions is roughly \$635,000.

<sup>112</sup> Coalition/MH I-8 a) & 12 a)

<sup>113</sup> May Workshop, page 202

<sup>114</sup> Appendix 3, Schedule B1-Amended

approach” as it places cost responsibility on those who cause it and can influence it<sup>115</sup>. This perspective is supported by CA Consulting<sup>116</sup>.

Manitoba Hydro acknowledges that it has multiple objectives in offering DSM programs with the primary ones being meeting the energy needs of the province in the most economic and sustainable manner and assisting customers with managing their electric bills.

Manitoba Hydro also acknowledges<sup>117</sup> that there is an alternative perspective whereby DSM programs can be viewed as a substitute for investment in generation, transmission and distribution and DSM costs would be allocated in proportion to that saved investment. However, it is Manitoba Hydro’s view that taking such a perspective would be a policy decision and moving off the principle of “cost causation” which it characterizes as the “golden rule” for cost allocation<sup>118</sup>. Similarly, CA Consulting takes the view that the costs of DSM should be allocated to those customer classes that cause the costs and not those who might ultimately benefit<sup>119</sup>.

The cost allocation treatment of DSM programs proposed by Manitoba Hydro and supported by CA Consulting fails to consider the overall context in which DSM program are offered. Manitoba Hydro’s mandate is to provide for the continuance of the supply of energy to meet the needs of Manitoba consumers in the most reliable, economic and environmentally sustainable manner. In meeting this mandate Manitoba Hydro’s mission includes promotion of economy and efficiency in the supply and end-use of energy and involves the consideration of all available options for the supply and delivery of energy to Manitobans. These options include both supply-side and demand-side resources.

Planning approaches that consider all available options on an “equal footing” are referred to as “integrated resource planning”. The use of such an approach was

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<sup>115</sup> Workshop, May 13, 2016, page 645

<sup>116</sup> Workshop, May 13, 2016, page 671 (lines 13-17)

<sup>117</sup> Workshop, May 13, 2016, page 645

<sup>118</sup> Workshop, May 13, 2016, page 666

<sup>119</sup> Workshop, May 13, 2016, page 671

endorsed by the MPUB<sup>120</sup> in its recent Needs For And Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan – Final Report which recommended that “integrated resource planning become a cornerstone of a new clean energy strategy for the Province of Manitoba”<sup>121</sup>. Subsequently, Manitoba Hydro has indicated that integrated resource planning is part of its core business activities<sup>122</sup>. Indeed, Manitoba Hydro has indicated that DSM is part of the cost of a least cost package of meeting domestic energy and capacity requirements<sup>123</sup> and that (subject to the concurrence of the Minister) all economic DSM opportunities are part of its overall plans to meet the province's future energy needs<sup>124</sup>.

DSM programs are designed to encourage customers (and other stakeholders) to undertake initiatives that will improve the efficiency of energy use and thereby reduce the overall demand for electricity and the need for new supply resources. While customers can benefit through lower electricity bills from availing themselves of energy efficiency opportunities there are usually other costs<sup>125</sup> involved which will influence the customer participation as well as other barriers<sup>126</sup>.

The purpose of DSM programs is to target efficiency opportunities that would otherwise not be pursued by customers but that are “economic” from society's and the utility's perspective<sup>127</sup>. Programs are designed so as to “tip the balance” from the customer's perspective (generally through some form of incentive) so as to encourage participation while trying to ensure that the programs are still economic from a utility perspective.

Given this context, while it is factually correct to say that Manitoba Hydro's DSM program costs are the result of customers participating in the programs offered and that these customers benefit (through lower bills) this perspective misses the following key points:

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<sup>120</sup> Page 34

<sup>121</sup> Page 36

<sup>122</sup> 2015/16 & 2016/17 GRA, Tab 8, page 1

<sup>123</sup> Appendix 4, page 6

<sup>124</sup> 2015/16 & 2016/16 GRA, Tab 8, page 2

<sup>125</sup> For example, energy efficient equipment and appliances are typically more expensive. Also there may be installation costs involved when customers undertake energy efficiency measures.

<sup>126</sup> For example, the customer paying the bill may not actually own the equipment.

<sup>127</sup>

- Customers participate because Manitoba Hydro is actively encouraging them (often through additional financial incentives) to do so and that looked at from this broader perspective it is Manitoba Hydro that has “caused the costs”. This situation is fundamentally different from one where a customer seeks service from Manitoba Hydro and, as public utility, it is Manitoba Hydro’s obligation to provide the service and incur the necessary costs to so<sup>128</sup>.
- All potential DSM programs will reduce customers’ bills. Potential DSM programs are screened and the DSM programs offered by Manitoba Hydro consist of those programs that are economic from Manitoba Hydro’s perspective, i.e. reduce the overall cost of the system<sup>129</sup>. Thus the primary focus of DSM programs is that they will benefit all customers.
- If all customers in a rate class were to participate in a particular DSM program then allocating the costs of that DSM program directly to the customer class would effectively “claw back” any financial incentive that was provided to customers and thereby removing their inducement to participate in the first place.

**A more appropriate approach is to view DSM as another resources option available to meet customers’ needs and allocate the costs to customers accordingly. Taking such a perspective is not a “policy decision” but rather reflects a broader view of cost causation that takes into account the underlying reasons why the costs were incurred and who they are intended to benefit.**

During the Workshop Manitoba Hydro suggested that there was an inherent unfairness in such an approach particularly for customers that undertake DSM on their own (at their own cost) and are unable to partake of the DSM programs offered by Manitoba Hydro but who would then be required to pick up part of the costs of Manitoba Hydro’s DSM programs<sup>130</sup>. This observation misses the fact that:

- i. these customers freely chose to undertake their own DSM because they viewed doing so would be a direct benefit to them, while

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<sup>128</sup> Subject to any service extension and capital contribution policies that may apply.

<sup>129</sup> PUB/MH I-27 f)

<sup>130</sup> Workshop, May 13, 2016, page 668



- ii. customers who participate in Manitoba Hydro's DSM programs generally<sup>131</sup> would not have undertaken the associated efficiency improvements without the program, and
- iii. the litmus test for DSM programs is that they contribute to a least cost system<sup>132</sup> which benefits all customers.

**Viewing DSM as a resource option means assigning the DSM program costs to the Generation, Transmission and Distribution Plant functions. This can be accomplished by using the same marginal/avoided cost that are used in evaluating DSM programs to attribute the costs of each DSM program to generation, transmission and distribution as appropriate.** The following table uses the DSM program costs by customer class from PCOSS14-Amended and the avoided costs used to evaluate the DSM programs included in IFF12 to determine the portion of DSM program costs that should be assigned to the Generation, Transmission and Distribution functions.

<b>Table #5 - Interest (000's)</b>					
	<u>Res-&gt;GSL&lt;30<sup>1</sup></u>	<u>Curt. Prog.<sup>2</sup></u>	<u>GSL&gt;30<sup>3</sup></u>	<u>Total</u>	<u>%</u>
Prog	\$5,394	\$1,677	\$809	\$7,879	
Gen.	\$4,404	\$1,677	\$734	\$6,814	86.5%
Trans.	\$453		\$75	\$528	6.7%
Distr.	\$537			\$537	6.8%
Total				\$7,879	
Notes:	1) Includes Residenital, GSS, GSM, GSL<30 & ARL				
	2) Includes Curtailable for GSL>30				
	3) Includes GSL30-100 and GSL>100				
	4) Generation/Transmission and Distribution				
	split based on relative Avoided Costs per				
	Coalition/MH I-19 a) for 2012 DSM Forecast				
	(6.32/0.65/0.77)				

<sup>131</sup> It should be noted that to the extent there may be "free-riders" associated with a particular program these are taken into account in the program's economic evaluation.

<sup>132</sup> Appendix 4, page 6

<b>Table #6 - Depreciation (000's)</b>					
	<u>Res-&gt;GSL&lt;30<sup>1</sup></u>	<u>Curt. Prog.<sup>2</sup></u>	<u>GSL&gt;30<sup>3</sup></u>	<u>Total</u>	<u>%</u>
Prog	\$20,074	\$6,872	\$2,652	\$29,598	
Gen.	\$16,391	\$6,872	\$2,405	\$25,668	86.7%
Trans.	\$1,686		\$247	\$1,933	6.5%
Distr.	\$1,997			\$1,997	6.7%
Total				\$29,598	
Notes:	1) Includes Residenital, GSS, GSM, GSL<30 & ARL				
	2) Includes Curtailable for GSL>30				
	3) Includes GSL30-100 and GSL>100				
	4) Generation/Transmission and Distribution				
	split based on relative Avoided Costs per				
	Coalition/MH I-19 a) for 2012 DSM Forecast				
	(6.32/0.65/0.77)				

For purposes of the COSS, Interest and Depreciation costs associated with Support Activities were functionalized based on Tables 3 and 4 respectively. The Operating costs associated with Support activities were functionalized 86.6% Generation; 6.6% Transmission and 6.8% Distribution. It should be noted that this functionalization is reasonably similar to the 90/5/5 split recently approved for BC Hydro<sup>133</sup>.

The following Table sets out the impact of this alternative approach to allocating DSM costs on the revenue to cost ratios for the various customer classes.

<b>TABLE #7 - RECOMMENDED DSM ALLOCATION</b>											
Customer Class	Corrected PCOSS14-Amended					Impact of Alternative DSM Allocation					
	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	RCC Change
Residential	626,705	588,630	38,166	626,795	100.00%	632,412	588,630	35,514	624,143	98.70%	-1.30%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	130,013	135,035	7,301	142,336	109.50%	1.60%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	136,115	136,080	7,644	143,724	105.60%	1.30%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	198,546	186,797	11,150	197,946	99.70%	0.40%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	98,819	84,956	5,549	90,505	91.60%	0.50%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,515	57,808	3,488	61,296	99.60%	-0.40%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	200,332	189,258	11,540	200,797	100.20%	1.90%
SEP	968	826	-	826	85.40%	968	826	-	826	85.40%	0.00%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	22,088	21,630	380	22,010	99.60%	-0.70%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,480,806	1,401,019	82,565	1,483,584	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	559	7,171	72.10%	-0.50%
Export	256,200	345,233	- 89,033	256,200	100.00%	262,110	345,233	- 83,124	262,110	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%

\*Includes Curtailment Customers

<sup>133</sup> BCUC Order G-47-16, page 11

## Export Class

In its Submission Manitoba Hydro assigns NEB fees directly to the Export Class<sup>134</sup>.

However, in the interrogatory responses Manitoba Hydro acknowledged that the NEB has some involvement in the purchase of power from extra-provincial sources and that it may be reasonable to allocate these fees proportionally to all load consistent with the treatment of power purchases and the trading desk<sup>135</sup>. Manitoba Hydro indicates that changing the treatment would have a negligible impact on the RCCs. **However, given this changed view, it would be appropriate if the allocation of the NEB fees was revised and allocated to all load (domestic and export).** The following table sets out the results of allocating NEB fees as part of the Generation pool and confirms that impacts are minor.

TABLE #8 - RECOMMENDED NEB FEE ALLOCATION											
Customer Class	Corrected PCOSS14-Amended					Impact of Alternative DSM Allocation					
	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	RCC Change
Residential	626,705	588,630	38,166	626,795	100.00%	626,985	588,630	38,508	627,138	100.00%	0.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,511	135,035	7,911	142,946	107.90%	0.00%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,426	136,080	8,252	144,332	104.30%	0.00%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	200,145	186,797	12,024	198,821	99.30%	0.00%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	99,794	84,956	5,981	90,937	91.10%	0.00%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,579	57,808	3,753	61,561	100.00%	0.00%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	205,145	189,258	12,382	201,640	98.30%	0.00%
SEP	968	826	-	826	85.40%	968	826	-	826	85.40%	0.00%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	21,972	21,630	412	22,042	100.30%	0.00%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,487,524	1,401,019	89,224	1,490,243	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	617	7,229	72.70%	0.10%
Export	256,200	345,233	- 89,033	256,200	100.00%	255,392	345,233	- 89,841	255,392	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%

\*Includes Curtailment Customers

In its Submission, Manitoba Hydro also directly assigns the costs of the Affordable Energy Fund (AEF) to the Export Class. The AEF programs are designed to support certain energy objectives which are provided for in the AEF Legislation<sup>136</sup>. The stated purposes of the fund are to provide support for:

(a) programs, services and projects

(i) that encourage and realize efficiency improvements and conservation in the use of power, natural gas, other home heating fuels and water,

<sup>134</sup> Appendix 3, page 4

<sup>135</sup> Coalition/MHG I-16 e)

<sup>136</sup> Bill 24, The Energy Savings Act

- (ii) that encourage and realize the use of renewable energy sources, including earth energy, and
  - (iii) that are designed to reduce greenhouse gas emissions that result from the use of home heating fuels other than natural gas in Manitoba;
- (b) research and development of renewable energy sources and innovative energy technologies; and
- (c) social enterprises, community organizations and other business who assist people or neighborhoods to realize efficiency improvements and conservation in the use of power, natural gas, other home heating fuels and water.

The actual allocation of funds is determined after consultation with the Minister responsible for Manitoba Hydro<sup>137</sup>.

As evident from the above, the purposes of the fund extends well beyond improving efficiency in the use of electricity and include spending in areas that do not have any demonstrated benefit to electricity customers either in terms of system benefits or overall lower electricity bills. The fund exists and Manitoba Hydro contributes to and administers the fund solely as result of government policy and legislation. As a result there is no basis for establishing a cost causality link with Manitoba Hydro's customers. However, the Legislation does state<sup>138</sup>:

*"The corporation is to contribute to the fund from time to time the proportion of its gross revenue from the sale of power to customers outside Manitoba that the corporation, in consultation with the minister, considers necessary to carry out the purposes of the fund"*

**Given this direction as to the source of funds for the AEF it is reasonable for Manitoba Hydro to directly assign the annual costs of the AEF to the Export Class.**

Finally, Manitoba Hydro directly assigns the cost of the Uniform Rate Adjustment (URA) to the Export Class. The implementation of uniform rates was the result of Bill 27 which

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<sup>137</sup> 2014/14 & 2015/16 GRA, Coalition/MH I-66 a)

<sup>138</sup> Bill 24, Section 4(3)

required that “the rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province”<sup>139</sup>. The government at the time characterized move to uniform rates as a policy change<sup>140</sup> and that it was bringing forward a universal, uniform rate because of the “benefits generated through export sales” and that it was “not asking other Manitobans to pay more to provide this uniform rate”<sup>141</sup>. **Given this background for implementation of uniform rates Manitoba Hydro’s proposal to treat the cost of the URA as a policy charge and to assign it directly to the Export Class is reasonable and appropriate.**

## 4.5 Generation Function: Definition, Classification and Allocation

### 4.5.1 Manitoba Hydro Proposal

#### *Definition*

Manitoba Hydro’s proposed Generation function includes all generating facilities, the northern collector circuits, the HVDC facilities (including Dorsey converter facilities and Riel converter facilities (when they are built)) and a share of the communication facilities, administration buildings and general equipment<sup>142</sup>. It also includes the operating costs associated with these facilities as well as the cost of purchased power (including wind), fuel costs, water rentals & assessments and trading desk costs.

This represents a change from the currently approved methodology where the entire cost of Dorsey is included in the Transmission function<sup>143</sup>. Other changes are with respect to the costs directly assigned to Exports versus those that are assigned to the Generation function for allocation to customer classes (including exports). The proposed approach only directly assigns NEB Fees to Exports whereas the currently approved approach also directly assigns to Exports: i) DSM Costs (as discussed in Section 4.4.2); ii) the costs of Purchased Power (including wind); iii) 100% of variable

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<sup>139</sup> Section 39(2.1)

<sup>140</sup> Standing Committee on Public Utilities and Resources, June 18, 2001, page 96

<sup>141</sup> Ibid, page 97

<sup>142</sup> Appendix 3.1, page 22 and Appendix 3, page 3

<sup>143</sup> PUB-MFR 13

thermal plant costs (i.e., fuel and variable O&M); iv) 50% of fixed thermal plant costs; and v) 100% of Trading Desk Operations costs<sup>144</sup>.

### *Classification*

Manitoba Hydro's proposed COS methodology divides its Generation function costs into two cost "pools"<sup>145</sup>. The first consists of those costs that are to be allocated to domestic customers and dependable exports while the second consists of those costs that are to be allocated to domestic customers and all exports. Both cost pools are notionally classified as energy-related.

The first cost pool includes all the costs associated with hydro facilities<sup>146</sup>, wind purchases and thermal generation (both natural gas and coal<sup>147</sup>) along with the HVDC facility costs<sup>148</sup> and northern circuit costs that are functionalized as Generation. The second cost pool includes power purchases & transmission fees; water rentals & variable hydraulic O&M; and trading desk costs<sup>149</sup>.

In contrast, the currently approved COSS methodology only has one generation cost pools (also notionally classified as energy-related). The following table contrasts the two methodologies' treatment of Generation Costs.

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<sup>144</sup> Coalition/MH I-85 g)

<sup>145</sup> Submission, page 17

<sup>146</sup> Excluding those specifically assigned to the Pool #2

<sup>147</sup> Manitoba Hydro states (Appendix 1, page 4) that, by virtue of Bill 15, coal-fired generation can no longer be used to support exports and should be allocated solely to the domestic customer classes. However, to avoid the complexity of creating a third generation cost pool, Manitoba Hydro proposes to include this facility in with those whose costs are allocated to both domestic customer classes and dependable exports and indicates there is a minimal RCC impact (Coalition/MH I-63 a).

<sup>148</sup> Lines and the Dorsey converter

<sup>149</sup> Submission, page 17

**Table #9**  
**COSS Treatment of Generation Costs**

<b>Item</b>	<b>Current COSS Methodology</b>	<b>Proposed COSS Methodology</b>
Generation Pools Employed	Pool – Domestic Classes plus All Exports (not served by direct assignments)	Pool #1 – Domestic Classes plus Dependable Exports Pool #2 – Domestic Classes plus All Exports
Purchased Power	Directly Assigned to Exports	Pool #2
Wind Purchases	Directly Assigned to Exports	Pool #1
Thermal Plant Costs & O&M	50% - Exports 50%- Pool	Pool #1
Thermal Fuel	Directly Assigned to Exports	Pool #1
Hydro Plant Costs	Pool	Pool #1
Water Rentals and Variable Hydro O&M	Pool	Pool #2
Trading Desk	Directly Assigned to Exports	Pool #2
HVDC Facilities & Northern Circuits	Pool	Pool #1
NEB Fees	Directly Assigned to Exports	Directly Assigned to Exports
DSM Costs	Directly Assigned to Exports Note: Energy Savings added back to Domestic Classes for Allocation purposes	Directly Assigned to Domestic Classes.

Note: Coalition/MH I-85 g) indicates that the current PUB directed methodology has only one Generation Pool, which allocates costs to domestic customers plus unserved dependable and opportunity exports. PUB MFR-13 indicates that there are two Generation Pools – one consisting of just domestic customers and a second consisting of domestic plus unserved exports. The above Table reflects the methodology as set out in Coalition/MH I-85 g).

### *Allocation*

The current PUB directed methodology allocates the costs in the Generation pool to the domestic classes and unserved exports based on a weighted energy allocator that recognizes the time-differentiated value of energy. Application of the weighted energy allocator involves applying the relative<sup>150</sup> average (inflation adjusted) SEP prices over the past eight years to each customer class' forecast energy use in each of the 12 SEP time periods<sup>151</sup> to derive a total weighted energy value for each customer class. These relative values are then used to allocate the Generation pool costs to customer classes<sup>152</sup>.

The proposed COSS methodology generally utilizes the same approach but incorporates an additional capacity component in the weighted energy allocator. The value of the Reference Discount<sup>153</sup> used in the CRP is utilized as the value of capacity. The \$/kW value is converted to a \$/kWh equivalent and added to the SEP value for the peak period in each season<sup>154</sup>.

### 4.5.2 ECS Comments

#### *Definition*

Manitoba Hydro's proposal includes changes to both the definition of the Generation as well as to what Generation costs are directly assigned versus allocated to customer classes.

**In terms of definition, the key change is the inclusion of the Dorsey converter facilities in Generation as opposed to Transmission. This change is consistent with Manitoba Hydro's overall approach of functionalizing transmission facilities that are utilized solely to bring Generation to and incorporate it into the Grid network as Generation. It is this same approach that leads Manitoba Hydro to**

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<sup>150</sup> Summer Off-Peak is set equal to 1.0

<sup>151</sup> Four seasonal periods combined with Peak, Shoulder and Off-Peak periods in each season.

<sup>152</sup> Order 117/06, pages 22 and 47

<sup>153</sup> Per PUB/MH I-51, the Reference Discount represents the value of Curtailable load to Manitoba Hydro and is the basis for the discount provided to customers participating in the Curtailable Rate Program (CRP).

<sup>154</sup> Submission, page 20



functionalize the northern collectors, the northern converter stations and the Bipole lines<sup>155</sup> as Generation.

It is noted that a similar same approach is used by BC Hydro which in its most recent cost of service proposals approved by the BCUC<sup>156</sup> continues to re-functionalize transmission assets used to connect its remote hydro facilities to the transmission grid as Generation. This approach is also consistent with the industry standards regarding the designation of transmission facilities for purposes of setting Open Access Transmission Tariffs (OATT)<sup>157</sup> and with the fact that incorporation costs (i.e., the costs of transmission facilities required to incorporate new generation into the grid network) are considered when evaluating different Generation options<sup>158</sup>.

With respect to the proposed inclusion of purchases (including wind purchases), trading desk costs, thermal fuel costs and all versus 50% of thermal plant costs in the Generation pool as opposed to directly assigning them to Exports:

- Under median water conditions power purchases are made primarily to support export sales. However, under low water conditions they would be required to serve domestic load and therefore serve all loads depending upon system conditions<sup>159</sup>. Given this perspective and the discussion in Section 3.2 to consider the benefits provided under the full range of likely operating conditions, **it is reasonable to allocated power purchases to more than just the Export class.**
- Wind purchases are not typically dispatchable and, at any given time, contribute to the overall supply of energy that is used to meet both domestic and export loads<sup>160</sup>. **As a result, it is also reasonable to allocate the costs for wind purchases to more than just the Export class.**

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<sup>155</sup> This will include Bipole III when it comes into service

<sup>156</sup> BCUC Order G-47-16, page 13

<sup>157</sup> Coalition/MH I-37 a) – d). Pursuant to its Coordination Agreement with MISO, Manitoba Hydro relies on 7-factor test and used and useful criteria established by the US FERC for purposes of determining tariffable transmission facilities. Based on these criteria the converter facilities at Dorsey (and Riel) are ineligible for inclusion in the transmission tariff.

<sup>158</sup> Manitoba Hydro's 2013 NFAT Submission, Chapter 9, page 6

<sup>159</sup> Coalition/MH I-61 b) and PUB/MH I-12 a). See also May Workshop, page 108

<sup>160</sup> PUB/MH I-36 d)

- The trading desk supports both exports and purchase activities and, therefore, it would not be appropriate to directly assign 100% of the cost to the Export class as, at times, purchases are used to support domestic load<sup>161</sup>. In earlier proposals Manitoba Hydro split the trading desk costs between exports and domestic based on an analysis of the staff that are associated with export activities<sup>162</sup>. **The current proposal simplifies this approach by including the trading desk costs with the other Generation costs that are to be allocated between domestic customers and exports. Given the materiality of the dollars involved (\$13 M)<sup>163</sup> this approach is reasonable.**
- Thermal fuel and plant costs consist of fueling, operating, depreciation and interest<sup>164</sup> costs for Manitoba Hydro's coal and natural gas-fired generation. **With respect to the coal-fired generation, in accordance with Bill 15 it can no longer be used to support exports therefore it should not be directly assigned to exports<sup>165</sup>.** In the case of natural gas-fired generation, while technically it could be used to support exports (and the original investment in the Brandon gas-fired units was justified in part on that basis<sup>166</sup>) current economics and the nature of the export contracts result in the units not being used to support exports<sup>167</sup>. As a result, **it is appropriate to not directly assign any of the costs of natural-gas fired generation to exports.**

Manitoba Hydro effectively sub-functionalizes Generation into two pools, one of which consists of Generation cost that are to be allocated to all domestic load plus dependable exports sales and a second which consists of those costs that are to be allocated to all domestic load and all exports (including both dependable and opportunity exports). The

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<sup>161</sup> PUB/MH I-14

<sup>162</sup> PUB/MH I-14

<sup>163</sup> Coalition/MH I-64 a)

<sup>164</sup> Including a share of capital taxes and net income.

<sup>165</sup> Submission, page 4

<sup>166</sup> May Workshop, page 181

<sup>167</sup> PUB/MH I-2 b) and PUB/MH I-13 d) – e). See also May Workshop, page 128

follow chart (taken from the Submission) provides a simplified view of this sub-functionalization<sup>168</sup>.

		Dependable		Opportunity
		Domestic	Export	Export
Generation Pool 1	Hydraulic Generation	✓	✓	✗
	Wind	✓	✓	✗
	Natural Gas Thermal	✓	✓	✗
	Coal Thermal	✓	✓	✗
Generation Pool 2	Power Purchases & Transmission Fees	✓	✓	✓
	Water Rental & Variable Hydraulic O&M	✓	✓	✓
	Trading Desk	✓	✓	✓

The purpose of the two Generation pools builds on Manitoba Hydro's proposal for two Export classes (dependable exports and opportunity exports) and permits the COSS to distinguish between those costs that dependable versus opportunity exports should be viewed as responsible for.

As discussed above (Section 4.2), Manitoba Hydro has established two export customer classes. The first is a dependable export customer class which, for purposes of the COSS, is notionally considered to have the same service requirements (particularly in terms of reliability) and responsibility for embedded costs as firm domestic load. In contrast, the second export class (opportunity exports), is considered to be served from surplus energy and, as a result, have no responsibility for embedded costs.

Given that, under various conditions, power purchases can be used to support opportunity sales well as domestic firm load and dependable sales it is reasonable to include them and the trading desk costs in the second Generation pool. Similarly, since opportunity sales are primarily sourced from hydro generation in excess of dependable energy it is reasonable to include water rentals and variable hydraulic O&M costs in the second Generation pool.

<sup>168</sup> Submission, page 17

One issue that does arise is the inclusion of thermal generation costs, particularly those related to coal-fired generation in the first Generation pool which is allocated to domestic load plus dependable exports. Based on the preceding discussion a case can be made that these costs should be allocated entirely to the domestic customer classes. Indeed, Manitoba Hydro has acknowledged that it would be appropriate to assign coal<sup>169</sup> and natural gas-fired generation<sup>170</sup> only to the Domestic class. Manitoba Hydro's proposal to include these costs in the Generation pool is made to avoid the complexity of introducing a separate pool and allocation for these cost given the minimal impact such a change is likely to have<sup>171</sup>.

It is noted that the added complexity of assigning thermal generation to just domestic load extends well beyond the need for a third pool for Generation costs. If thermal generation is to be assigned solely to the domestic classes then the allocators for the domestic classes used to assign the balance of the generation costs between domestic classes and dependable exports would need to be adjusted in some manner to account for the fact that a portion of their service requirement are being met by thermal generation. **Overall, given the magnitude of the dollars involved and the complexity of separating out thermal stations, Manitoba Hydro's proposed treatment of thermal generation is reasonable.**

### *Classification*

Both Generation pools are notionally classified as energy-related and allocated to the relevant customer classes using a weighted energy values where the "weights" by period take into account both the value of capacity and energy based on a proxy for marginal costs.

As was noted in the ECS evidence filed during the 2002 Status Update proceeding, apart from fuel costs, which can readily be classified as energy-related, the costs associated with the Generation function (e.g., depreciation, interest and plant O&M) are generally associated with the provision of both demand and energy. However, there is no generally accepted approach for classifying this portion of generation costs.

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<sup>169</sup> Submission, page 4. See also May Workshop, page 177

<sup>170</sup> May Workshop, pages 178-179

<sup>171</sup> Submission, page 4 and Coalition/MH I-63 a)

Rather, there are a number of different approaches that could be used<sup>172</sup>. Most of these approaches try to capture, by one means or another, the fact that utilities typically have a number of generation options to choose from and that the choice (say between hydraulic and fossil) takes into account both the energy and the capacity requirements of the utility's customers and that significant fixed costs (in the form of depreciation and financing expense) are frequently incurred in order to reduce energy costs over the long run or increase overall energy production.

Recognizing that one cannot accurately determine the portion of costs that were incurred to support energy versus capacity requirements, the use of marginal costs allows the cost of service methodology to reflect cost causation by capturing the relative costs that the utility would incur today in order to meet demand and energy needs.

In response to CA Consulting's 2012 Report, Manitoba Hydro indicated that it would explore the impacts of using the Equivalent Peaker methodology but that it would expect the resulting demand/energy split to be approximately 15/85<sup>173</sup>. In interrogatories<sup>174</sup> for this proceeding MIPUG explored the implications of applying the Equivalent Peaker method suggesting that the demand/energy split would be in the order of 30/70.

However, the analysis suggested in the interrogatories fails to account for the fact that the total generation costs reported by Manitoba Hydro are based on the costs of facilities that have been put into place over decades while the equivalent peak cost used was based on current costs. This mismatch in costs is one of the number of issues that Manitoba Hydro has flagged with the Equivalent Peaker method<sup>175</sup>. It is noted that correcting this mismatch by restating the existing generation resources on a common dollar basis with the cost of the equivalent peaker would increase the overall value of Generation and decrease the percentage deemed to be demand-related.

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<sup>172</sup> Approaches used elsewhere include using: i) system load factor, ii) marginal capacity and energy costs, iii) individual plant capacity factors, and iv) peaking plant costs to determine demand costs.

<sup>173</sup> Appendix 4, page 8

<sup>174</sup> MIOUG/MH I-10

<sup>175</sup> MIPUG/MH I-10 a)

In response to MIPUG/MH I-10 h) Manitoba Hydro demonstrates that when the demand/energy split is in the order of 20/80 to 10/90 the allocation results are not much different from those that arise from Manitoba Hydro's proposed approach for classifying and allocating Generation costs. **As a result, continued use of Manitoba Hydro's approach of classifying Generation costs as notionally energy-related and allocating them to customer classes on a weighted energy basis is reasonable and the preferred approach given the alternatives available.**

### *Allocation*

The Generation allocation methodology approved by the PUB following the 2005 COS Review involved weighting the energy use of each customer class by the average SEP price in each period<sup>176</sup>. At the time of the 2005 COSS review Manitoba Hydro expressed the view that the SEP prices adequately captured not only the relative marginal cost of energy by period but also reflected the cost of capacity<sup>177</sup>.

However, in the current Submission, Manitoba Hydro notes that due to a change in market conditions the capacity component of energy supply may no longer be reflected in the difference between the on-peak and off-peak energy prices that underlie the SEP prices<sup>178</sup>. One of the reasons cited for this is the appearance of the voluntary MISO capacity market starting in April 2009<sup>179</sup>. When asked<sup>180</sup> for the analysis of changes in market conditions, Manitoba Hydro referred to the responses to Coalition/MH I-56 c) & e) which provided the following comparisons of peak and off-peak values.

	Average On/Off Peak Ratio		
	Annual	Summer	Winter
1999/00 to 2008/09	2.0	2.4	1.7
2009/10 to 2014/15	1.6	1.8	1.4
Percent Decrease	-21%	-25%	-17%

<sup>176</sup> The prices were averaged over the most recent eight years for which actual values were available. For PCOSS08 this was 1999-2005 and for the current Submission this would be 2005-2012. Coalition/MH I-53 a) – d)

<sup>177</sup> 2005 COSS Review, CAC/MSOS/MH I-11 e)

<sup>178</sup> Submission, page 20

<sup>179</sup> Appendix 2, page 18 and Coalition/MH I-56 e)

<sup>180</sup> GAC/MH I-53

Also, supporting this view is the fact that peak period opportunity prices were roughly equivalent to (and often exceeded) peak period dependable sale prices up to 2009, after which they were materially lower<sup>181</sup>.

However, there are a number of issues with Manitoba Hydro's proposed inclusion of a capacity adder. First, based on its current methodology Manitoba Hydro uses historical SEP data for the period 2005-2012 to determine the energy weightings for each of the 12 periods in PCOSS14-Amended. Then, in its proposed methodology Manitoba Hydro has incorporated a "capacity adder" for each of the eight years, including the 2005-2009 period prior to the "change in market conditions"<sup>182</sup>. Based on the rationale provided by Manitoba Hydro, if a capacity adder is needed then it should only be included for those years after 2009.

Furthermore, while the MISO Voluntary Capacity Auction was implemented April 1, 2009, the MISO Planning Resource Auction was not implemented until 2013 and it is this latter market that Manitoba Hydro participates in and that through which utilities can obtain capacity resources that will contribute to their long term resource adequacy for planning purposes<sup>183</sup>. In contrast, the data period used to determine the weighted energy allocators in PCOSS14- Amended is from 2005-2012 which entirely precedes the implementation date for the MISO Planning Resources Auction.

During the course of the May Workshop Manitoba Hydro acknowledged that this was an issue that should be considered<sup>184</sup>. Adopting Manitoba Hydro's approach but including a capacity adder only for the years 2010-2012 or excluding it entirely would change the peak period weighting factors as follows.

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<sup>181</sup> Coalition/MH I-5 a)

<sup>182</sup> May Workshop, page 168

<sup>183</sup> Coalition/MH I-54 a) – b). See also May Workshop, page 175

<sup>184</sup> May Workshop, page 172

<b>Table #10</b>			
<b>Peak Period Energy Weighting Factors</b>			
Period	Corrected PCOSS14-Amended	Include Capacity Adder for 2010-2012	No Capacity Adder
Spring Peak	4.966	4.147	3.657
Summer Peak	5.870	5.046	4.560
Fall Peak	5.169	4.350	3.860
Winter Peak	5.967	5.148	4.659

Including a capacity adder for only the years 2010-2012 versus all eight years would impact the COSS results by rate class as follows.

<b>TABLE #11 - CAPACITY ADDER FOR 2010-2012 ONLY</b>											
Customer Class	Corrected PCOSS14-Amended					Impact of Capacity Adder for 2010-2012					
	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	RCC Change
Residential	626,705	588,630	38,166	626,795	100.00%	627,138	588,630	38,358	626,988	100.00%	0.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,247	135,035	7,862	142,897	108.10%	0.20%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,207	136,080	8,205	144,285	104.40%	0.10%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	199,671	186,797	11,945	198,742	99.50%	0.20%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	99,474	84,956	5,936	90,893	91.40%	0.30%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,720	57,808	3,746	61,554	99.70%	-0.30%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	205,643	189,258	12,362	201,619	98.00%	-0.30%
SEP	968	826	-	826	85.40%	968	826	-	826	85.40%	0.00%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	22,062	21,630	416	22,046	99.90%	-0.40%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,487,129	1,401,019	88,831	1,489,850	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	615	7,227	72.60%	0.00%
Export	256,200	345,233	-	256,200	100.00%	255,787	345,233	-	255,787	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%

Second, Manitoba Hydro has indicated that since the changes in the MISO markets largely coincided with the 2008 economic downturn and the drop in natural gas prices, the changes in the on/off-peak ratio seen in Coalition/MH I-56 e) cannot be reasonably attributed entirely to a reduction in scarcity premium reflected in on-peak SEP prices and which is meant to be a proxy for capacity costs.



This change in natural gas price is evident from information<sup>185</sup> Manitoba Hydro filed in the 2014/15 & 2015/16 GRA review which shows a significant decrease in natural gas prices post 2008/09. This same change in natural gas prices could account not only for some of the change in the on/off-peak ratio for SEP prices but also for the fact that peak period opportunity prices were materially less than peak period dependable prices post 2009<sup>186</sup>.

Third, recognizing that the peak period definition used for the weighted energy allocator differs from that used in the MISO market it is important to look at how the relative on/off-peak ratios for the weighted energy allocator have changed post-2009. The following table compares the weighting ratios use in PCOSS06 and PCOSS08 with those that would result from using the current methodology for PCOSS14 (i.e. SEP prices for 2005-2012 with no capacity adder).

<b>TABLE #12 - COMPARISON OF PEAK PERIOD WEIGHTS USED FOR GENERATION ALLOCATION</b>			
	PCOSS06 <sup>1</sup>	PCOSS08 <sup>2</sup>	PCOSS14- Amended <sup>3</sup>
Spring Peak	2.684	2.513	3.657
Summer Peak	3.114	3.258	4.560
Fall Peak	2.229	2.624	3.860
Winter Peak	3.286	3.406	4.659
Notes: 1) PUB-MFR 7 2) Coalition/MH I-53 b) 3) PCOSS14-Amended Model – with Fall/Winter Correction and No Capacity Adder			

The results do not support the premise that market conditions have changed post-2009 such that the SEP differentials no longer capture the value of capacity. Indeed these

<sup>185</sup> PUB/MH I-81 a)

<sup>186</sup> Unless the terms of the longer term dependable export contracts directly linked the electricity price to natural gas prices the post 2009 dependable export prices would not track the decrease in natural gas prices to the same extent opportunity export prices would.

results show that rather than the on/off peak differential decreasing with the use of post-2009 data the opposite has occurred.

Fourth, as noted above, the peak period definition as used by MISO and for purposes of Manitoba Hydro's CRP differs from that used for the SEP and includes some of the SEP shoulder hours<sup>187</sup>. As a result, a question arises as to whether or not the capacity adder (if one is deemed to be required) should be assigned to just the SEP peak period hours or also pro-rated over those SEP's shoulder hours that form part of the MISO peak period<sup>188</sup>.

Questions also arose at the May Workshop as to why the capacity adder should be included in the Spring and Fall peak periods<sup>189</sup>. Indeed, Manitoba Hydro has acknowledged that it has not "landed on" what periods the adder should be applied to<sup>190</sup>. Another relevant consideration with respect to this question would also be the peak period definition that Manitoba Hydro proposes to use in its future industrial time of use rate proposal<sup>191</sup>

Finally, there is a substantial difference between the annual value of the capacity as set by either the current MISO Planning Resource Auction<sup>192</sup> (i.e., roughly \$0.10/kW/month –US) or the earlier Voluntary Capacity Market (where the median value between 2009 and 2013 was even lower<sup>193</sup>) and the annual cost<sup>194</sup> of a "peaker unit" such as a simple cycle combustion turbine (i.e. roughly \$5.40/kW/month – US). This difference, in itself, begs a number of questions.

Given the low value of capacity assigned through the auctions, is it the introduction of the capacity markets that led to the reduced influence of capacity consideration in the peak period opportunity prices or was it the change in the outlook for the supply/demand balance as a result of the economic turndown? If the later, this would

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<sup>187</sup> Coalition/MH I-55 e)

<sup>188</sup> May Workshop, pages 173-174

<sup>189</sup> May Workshop, page 139

<sup>190</sup> May Workshop, page 141

<sup>191</sup> Coalition/MH I-55 g)

<sup>192</sup> Coalition/MH I-54 e)

<sup>193</sup> Undertaking #3

<sup>194</sup> Appendix 2, page 20

signal a decrease in the current cost of capacity levelized over the planning period<sup>195</sup> which may be the appropriate value to reflect in the energy weightings. It similarly gives rise to debate as to what the appropriate value for the capacity adder should be. The CRP Reference Discount proposed by Manitoba Hydro falls somewhere in the middle of the range.

**Overall, the question of whether or not a capacity adder should be included in the energy weighting factor determination requires more consideration in terms of: i) is one needed, ii) what the value should be and iii) in what hours/seasons should it be incorporated. At this time, and particularly for PCOSS14-Amended, it is premature to include a capacity adder.** The following table sets out the impact on the COSS results of not including the capacity adder.

TABLE #13 - NO CAPACITY ADDER											
Customer Class	Corrected PCOSS14-Amended					Impact of No Capacity Adder					
	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	RCC Change
Residential	626,705	588,630	38,166	626,795	100.00%	627,425	588,630	38,486	627,116	100.00%	0.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,113	135,035	7,877	142,911	108.20%	0.30%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,113	136,080	8,223	144,303	104.50%	0.20%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	199,435	186,797	11,965	198,762	99.70%	0.40%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	99,303	84,956	5,943	90,899	91.50%	0.40%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,843	57,808	3,765	61,572	99.60%	-0.40%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	206,080	189,258	12,424	201,682	97.90%	-0.40%
SEP	968	826	-	826	85.40%	968	826	-	826	85.40%	0.00%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	22,124	21,630	421	22,051	99.70%	-0.60%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,487,403	1,401,019	89,104	1,490,122	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	617	7,229	72.70%	0.10%
Export	256,200	345,233	- 89,033	256,200	100.00%	255,513	345,233	- 89,720	255,513	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%

\*Includes Curtailment Customers

Given Manitoba Hydro's claim that Bipole III is driven by the demand for reliability<sup>196</sup>, another issue raised at the May Workshop<sup>197</sup> was whether the cost of BPIII should be allocated using the weighted energy allocator or using a demand-related allocator such as 1CP or 2CP.

The need for BP III, as presented in Manitoba Hydro's submission to the CEC Review of the project, is to ensure that Manitoba Hydro's northern generation can be reliably delivered to the transmission system and made available to serve Manitoba Hydro's

<sup>195</sup> Coalition/MH I-57 a)

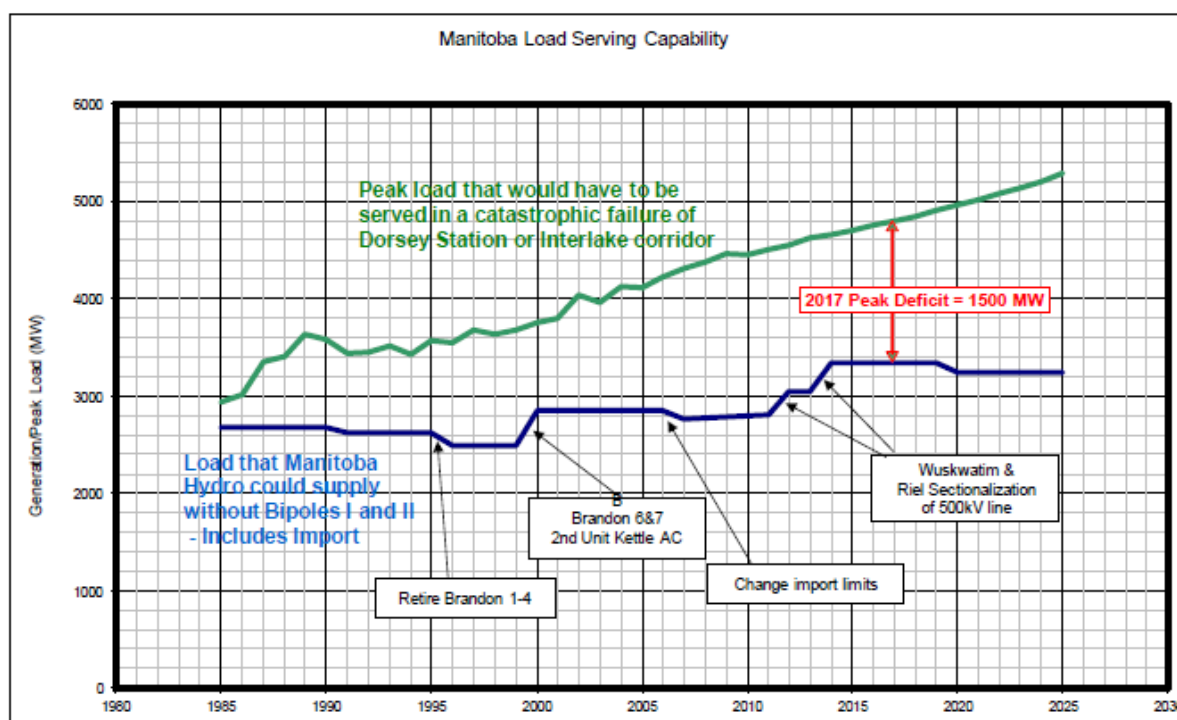
<sup>196</sup> MIPUG/MH I-15 n)

<sup>197</sup> Page 551

domestic load. This is illustrated by the following conclusions from the Needs and Alternatives chapter<sup>198</sup>:

*A system reliability initiative, Bipole III is needed to provide a back-up transmission path, recognizing the existing vulnerability of Bipoles I and II, which share a common transmission line corridor and a single terminus at Dorsey Station.*

The extent of the need was illustrated in the following graphic (Figure 2.2-1) from the same chapter.



It should be noted that the 1,500 MW shortfall calculation for 2017 was deemed to be a conservative estimate and expected to grow with time<sup>199</sup>. It is also noted<sup>200</sup> that the 1,500 MW shortfall would lead to a domestic supply deficit for roughly 1/3 of the year which would also grow with time. **As a result, it is reasonable to consider Bipole III an integral part of the overall facilities (including Bipoles I & II) needed to deliver**

<sup>198</sup> Page 2-2

<sup>199</sup> CEC/MH-VI-26 a) & c)

<sup>200</sup> Manitoba Hydro's CEC Submission, page 2-7

## **northern generation to Manitoba Hydro's domestic load and allocate as part of Generation.**

### **4.6 Transmission Function: Definition, Classification and Allocation**

#### **4.6.1 Manitoba Hydro Proposal**

##### *Definition*

Manitoba Hydro defines the Transmission Function as including lines operating at 100 kV or higher, those substations with low voltage at 230 or 115 kV, the high voltage portion of those substations that step power down from above to below 100 kV<sup>201</sup> and substation transformers in stock<sup>202</sup>. It also includes a share of communication facilities, administration buildings, and general equipment as discussed in Section 4.3.1.

However, as noted already, it excludes the cost of the HVDC facilities (including the Dorsey converter) and the northern collector<sup>203</sup>.

Manitoba Hydro has also established an Ancillary Services function, where ancillary services are those necessary to support the transmission of capacity and energy from resources to load while maintaining a reliable operation of the system<sup>204</sup>. While there are effectively six types of Ancillary Services the function only includes the costs for the Scheduling, System Control and Dispatch Service all of which are recorded as Transmission in Manitoba Hydro's financial systems<sup>205</sup>. Furthermore, they are segmented for presentation purpose only and re-aggregated with Transmission for purposes of allocation<sup>206</sup>. As a result, for the purposes of these comments, the Ancillary Services function is assumed to be part of the Transmission function.

The Transmission function is segmented into three sub-functions: i) Tariffable Transmission, ii) Non-Tariffable Transmission and iii) Interconnections. The Non-Tariffable Transmission sub-function includes the cost of two radial taps to >100 kV customers as well as a number of assets that were formally in the Transmission or Sub-

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<sup>201</sup> Submission, page 9

<sup>202</sup> Appendix 3.1, page 23

<sup>203</sup> GAC/MH I-6

<sup>204</sup> Appendix 3.1, page 23

<sup>205</sup> Coalition/MH I-27 g) and 30 a)

<sup>206</sup> Coalition/MH I-27 g)

Transmission function but, upon review<sup>207</sup>, were determined to be assets operating at >100 kV but not eligible for inclusion in transmission for purposes of determining the OATT<sup>208</sup>. The Interconnections includes the cost for its four US transmission interconnections and, in the future, will also include the cost for the Manitoba-Minnesota Transmission Project/Great Northern Transmission Line (“MMTP/GNTL”) interconnections<sup>209</sup>.

### *Classification*

Manitoba Hydro classifies the transmission costs associated with Tariffable and Non-Tariffable Transmission as demand-related, along with the costs in the Ancillary Services function.

The costs for Interconnections are notionally classified as energy-related<sup>210</sup>.

### *Allocation*

Costs classified as demand-related are allocated to customer classes (i.e., domestic classes and dependable exports) based on a 2CP allocation factor (using each class’ contribution to the top 50 hours in each of the winter and the summer)<sup>211</sup>. The only exception is the MISO fees which are allocated to the domestic classes and all exports (dependable and opportunity)<sup>212</sup>.

The Interconnection costs classified as energy related are allocated to customer classes using the same weighted energy allocator as is used for Generation costs<sup>213</sup>.

## 4.6.2 ECS Comments

### *Definition*

In order to account for and track radial customer taps and other assets that are transmission but not eligible for inclusion in the OATT Manitoba Hydro has segmented the costs in its Transmission function as between those that are Tariffable and Non-

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<sup>207</sup> Coalition/MH I-38

<sup>208</sup> Coalition/MH I-37 and GAC/MH I-6

<sup>209</sup> Submission, page 21

<sup>210</sup> Submission, page 21

<sup>211</sup> Appendix 3, Schedule E5-Amended

<sup>212</sup> Coalition/MH I-65 a) & b)

<sup>213</sup> Submission, page 21. Also, per Appendix 3, the allocators E12 and E15 have the same values.

Tariffable. **The introduction of a Non-Tariffable sub-function is an improvement over the current treatment of radial taps and other transmission voltage assets which functionalized them as Sub-Transmission<sup>214</sup>**, effectively overstating the cost of serving customers at voltages less than 100 kV.

The current proposal has also revised the definition of Interconnections relative to that initially proposed at the time of the 2005 COSS review. At the time of the earlier review, Interconnections included all lines that crossed the Manitoba Border and therefore also included the cost of interconnections with Saskatchewan and Ontario. It also included the costs of the six substations<sup>215</sup>. Part of the rationale for the change in definition is the complexity in identifying the portion of interconnections with Canadian provinces that is truly only used to deliver to/import power from outside the province and the fact that the substations concerned also had lines emanating from them that served Manitoba domestic load<sup>216</sup>. **Overall the change in the definition of Interconnections is reasonable.**

However, there is an issue related to the determination of Transmission costs by sub-function as determined by the COSS model. The Settlement Cost Centres (SCC) used in Manitoba Hydro's financial systems track the costs of individual transmission facilities in sufficient detail in order to allow the operating and depreciation costs associated with the HVDC facilities and the northern collector circuits to be identified and re-functionalized as Generation<sup>217</sup>. The SCC are also in sufficient detail to allow the costs associated with the substations and AC transmission lines to be functionalized to transmission and subsequently sub-functionalized<sup>218</sup>.

There are also a number of SCC that are associated with common Transmission activities (e.g., planning, system operation and system protection) that are assigned to functions based on the functionalization of Transmission Operating costs<sup>219</sup>. For these costs, it appears that this "functionalization" is based the initial functionalization of costs

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<sup>214</sup> PUB MFR 13

<sup>215</sup> Coalition/MH I-68 a)

<sup>216</sup> May Workshop, pages 458 & 460

<sup>217</sup> Coalition/MH I-27 d)

<sup>218</sup> Coalition/MH I-27 a) – c)

<sup>219</sup> Coalition/MH I-27 a) – c)

as established by Manitoba Hydro's financial systems and is not revised by the model when assets are transferred (as part of the COSS) between functions as is the case with Dorsey and the HVDC facilities<sup>220</sup>. Furthermore, when the costs for the Interconnections and Non-Tariffable sub-function are determined they do not include an allocation of the share of the costs associated with these "common" SCCs<sup>221</sup>. **These shortfalls could be readily addressed by incorporating the functionalization/sub-functionalization of the common SCC costs into the COSS model.**

There is a similar issue with the shares of Buildings, Communications & Control, General Equipment and Regulated Assets that are functionalized as Transmission, in that there appears to be no sub-functionalization of these costs to Interconnections or Non-Tariffable Transmission rather they are all included in Tariffable Transmission<sup>222</sup>. **Again, this issue could be addressed by incorporating not only the functionalization (per Section 4.3.2) but also the sub-functionalization of these costs into the COSS model.**

Finally, Manitoba Hydro has acknowledged that not all of the AC lines that serve to link generation to the transmission system have been removed from the Non-Tariffable Transmission sub-function and included in Generation<sup>223</sup>. **These lines should be identified and the required revisions should be incorporated in any future COSS.**

#### *Classification/Allocation*

In cost of service studies Transmission costs are typically classified as demand-related. Therefore, Manitoba Hydro's proposed classification of the Tariffable and Non-Tariffable sub-functions is in line with industry norms.

Transmission costs are generally allocated based on each customer class' contribution to the system peak in a pre-determined number of months where the months chosen are based on the utility's overall load characteristics and meant to capture those months where the load is highest.

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<sup>220</sup> This can be seen by virtue of the fact that the allocation of common Transmission costs (Schedules C6 and C12) does not change as between PCOSS14 and PCOSS14-Amended.

<sup>221</sup> May Workshop, pages 188-189 and page 470

<sup>222</sup> May Workshop, page 470

<sup>223</sup> May Workshop, pages 453 & 487



Depending upon the system load shape this can result in using an allocation factor based on peak contribution in the highest one month, the highest 2 months, the highest 4 months or even all 12 months<sup>224</sup>. Manitoba Hydro has proposed to use the highest 50 hours by season and to include both the winter and summer seasons. Based on 2011/12 data used for PCOSS14-Amended<sup>225</sup>, this captures hours from the summer months of June, July and August and from the winter months of December, January and February<sup>226</sup>. Manitoba Hydro explains that the use of the single top hour in a month (or selected months) as opposed to the top 50 hours would not necessarily be representative of all hours in which the peak could occur and may bias the allocation of peak-related costs towards a particular class or classes of service depending upon the year(s) the load research was based on<sup>227</sup>. **Given that the use of a set number of hours as opposed to the single hour in each month serves to stabilize the results from year to year<sup>228</sup> it is a reasonable approach.**

With respect to the choice of 50 hours per season, Manitoba Hydro has acknowledged that there is no “magic” to the number and that they’ve been unable to locate the research used when it was originally established<sup>229</sup>. This may warrant review at some future date but is not viewed as critical at this point.

Another issue that arose during the Workshop is the inclusion of summer as well as winter hours. The concern being that while the winter and summer peaks are reasonably equivalent when one includes all exports, if just dependable exports are included then the winter 2CP value is higher than the summer 2CP value<sup>230</sup>.

However, Manitoba Hydro has noted that summer loadings also drive transmission investment<sup>231</sup>. Also, when considering this issue it is important to note that the PUB’s original decision to adopt the 2CP approach was made at the time of the 2002 Status

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<sup>224</sup> May Workshop, page 415

<sup>225</sup> Coalition/MH I-66 a)

<sup>226</sup> Coalition/MH I-66 c)

<sup>227</sup> MIPUG/MH I-7 f)

<sup>228</sup> May Workshop, page 149

<sup>229</sup> May Workshop, page 446

<sup>230</sup> May Workshop, page 408

<sup>231</sup> May Workshop, pages 409-410

Update<sup>232</sup>, before the PUB approved the adoption of an export class. The formal inclusion of any dependable export class would serve to strengthen the rationale that led the PUB to adopting the 2 CP approach at that time. **Continued use of a 2CP allocator for Tariffable Transmission costs is appropriate.**

The final issue of concern regarding the classification/allocation of Tariffable and Non-Tariffable Transmission costs is the inclusion of the dependable export class in the allocation of the Non-Tariffable portion. **Non-Tariffable costs are, by definition, the costs of assets that are not used/useful for purposes of exports<sup>233</sup>. As a result, these costs should only be allocated to the domestic customer classes using the 2CP allocation factor<sup>234</sup>.** During the May Workshop Manitoba Hydro agreed that excluding exports from the allocation should be considered<sup>235</sup>.

Data<sup>236</sup> provided by Manitoba Hydro indicates that there is a material difference between the hours that contribute to the top 50 when measured at Generation (used for purposes of determining CP factors for total load including exports) as opposed to those when measured at the Common Bus (used for purposes of determining CP factors for domestic load) suggesting that the change in allocation factor could also impact the relative allocation of costs to customer classes. The following table sets out the impact on the COSS results of allocating Non-Tariffable Transmission just to the Domestic classes.

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<sup>232</sup> Order 7/03, page 101

<sup>233</sup> May Workshop, page 453

<sup>234</sup> This allocation factor will be based on different loads than that used to determine the 2CP allocation factor for Tariffable Transmission – see MIPUG/MH I-3 b).

<sup>235</sup> May Workshop, page 454

<sup>236</sup> Undertaking, Transcript page 602

<b>TABLE #14 - ALLOCATION OF NON-TARIFFABLE TRANSMISSION TO JUST DOMESTIC CLASSES</b>											
Customer Class	Corrected PCOSS14-Amended					Impact of Allocating Non-Tariffable Transmission to Domestic Classes					
	Total Cost	Class	Net Export	Total	RCC %	Total Cost	Class	Net Export	Total	RCC %	RCC
	(\$000)	Revenue	Revenue	Revenue	Current	(\$000)	Revenue	Revenue	Revenue	Current	Change
					Rates					Rates	
Residential	626,705	588,630	38,166	626,795	100.00%	628,486	588,630	40,150	628,780	100.00%	0.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,830	135,035	8,249	143,284	107.90%	0.00%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,799	136,080	8,608	144,688	104.20%	-0.10%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	200,717	186,797	12,544	199,341	99.30%	0.00%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	100,088	84,956	6,240	91,196	91.10%	0.00%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,755	57,808	3,915	61,723	99.90%	-0.10%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	205,755	189,258	12,918	202,176	98.30%	0.00%
SEP	968	826	-	826	85.40%	968	826	-	826	85.40%	0.00%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	21,981	21,630	429	22,059	100.40%	0.10%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,491,378	1,401,019	93,053	1,494,072	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	642	7,254	72.90%	0.30%
Export	256,200	345,233	-	256,200	100.00%	251,538	345,233	-	251,538	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%

\*Includes Curtailment Customers

In the case of the Interconnections sub-function, the facilities were built<sup>237</sup> and are currently used both for exports and for supporting domestic load. With respect to the latter, interconnections allow for: i) the sharing of generation contingency reserves; ii) sharing of capacity resources through diversity agreements; and iii) the importation of energy during drought conditions or extreme loss of supply<sup>238</sup>.

Indeed, for planning purposes, imports form part of Manitoba Hydro's dependable capacity and energy supply<sup>239</sup>. **As result, Manitoba Hydro's proposal to allocate the cost Interconnections to both domestic load and exports is reasonable.**

**Furthermore, Manitoba Hydro's proposal to only include Dependable Exports in the allocation is consistent with the rationale and approach used for Generation.**

The classification of Interconnections as energy-related and the subsequent allocation based on weighted energy is a departure from the currently approved approach<sup>240</sup>.

Manitoba Hydro explains that this change is to recognize that the role of US interconnections is to move energy both to and from the province and that using a weighted energy allocator places a heavier emphasis on the energy being more of a cost driver than demand<sup>241</sup>.

<sup>237</sup> PUB/MH I-61 a) – b)

<sup>238</sup> Appendix 1, pages 6-7

<sup>239</sup> 2016/17 Supplemental Filing, Attachment 17

<sup>240</sup> Under the current approved approach there is no separation of Interconnections and they are classified/allocated using 2CP – the same as other Transmission costs.

<sup>241</sup> May Workshop, page 385 and Appendix 1, page 6

The role of energy as a cost driver with respect to Interconnections can be seen in the fact that Manitoba Hydro's energy reliability criterion<sup>242</sup> relies on imports and import capability (i.e., imports can be used to meet dependable energy requirements based on the lesser of i) 10% of Manitoba load plus exports, or ii) the off-peak energy import capability, with the limiting factor is the off-peak energy import capability<sup>243</sup>).

Similarly, it can be seen in the increased energy reliability benefits ascribed to the Great Northern Transmission Line ("GNTL") project<sup>244</sup>. It can also be seen in the nature of Manitoba Hydro's export contracts which typically provide for capacity and energy during either the 5x16 or 7x16 hours<sup>245</sup>. **Based on these observations Manitoba Hydro's proposal to classify Interconnections as energy-related and use a weighted energy allocator (which reflects both energy and capacity considerations) is reasonable.**

## 4.7 Sub-Transmission Function: Definition, Classification and Allocation

### 4.7.1 Manitoba Hydro Proposal

#### *Definition*

Manitoba Hydro defines<sup>246</sup> Sub-Transmission as including transmission lines operating at 33 and 66 kV as well as the low voltage portion of substations stepping down to sub-transmission voltages and the high voltage portion of substations that step power down from sub-transmission to distribution voltages<sup>247</sup>. Also included is a portion of the costs associated with communication facilities, administration buildings, and general equipment as discussed in Section 4.3.1.

#### *Classification/Allocation*

Sub-Transmission costs are classified as demand-related and allocated to domestic customer classes served at less than 100 kV using a 1 NCP allocator<sup>248</sup>.

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<sup>242</sup> NFAT, CAC/MH I-049

<sup>243</sup> NFAT, CAC/MH I-057

<sup>244</sup> May Workshop, page 463

<sup>245</sup> Coalition/MH I-22 b)

<sup>246</sup> Submission, page 9

<sup>247</sup> Coalition/MH I-34

<sup>248</sup> Appendix 2.1, Schedules E1 and E6. Also, Manitoba Hydro's May Workshop presentation, slide 59.

#### 4.7.2 ECS Comments

##### *Definition*

Manitoba Hydro's separation of Sub-Transmission facilities recognizes that they are used solely to serve domestic load. In this role they are similar to Non-Tariffable Transmission except that the facilities are not used to serve domestic customers with delivery voltages greater than 100 kV. **Overall, Manitoba Hydro's use and definition of a Sub-Transmission function is consistent with industry norms<sup>249</sup>.**

It is noted that for purposes of the COSS costs that in Manitoba Hydro's financial systems are reported as Sub-Transmission are subsequently re-assigned to the Transmission and Distribution functions<sup>250</sup>. When asked what the basis was for this re-functionalization in PCOSS14-Amended Schedules C6 and C12, Manitoba Hydro explained<sup>251</sup>:

*The schedules include a row which is titled "Common Subtransmission Costs", but which also includes SCC's for Common Subtransmission and Distribution costs related to system planning. These costs are prorated between Subtransmission and Distribution on the basis of relative operating cost of each function in Schedule C12, and depreciation in Schedule C6.*

However, the Schedules do not actually show any re-assignment of Common Subtransmission costs and the amounts re-assigned exceed the total reported Common Subtransmission costs. **Such re-assignments would be more transparent and readily understood if formally incorporated in the COSS model.**

##### *Classification/Allocation*

**The classification of Sub-Transmission as demand-related and the use of a 1NCP allocation factor are also consistent with industry norms<sup>252</sup>.**

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<sup>249</sup> The NARUC Cost Allocation Manual (page 73) notes that facilities operating at voltages of 115 kV or higher are considered Transmission while facilities operating at voltages below 25 kV are general considered Distribution and that facilities operating at voltages in between are now commonly referred to as sub-transmission facilities.

<sup>250</sup> See Appendix 3.1, Schedule C6 and C12

<sup>251</sup> Undertaking #25

<sup>252</sup> Appendix 5, page 16

## 4.8 Distribution Plant Function: Definition, Classification and Allocation

### 4.8.1 Manitoba Hydro Proposal

#### *Definition*

All facilities operating at voltages less than 30 kV are functionalized as Distribution Plant as are the meters used for billing purposes and the low side of substations stepping power down from >30 kV to distribution voltages<sup>253</sup>.

The Distribution Plant function is sub-functionalized into the following<sup>254</sup>:

- Substations
- Line Transformers
- Pole, Wire and Related Facilities
- Meters and Metering Transformers
- Meter Maintenance
- Services

#### *Classification/Allocation*

The following table sets out the classification and allocation for each of the Distribution Plant sub-functions.

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<sup>253</sup> Submission, page 9

<sup>254</sup> Appendix 3.1, pages 27 and 64

**Table #15 - Distribution Plant Classification and Allocation**

<b>Sub-Function</b>	<b>Classification<sup>1</sup></b>	<b>Allocation<sup>2</sup></b>
Substations	100% Demand	1NCP – for those classes served at <30 kV (D32)
Line Transformers	100% Demand	1NCP – for those classes served at <30 kV and using utility transformer (D40)
Poles, Wire and Related Facilities	60% Demand/40% Customer	Demand – 1NCP for those classes served at <30kV with adjustment for those only using primary lines (D36)  Customer – Weighted Customer count for those classes served at <30kV with adjustment for those only using primary lines and also for Sentinel, Flat Rate Water Heating and Street Lighting (C23)
Meters and Metering Transformers	100% Customer	Weighted Customer count excluding Sentinel, Flat Rate Water Heating and Street Lighting (C40)
Meter Maintenance	100% Customer	Weighted Customer count excluding Sentinel, Flat Rate Water Heating and Street Lighting (C41)
Services	100% Customer	Weighted Customer count served at <30 kV excluding Sentinel, Flat Rate Water Heating and Street Lighting (C27)
Notes: 1) Appendix 3.1, page 27 and page 64 2) Allocation factors are described in Appendix 3.1, pages 71-73 and 80-83		

#### 4.8.2 ECS Comments

##### *Definition*

**Both Manitoba Hydro's definition of Distribution Plant and its proposed sub-functions are similar to those used elsewhere.** The one issue is that Manitoba Hydro has not distinguished between primary and secondary distribution facilities but

rather chosen to reflect the fact that some customers only require primary facilities in the allocation factors used for Distribution Poles and Wires<sup>255</sup>.

**Since the adjustment to the allocation factors is based on Manitoba Hydro's estimate that costs for Distribution Poles and Wires are split 70/30 between primary and secondary there is no reason why this cost split could not have been applied to the total costs of these facilities in order to sub-functionalize them into Primary and Secondary sub-functions.** Manitoba Hydro acknowledges that to do so would slightly change the allocation of costs to customer classes<sup>256</sup>. Also, separating the costs between primary and secondary would eliminate a number of the adjustments that are now required to the allocation factors.

A related issue is the fact that the 70/30 split is based on an assessment undertaken 25 years ago in 1991<sup>257</sup>. It is likely that Manitoba Hydro's distribution system has changed materially since then particularly given the subsequent acquisition of Winnipeg Hydro. **It would be prudent for Manitoba Hydro to investigate ways of updating this percentage split used for primary/secondary costs.**

The SCC data available from Manitoba Hydro's financial systems regarding Distribution Poles & Wires, Distribution Transformers, and Meter Investment and Maintenance is sufficiently detailed to facilitate sub-functionalization<sup>258</sup>. However, the Distribution Plant function also includes common Distribution costs tracked at the cost center level related to Research and Development, Planning & Records, Environmental and Hazardous Waste which are all included in the Distribution Substation sub-function<sup>259</sup>. Manitoba Hydro has indicated that this treatment was chosen for simplicity as opposed to being reflective of the nature of the costs involved<sup>260</sup>.

The operating and depreciation costs for that share of Communication plant that was been functionalized as Distribution in the COSS have also been assigned to the

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<sup>255</sup> Appendix 4, page 11

<sup>256</sup> Coalition/MH I-71 c)

<sup>257</sup> PUB/MH I-49

<sup>258</sup> Coalition/MH I-49

<sup>259</sup> Coalition/MH I-49 a)

<sup>260</sup> May Workshop, page 838



Stations sub-function<sup>261</sup>. However, the assets associated with Communications, Building and General Equipment that were pro-rated to the Distribution Plant function have all been sub-functionalized as Poles and Wires<sup>262</sup> which means the related Interest costs will be also.

**Manitoba Hydro agrees that there should be a consistent treatment of Interest, Operating and Depreciation costs but currently does not have any views as to what it should be<sup>263</sup>. At some point in the future, Manitoba Hydro should re-assess the sub-functionalization of these costs.**

### *Classification*

The only major issue with respect to Manitoba Hydro's classification of Distribution Plant is with respect to the demand/customer splits proposed for the Poles & Wires and Transformers sub-functions. In both cases Manitoba Hydro proposes to continue to use the existing split noting that the percentages used are in line with industry practice<sup>264</sup>.

However, the existing demand/customer splits are based on a study undertaken in 1990<sup>265</sup> which itself did not undertake an analysis of Manitoba Hydro's distribution costs but rather relied on general industry practice. Furthermore, in the case of Poles and Wires, the study noted<sup>266</sup> that industry practice ranged from demand classifications as low as 30% and as high as 100%. More recent surveys have indicated similarly wide range for the industry practice as it relates to distribution lines and distribution transformers<sup>267</sup>.

As a result, industry practice provides little guidance (or broad license) regarding the appropriate demand/customer split. **Manitoba Hydro has acknowledged the need to update the split for poles & wires and transformers as between demand and customer-related and should be encouraged to do so.**

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<sup>261</sup> Coalition/MH I-49 a) and May Workshop. page

<sup>262</sup> PCOSS14-Amended COSS Model, Interest Summary Tab, Line 24

<sup>263</sup> May Workshop, page 840-841

<sup>264</sup> Coalition/MH I-69 a)

<sup>265</sup> A copy was provided in the 205 COSS Review, PUB/MH I-29

<sup>266</sup> Page IV-5

<sup>267</sup> A 2013 survey done by Elenchus Research Associates for SaskPower found the demand-related range for Lines to be 35%-100%.

**With respect to the other sub-functions, industry practice is more standardized with Substations generally being classified as demand-related while Service and Meters are classified as customer-related – consistent with Manitoba Hydro’s proposals.**

#### *Allocation*

**The demand and customer allocation factors proposed by Manitoba Hydro (i.e. 1NCP in the case of demand-related costs and some form of customer/weighted customer count allocator in the case of customer-related costs) are also consistent with industry practice and generally appropriate.** However, there are issues with the specific derivation of some of the allocators.

One set of issues arises from the fact that 103,000 of the Residential customers are in multi-residential buildings (e.g. apartment buildings) which also have 4,900 meters that are billed as GS customers. Manitoba Hydro has confirmed that these GS meters are associated with either GSS or GSM customers<sup>268</sup>. This has a number of implications for the COSS including:

- The service drops assumed for Residential, GSS and GSM should all be reduced as the current COSS treats the 107,900 customers each as a separate service when there really only 4,900 in total<sup>269</sup>. One approach<sup>270</sup> would to prorate the 103,000 over the three classes according to the total number of customers in each class. The following table sets out the resulting reduction in customer count by class.

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<sup>268</sup> May Workshop, page 870

<sup>269</sup> May Workshop, pages 869-870

<sup>270</sup> There are other approaches but this one fairly distributes the benefit of the reduced connections across all three classes.

TABLE #16					
<b>CUSTOMER REDUCTION DUE TO DOUBLE COUNTING OF APARTMENTS</b>					
	<b>Customer Class</b>	<b>Customer Count</b>	<b>%</b>	<b>Reduction</b>	
	Residential	462,217	87.34%	89,959	
	GSS	65,031	12.29%	12,657	
	GSM	1,974	0.37%	384	
	Total	529,222	100%	103,000	
Source: Appendix 3.1, Schedule D5					

- The customer counts used in the allocation of the customer portion Poles & Wires sub-function would also need to be similarly reduced.

**The customer counts used in the allocation of Services and Poles & Wires to customer classes should be adjusted to remove the double counting that currently exists regarding Apartments.** The following table sets out the impact on the COSS results of making these reductions to the customer counts used in the allocation of Poles & Wires and Services.

TABLE #17 - ELIMINATION OF DOUBLE COUNTING OF APARTMENTS											
Customer Class	Corrected PCOSS14-Amended					Impact Eliminating Apartment Double Counting					
	Total Cost	Class Revenue	Net Export Revenue	Total Revenue	RCC %	Total Cost	Class Revenue	Net Export Revenue	Total Revenue	RCC %	RCC Change
	(\$000)	(\$000)	(\$000)	(\$000)	Rates	(\$000)	(\$000)	(\$000)	(\$000)	Rates	
Residential	626,705	588,630	38,166	626,795	100.00%	626,609	588,630	38,160	626,789	100.00%	0.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,399	135,035	7,837	142,872	107.90%	0.00%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,330	136,080	8,177	144,257	104.30%	0.00%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	200,024	186,797	11,915	198,712	99.30%	0.00%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	99,740	84,956	5,927	90,883	91.10%	0.00%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,534	57,808	3,719	61,526	100.00%	0.00%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	204,982	189,258	12,267	201,525	98.30%	0.00%
SEP	968	826	-	826	85.40%	969	826	-	826	85.30%	-0.10%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	22,130	21,630	418	22,048	99.60%	-0.70%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,486,716	1,401,019	88,421	1,489,440	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	612	7,224	72.60%	0.00%
Export	256,200	345,233	-	256,200	100.00%	256,200	345,233	-	256,200	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%

\*Includes Curtailment Customers

A second issue pertains to the allocation of Poles and Wires and the treatment of those customer classes that are viewed as not making use of the facilities operating at secondary voltages. In the case of Area and Roadway Lighting (A&RL), the class is not allocated the customer costs for the secondary system in recognition of the fact that for

some Street Lighting configurations the secondary facilities are included in the assets direct assigned to the class<sup>271</sup>. Furthermore, the adjustment made accounts for the fact that the demand/customer split for primary distribution facilities is presumed to be different than that for secondary facilities.

This results in the application of adjustment factor of 58% to the customer count used for Street Lights. It should be noted that if no recognition had been given to the different demand/customer split for primary the adjustment factor would have been 70% and the customer costs allocated higher.

Similarly, an adjustment is made to both the customer count and demand for the GSL<30 class to account for the fact that these customers own their own transformers and do not use secondary facilities at all.

However, in this case, no recognition is given to the fact that the demand/customer split for primary facilities is different than that for secondary facilities and the same 70% adjustment factor is applied to both the customer count and 1NCP allocator. Manitoba Hydro has acknowledged that similar recognition may be appropriate in the case of the GSL<30 class but has not assessed how the adjustment would be made<sup>272</sup>. **There is no obvious reason why a similar recognition and related adjustment should not be made for the GSL<30 class. If such recognition was made then the adjustment factors for demand and customer would be 77% and 58% respectively<sup>273</sup>.** The following table sets out the impact on the COS results of implementing this change.

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<sup>271</sup> Coalition/MH I-73 c)

<sup>272</sup> May Workshop, pages 845-846

<sup>273</sup> The 58% for customer-related costs is calculated on the same basis as was done for AR&L. In the case of demand-related costs, applying the same formula as is used for customer-related cost but plugging in the demand-related percentages for primary and secondary results in  $(70\% \times 70\%) / ((70\% \times 70\%) + (50\% \times 30\%)) = 77\%$

TABLE #18 - CORRECTION OF THE GSL<30 ADJUSTMENT FACTOR											
Customer Class	Corrected PCOSS14-Amended					Impact of Correcting the GSL<30 Adjustment Factor					
	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	RCC Change
Residential	626,705	588,630	38,166	626,795	100.00%	626,468	588,630	38,151	626,781	100.00%	0.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	132,407	135,035	7,838	142,873	107.90%	0.00%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	138,300	136,080	8,175	144,255	104.30%	0.00%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	199,958	186,797	11,911	198,708	99.40%	0.10%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	100,134	84,956	5,951	90,908	90.80%	-0.30%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	61,534	57,808	3,719	61,526	100.00%	0.00%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	204,982	189,258	12,267	201,525	98.30%	0.00%
SEP	968	826	-	826	85.40%	968	826	-	826	85.40%	0.00%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	21,966	21,630	408	22,038	100.30%	0.00%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,486,716	1,401,019	88,421	1,489,440	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	612	7,224	72.60%	0.00%
Export	256,200	345,233	- 89,033	256,200	100.00%	256,200	345,233	- 89,033	256,200	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,864	1,752,864	-	1,752,864	100.00%	0.00%
*Includes Curtailment Customers											

Finally, Manitoba Hydro acknowledges that the weights applied to the customer counts for purposes of allocating meter investment, meter maintenance and services investment have not been reviewed for 25 years. **Manitoba Hydro does not expect that revised weights would have a material impact on the COSS results but recognizes that they should be updated<sup>274</sup> and should be encouraged to do so.**

## 4.9 Distribution (Customer) Service Function: Definition, Classification and Allocation

### 4.9.1 Manitoba Hydro Proposal

#### Definition

The Distribution Service function captures the costs associated with those services provided to customers after the electricity has been delivered. The function also includes a share of the cost for administration buildings and general equipment.<sup>275</sup> The costs are sub-functionalized as follows to recognize that all customers do not require/use these service to the same degree<sup>276</sup>:

- Customer Service – General
- Customer Accounting – Billing
- Customer Accounting – Collections
- Marketing – R&D

<sup>274</sup> PUB/MH I-57 and 58

<sup>275</sup> Appendix 3.1, page 23

<sup>276</sup> Appendix 3.1, page 64

- Inspection
- Meter Reading

### *Classification/Allocation*

Manitoba Hydro classifies all six sub-functions as customer-related and, in each case, uses a weighted customer count to allocate the cost to customer classes, where for each sub-function the customer class weights reflect the relative cost per customer incurred to provide the service<sup>277</sup>.

### 4.9.2 ECS Comments

#### *Definition*

Manitoba Hydro's six Distribution – Services sub-functions capture the major activities that take place after electricity is delivered. Furthermore, as discussed below, the allocation factor for Customer Service – General (which is the largest of the six sub-functions in terms of costs) takes into account the extent to which different customer classes use the associated activities<sup>278</sup>.

The SCC detail in Manitoba Hydro's financial systems is sufficient to allow the operating and depreciation costs assigned to Distribution Services to be sub-functionalized. The interest costs allocated to Distribution Services are sub-functionalized based on the relative Operating costs assigned to each sub-function<sup>279</sup>. The Interest costs attributed to the Distribution Service function's share of Buildings and General Equipment are also sub-functionalized based on the relative Operating costs assigned to each sub-function<sup>280</sup>. **Overall, Manitoba Hydro's definition and functionalization of Distribution Services is reasonable.**

#### *Classification and Allocation*

Manitoba Hydro's general approach to classifying and allocating Distribution Services costs is consistent with industry practice and reasonable. However, there are issues with some of specific allocators used.

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<sup>277</sup> Appendix 3.1, pages 74-79

<sup>278</sup> MIPUG/MH I-4

<sup>279</sup> Coalition/MH I-51

<sup>280</sup> PCOSS14-Amended Model,

As noted above the customer class weighting factors for Customer Service – General consider the use by customer class of each of the associated departments<sup>281</sup>. The weighting factors used reflect both the direct labour costs and overheads for each department and their usage by customer class<sup>282</sup> and were last updated for PCOSS11<sup>283</sup>.

**While there is likely some effort involved in updating the customer class weights for each department, there is no reason why the current weights should not applied to the forecast budgets for 2013/14 as set out in MIPUG/MH I-4 b).** However, for PCOSS14-Amended making this change has minimal impact on the allocation of Customer Service – General costs to customer class indicated in the following table.

<b>TABLE #19 - CUSTOMER SERVICE GENERAL ALLOCATION FACTORS</b>									
				<u>PCOSS14- Amended</u>		<u>Revised Allocation Factors</u>			
	Res			44.5%			44.1%		
	GSS			22.8%			22.8%		
	GSM			13.2%			13.2%		
	GSL 0-30			7.6%			7.5%		
	GSL 30-100			4.1%			4.1%		
	GSL 30-100 Curtailable			1.4%			1.4%		
	GSL 100+			3.8%			3.9%		
	GSL 100+ Curtailable			1.4%			1.5%		
	SEP			0.6%			0.8%		
	Lighting			0.6%			0.8%		
	Source:	PCOSS14-Amended from MIPUG/MH I-4 b)							

A second issue is with respect to the customer class weights used for Meter Reading. Manitoba Hydro has acknowledged that the weights simply reflect the frequency of meter reading and do not take into account the fact that different types of meters will have different meter reading costs<sup>284</sup>. However, it notes that incorporating such a refinement would likely have a minimal effect on the overall results of the COSS. **This**

<sup>281</sup> MIPUG/MH I-4

<sup>282</sup> Undertaking #17

<sup>283</sup> PUB/MH I-57

<sup>284</sup> May Workshop, pages 847-848

**may be the case but, if relative costs of meter reading are readily available and the improvement can be made with minimal effort there is no reason why Manitoba Hydro should not undertake to revise its COS methodology accordingly.**

Finally, **Manitoba Hydro has acknowledged that some of the customer weighting factors are based on analysis done 25 years ago (e.g. Billing and Collections factors are based on 1991 analysis) and need to be updated<sup>285</sup>. Manitoba Hydro should be encouraged to pursue such updates.**

#### **4.10 Net Export Revenue Allocation**

##### **4.10.1 Manitoba Hydro Proposal**

Net export revenues are calculated by subtracting from gross export revenues the costs that are either directly assigned or allocated to exports<sup>286</sup>. Net export revenues are allocated to customer classes based on the total costs allocated to each customer class excluding the costs of dedicated or end-use facilities that are directly assigned to customer classes, namely the costs related to DSM and Area & Roadway Lighting<sup>287</sup>. The allocation includes the Diesel class and costs directly assigned to Diesel per the tentative Settlement Agreement between Manitoba Hydro, MKO and AANCC<sup>288</sup>. For purposes of calculating the revenue to cost ratios, allocated net export revenues are added to the customer revenues for the class<sup>289</sup>.

Apart from the changes arising due to the Settlement Agreement, the approach is generally consistent with that approved by the PUB in Order 117/06<sup>290</sup>.

##### **4.10.2 ECS Comments**

The Board's decision in 2006 to alter treatment of export revenues (i.e., create an export class, allocate this export class a share of embedded costs and the allocation base for net export revenues) was based on a number of factors:

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<sup>285</sup> PUB/MH I-57

<sup>286</sup> Appendix 3, pages 3-4

<sup>287</sup> Coalition/MH I-76 b)

<sup>288</sup> Coalition/MH I-76 f)

<sup>289</sup> Appendix 3, Schedule B1-Amended

<sup>290</sup> Page 76



- As a result of both the volumes involved and the level of export prices, export revenues comprised a significant portion of Manitoba Hydro's revenues. Net export revenues (particularly when based on gross revenues less variable costs) had a significant impact on the COSS results and the impacts varied widely by customer class<sup>291</sup>.
- The rates for some customer classes were less than export prices such that increases in load for these classes led to counter-intuitive results which were aggravated when net export revenues were allocated strictly based on the Generation and Transmission costs associated with the customer classes<sup>292</sup>. Put another way, allocating net export revenue to customers on the same basis as Generation and Transmission costs suggested that it's a domestic customer's use of such facilities that gives rise to the benefits created by export sales. However, in reality the opposite is true, as increased domestic load would lead to reduced export sales and increased costs (and rates) overall.

Export prices have softened in recent years. However, as discussed in Section 4.2.2, export revenue still represents a significant portion of Manitoba Hydro's overall revenue and this proportion is expected to increase in the future. Similarly, while the differences between export prices and domestic prices are not as pronounced, there are still issues and these issues will become more pronounced in the future<sup>293</sup>.

**Overall, given that the proposed methodology already allocates a portion of fixed Generation and Transmission costs to exports, the allocation of the resulting net export revenues on a more neutral basis (i.e. one that results in less distortion in the pre vs. post net export revenue allocation revenue to cost ratios) is reasonable and reduces the future potential for re-creating the cost of service results and perverse cost causation signals that were of concern to the Board in its 2006 Order.**

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<sup>291</sup> 2005 COSS Review, ECS Evidence, Table 12

<sup>292</sup> 2005 COSS Review, PUB/MH I-26

<sup>293</sup> May Workshop, page 287

## **5. SUMMARY AND CONCLUSIONS**

The comments in the preceding sections identified a number of principles that should be considered in establishing Manitoba Hydro's cost of service methodology along with a number of changes that should be made to Manitoba Hydro Cost of Service Study in terms of: i) methodology; ii) input corrections, iii) data input improvements and iv) improvements to the model itself.

### **5.1 COSS Principles**

Cost of service studies are a key part of the overall rate making process and their main purpose is to assist in determining a fair apportionment of a utility's revenue requirement among its customer classes. To this end, cost causation is the primary consideration in establishing cost of service methodologies.

However, cost causation is not the only consideration. The determination of an appropriate cost of service methodology must also consider the other overarching rate objectives of rate making including encouraging efficient use of electricity, rate stability, understandability and feasibility in application.

In terms of cost causation, while it is useful to consider the original intent/driver behind an investment more weight should generally be given to the current role that investments play in meeting customer service requirements. Furthermore, when considering the current role of a utility's investments and operating activities play in meeting customers' service requirements it is important to consider the full range of likely operating conditions and not just those that underpin the test year's revenue requirement.

## 5.2 COSS Methodology

A number of the changes that Manitoba Hydro has proposed to the currently approved methodology are reasonable and appropriate, including:

### *Exports*

- The establishment of two export classes where the dependable export class would attract embedded costs in the same manner as firm domestic load while the opportunity class would attract only variable costs. (pages 29 and 31)
- Distinguishing between dependable and opportunity exports based on the forecast average (five years) dependable energy surplus to domestic needs versus the average energy available in excess of dependable energy. (page 32)

### *Generation*

- The inclusion of the Dorsey (and future Riel) converter facilities in Generation as opposed to Transmission. (page 53)
- The inclusion of purchases (including wind), trading desk costs, thermal fuel and all thermal plant costs in the Generation pool for allocation to both domestic load and dependable exports. (pages 54-55 and 57)

### *Transmission*

- The sub-functionalization of Interconnection costs and their allocation to domestic customers and dependable exports using the weighted energy allocator. (pages 68 and 72-73)
- The creation of a Non-Tariffable Transmission sub-function to capture those Transmission costs that are not deemed to be tariffable for purposes of the OATT. (page 68)

### *Net Export Revenues*

- The allocation of Net Export Revenues to domestic customer classes based on the total costs allocated to each class, excluding direct assignments<sup>294</sup>. (page 86)

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<sup>294</sup> Note. While this is not a change from the current approved methodology, it is a relatively recent change to the methodology.

However, the preceding sections did identify and recommended a number of changes to Manitoba Hydro's proposed COS methodology:

*Revenue and Direct Assignment*

- a) The assignment of the revenues from Late Payment and Customer Adjustments should be based on the proportion of late payment charge revenues received (historically) from each customer class. (page 37)
- b) Clarification is required as to the intent of the Diesel Settlement Agreement with respect to the treatment of 3<sup>rd</sup> party contributions in the COSS. However, this will have to await the filing of the finalized Settlement Agreement. (page 42)
- c) DSM costs should be assigned directly to the Generation, Transmission and Distribution-Plant functions based on the relative values of the DSM program savings in each area. (page 45)
- d) NEB fees should be allocated to all customer classes (including Opportunity exports). (page 48)

*Generation*

- e) The inclusion of an explicit capacity adder in the calculation of the weighted energy allocator for Generation costs has not been sufficiently justified at this time and requires further consideration in terms of: i) whether or not one is needed, ii) what the value should be; iii) what hours/seasons it should be incorporated in; and iv) for what historical years should it be added. (page 64)

*Transmission*

- e) The allocation of the costs in the Non-Tariffable Transmission sub-function should not include exports. (page 71)

*Distribution - Plant*

- f) The sub-functionalization of "common" costs such as Buildings, Communication, General Equipment and certain SCCs needs to be re-assessed. (page 78)
- g) In the Distribution-Plant function, the COSS methodology should separate out the costs of primary and secondary facilities into two distinct sub-functions. (page 77)

- h) The allocation base for the customer portion of the Services and Poles & Wires sub-functions needs to be adjusted in order to account for the fact that 103,000 Residential customers are in Apartments that are “served” as GSS or GSM customers. (page 80)
- i) The GSM portion of the allocation base used for Poles & Wires needs to be adjusted to account for the different demand/customer classification for primary as opposed to secondary facilities – similar to that done for A&RL. (page 81)

#### *Distribution – Services*

- j) The customer weighting factors for Customer Service – General should be derived by applying the customer weighting factors established for each Department to the Department’s budget for the test year. (page 84)

### **5.3 Required Input Corrections**

Required input corrections include:

- Not all AC lines that serve to link generation to the transmission system have been removed from the Non-Tariffable Transmission sub-function and included in Generation. (page 69)
- Manitoba Hydro has noted that specific revisions/corrections are required to the customer counts used in allocating Meter Assets, Meter Maintenance and Meter Reading costs. (page 39)
- The Operating costs by function used to assign the cost associated with Buildings, Communication & Control and General Equipment to functions need to be revised. (page 39)
- The corrections that Manitoba Hydro has made to the weights that are to be applied to the energy use by customer classes in each of the 12 SEP periods for purposes of allocating Generation costs. (page 39)

### **5.4 Areas for Data Input Improvement**

Areas for data input improvements include:

- The basis for the allocation factors used to assign system control costs to functions was established in 1997 and should be updated. (page 36)
- The current demand/customer classification of distribution lines and transformers was established roughly 25 years ago and should be updated (page 78)
- The weights applied to the customer counts for the purposes of allocating meter investment, meter maintenance and services investment have not been reviewed in 25 years and should be updated. (page 82)
- The customer weightings used for meter reading should be revised so as to account for the relative effort in reading different types of meters as well as the frequency of meter reading. (page 85)
- The customer weighting factors used for Billing and Collections are based on analysis done 25 years ago and need to be updated. (page 85)

## 5.5 Potential COS Model Improvements

Possible model improvements include:

- The functionalization of Operating and Depreciation costs associated with Communications and Control Systems should be incorporated in the COSS model so that it can reflect any re-functionalization of assets/activities that occurs as part of the COS. (page 36)
- The functionalization of Other Revenues should also be incorporated in the COSS model so that it can reflect any re-functionalization of assets/activities that occurs as part of the COS. (page 37)
- The COSS model should be refined so as to allow for the sub-functionalization of: i) the costs associated with Settlement Cost Centres that are associate with common activities and ii) the shares of Regulated Assets, Buildings, Communication & Control and General Equipment costs that are assigned to each function. Such a refinement would also permit the COSS model to re-functionalize these costs when assets/activities are re-assigned between functions as part of the COSS. (pages 69 and 74)

## 5.6 Impact of Recommended Methodology Changes

Adopting the recommended COSS methodology changes<sup>295</sup> noted above would change the COSS results as follows:

TABLE #20 - IMPACT OF RECOMMENDED COSS METHODOLOGY CHANGES											
Customer Class	Corrected PCOSS14-Amended					Impact of Recommended COSS Methodology Changes					
	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	Total Cost (\$000)	Class Revenue (\$000)	Net Export Revenue (\$000)	Total Revenue (\$000)	RCC % Current Rates	RCC Change
Residential	626,705	588,630	38,166	626,795	100.00%	634,723	590,388	38,111	628,499	99.00%	-1.00%
General Service - Small Non Demand	132,450	135,035	7,841	142,875	107.90%	130,001	134,614	7,806	142,420	109.60%	1.70%
General Service - Small Demand	138,349	136,080	8,178	144,258	104.30%	136,325	135,656	8,185	143,842	105.50%	1.20%
General Service - Medium	200,027	186,797	11,916	198,713	99.30%	198,685	186,215	11,930	198,145	99.70%	0.40%
General Service - Large 0 - 30kV	99,732	84,956	5,927	90,883	91.10%	99,149	84,692	5,953	90,645	91.40%	0.30%
General Service - Large 30-100kV*	61,534	57,808	3,719	61,526	100.00%	62,092	57,808	3,765	61,572	99.20%	-0.80%
General Service - Large >100kV*	204,982	189,258	12,267	201,525	98.30%	202,482	189,258	12,468	201,725	99.60%	1.30%
SEP	968	826	-	826	85.40%	1,029	824	-	824	80.10%	-5.30%
Area & Roadway Lighting	21,969	21,630	409	22,038	100.30%	22,499	21,620	431	22,051	98.00%	-2.30%
Total General Consumers	1,486,716	1,401,019	88,421	1,489,440	100.20%	1,486,985	1,401,075	88,649	1,489,723	100.20%	0.00%
Diesel	9,948	6,612	612	7,224	72.60%	9,948	6,612	597	7,209	72.50%	-0.10%
Export	256,200	345,233	- 89,033	256,200	100.00%	255,987	345,233	- 89,246	255,987	100.00%	0.00%
Total System	1,752,864	1,752,864	-	1,752,864	100.00%	1,752,920	1,752,920	-	1,752,920	100.00%	0.00%

\*Includes Curtailment Customers

<sup>295</sup> Due to modelling and time constraints, recommended changes (f) and (g) are not incorporated in the table.

## **APPENDIX A**

### **CV FOR ECS CONSULTANT**



## ECONALYSIS CONSULTING SERVICES

### **William O. Harper**

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Mr. Harper has over 35 years experience in the design of rates and the regulation of electricity utilities. While employed by Ontario Hydro, he has testified as an expert witness on rates before the Ontario Energy Board from 1988 to 1995, and before the Ontario Environmental Assessment Board. He was responsible for the regulatory policy framework for Ontario municipal electric utilities and for the regulatory review of utility submissions from 1989 to 1995. Mr. Harper also coordinated the participation of Ontario Hydro (and its successor company Ontario Hydro Services Company) in major public reviews involving Committees of the Ontario Legislature, the Ontario Energy Board and the Macdonald Committee. He has served as a speaker on rate and regulatory issues for seminars sponsored by the APPA, MEA, EPRI, CEA, AMPCO and the Society of Management Accountants of Ontario. Since joining ECS, Mr. Harper has provided consulting support for client interventions on energy and telecommunications issues before the Ontario Energy Board, Manitoba Public Utilities Board, Québec's Régie de l'énergie, British Columbia Utilities Commission, Saskatchewan Rate Review Panel and CRTC. He has also appeared before the Manitoba's Public Utilities Board, the Manitoba Clean Environment Commission, the Ontario Energy Board and Quebec's Régie de l'énergie.

### **EXPERIENCE**

**Econalysis Consulting Services – Associate**  
**August 2011 - Present**

**Econalysis Consulting Services- Senior Consultant**  
**July 2000 to July 2011**

- Responsible for supporting client interventions in regulatory proceedings, including issues analyses & strategic direction, preparation of interrogatories, participation in settlement conferences, preparation of evidence and appearance as expert witness (where indicated by an asterix). Some of the more significant proceedings included:
  - Electricity (Ontario)
    - IMO 2000 Fees (OEB)
    - Hydro One Remote Communities Rate Application 2002-2004
    - OEB Transmission System Code Review (2003)
    - OEB Distribution Service Area Amendments (2003)
    - OEB Regulated Asset Recovery (2004)
    - OEB- 2006 Electricity Rate Handbook Proceeding\*
    - 2006 Rate Applications by Various Electricity Distributors
    - OEB - 2006 Guidelines for Regulation of Prescribed Generation Assets

- 2007 Rate Applications by Various Electricity Distributors
- OEB - 2007 Cost of Capital and 2<sup>nd</sup> Generation Incentive Regulation Proceeding
- Hydro One Networks 2007/2008 Transmission Rate Application
- 2008 Rate Applications by Various Electricity Distributors
- OEB – Cost of Capital for Ontario’s Regulated Utilities (2009)
- Hydro One Networks 2009/2010 Transmission Rate Application
- 2009 Rate Applications by Various Electricity Distributors
- 2010 Rate Applications by Various Electricity Distributors
- Hydro One Networks 2011/2012 Transmission Rate Application
- 2011 Rate Applications by Various Electricity Distributors
- 2012 Rate Applications by Various Electricity Distributors
- OEB – 2012 Renewed Regulatory Framework for Electricity Distributors
- Hydro One Networks 2013/2014 Transmission Rate Application
- 2013 Rate Applications by Various Electricity Distributors
- 2014 Rate Applications of Various Electricity Distributors
- OEB Residential Rate Design Policy (2014)
- 2015 Rate Applications for Various Electricity Distributors
- Hydro One Networks 2015/2016 Transmission Rate Application
- 2016 Rate Applications of Various Electricity Distributors
- Electricity (British Columbia)
  - BC Hydro IPP By-Pass Rates
  - BC Hydro Heritage Contract Proposals
  - BC Hydro’s 2004/05 & 2005/06; 2006/07 & 2007/08; 2008/09 & 2009/10; 2010/2011: and 2011/12-2013/14 Revenue Requirement Applications
  - BC Hydro’s CFT for Vancouver Island Generation – 2004
  - BC Hydro’s 2005 Resource Expenditure and Acquisition Plan
  - BC Hydro’s 2006 Residential Time of Use Rate Experiment Application
  - BC Hydro’s 2006 Integrated Electricity Plan
  - BC Hydro’s 2007 Rate Design Application
  - BC Hydro’s 2008 Residential Inclining Block Rate Application
  - BC Hydro’s 2009 GS Rate Design Application
  - BC Hydro’s 2015 Rate Design (and Cost of Service) Application
  - BC Transmission Corporation – Open Access Transmission Tariff Application - 2004
  - BCTC’s 2005/06; 2006/07, 2008/10 and 2010/2011 Revenue Requirement Applications
  - BCTC’s – 2005 Vancouver Island Transmission Reinforcement Project
  - BCTC’s – 2007 Interior-Lower Mainland Transmission Application
  - BCTC’s 2009-2018 Capital Plan
  - BCTC’s 2011 Capital Plan Update
  - Fortis BC’s 2005 Revenue Requirement and System Development Application
  - Fortis BC’s 2006; 2007, 2008, 2009, 2010, 2011, 2012 and 2013 Revenue Requirement Applications
  - Fortis BC’s 2007/08 and 2009/10 Capital Plan and System Development Plans
  - FortisBC’s 2007 Rate Design Application

- Fortis BC's 2009 Cost Allocation and Rate Design Application
- Fortis BC's 2011 Residential Inclining Block Rate Application
- Fortis BC's 2011 Capital Plan
- FortisBC's 2012 Integrated System Plan Review
- BCUC - 2012 Generic Cost of Capital Review
- BC Hydro/Fortis BC 2013 Purchase Power Agreement
- BC Hydro 2013 Residential Inclining Block Rate Re-Pricing
- FortisBC's 2014-2018 PBR Plan and Annual Reviews
- Electricity (Quebec)
  - Hydro Québec - Distribution's 2002-2011 Supply Plan\*
  - Hydro Quebec - Distribution's 2002-2003 Cost of Service and Cost Allocation Methodology\*
  - Hydro Québec - Distribution's 2004-2005 Tariff Application\*
  - Hydro Québec - Distribution's 2005/2006 Tariff Application\*
  - Hydro Québec - Distribution's 2005-2014 Supply Plan\*
  - Hydro Québec - Distribution's 2006/2007 Tariff Application\*
  - Hydro Québec - Transmission's 2005 Tariff Application\*
  - Hydro Québec - Distribution's 2006 Interruptible Tariff Application
  - Hydro Québec - Distribution's 2006 Cost Allocation Work Group
  - Hydro-Québec - Transmission's 2007 Tariff Application
  - Hydro-Québec - Distribution's 2007/08 Tariff Application\*
  - Hydro-Québec - Transmission's 2008 Tariff Application
  - Hydro-Québec - Distribution's 2008/09 Tariff Application\*
  - Hydro Québec - Distribution's 2008-2017 Supply Plan
  - Hydro-Québec - Transmission's 2009 Tariff Application
  - Hydro-Québec - Distribution's 2009/10 Tariff Application\*
  - Hydro Québec - Distribution's 2014-2023 Supply Plan
- Electricity (Manitoba)
  - Manitoba Hydro's Status Update Re: Acquisition of Centra Gas Manitoba Inc.\*
  - Manitoba Hydro's Diesel 2003/04 Rate Application
  - Manitoba Hydro's 2004/05 and 2005/06 Rate Application\*
  - Manitoba Hydro/NCN NFAAT Submission re: Wuskwatim\*
  - Manitoba Hydro's 2005 Cost of Service Methodology Submission\*
  - Manitoba Hydro's 2007 Rate Adjustment Application
  - Manitoba Hydro's 2008 General Rate Application\*
  - Manitoba Hydro's 2008 Energy Intensive Industry Rate Application
  - Manitoba Hydro's 2009 Rate Adjustment Application
  - Manitoba Hydro's 2010-2012 General Rate Application
  - Manitoba Hydro's 2010 and 2011 Diesel Community Rate Applications
  - Manitoba Hydro's 2013-2014 General Rate Application
  - Manitoba Hydro's 2013 NFAAT Submission re: Keeyask and Conawapa\*
  - Manitoba Hydro's 2015-2016 General Rate Application
  - Manitoba Hydro's 2016 Interim Rate Application

- Electricity (Saskatchewan)
  - Saskatchewan Power's 2008 Cost Allocation Methodology Review
- Natural Gas Distribution
  - Enbridge Consumers Gas 2001 Rates
  - BC Centra Gas Rate Design and Proposed 2003-2005 Revenue Requirement
  - Terasen Gas (Vancouver Island) LNG Storage Project (2004)
  - BCUC – 2012 Generic Cost of Capital Proceeding
- Telecommunications Sector
  - Access to In-Building Wire (CRTC)
  - Extended Area Service (CRTC)
  - Regulatory Framework for Small Telecoms (CRTC)
- Other
  - Acted as Case Manager in the preparation of Hydro One Networks' 2001-2003 Distribution Rate Application
  - Supported the implementation of OPG's Transition Rate Option program prior to Open Access in Ontario
  - Prepared Client Studies on various issues including:
    - The implications of the 2000/2001 natural gas price changes on natural gas use forecasting methodologies.
    - The separation of electricity transmission and distribution businesses in Ontario.
    - The business requirements for Ontario transmission owners/operators.
    - Various issues associated with electricity supply/distribution in remote First Nations' communities
  - Member of the OEB's 2004 Regulated Price Plan Working Group
  - Member of the OEB's 2005/06 Cost Allocation Technical Advisory Team
  - Member of the OEB's 2008 3<sup>rd</sup> Generation Incentive Regulation Working Group
  - Member of the IESO Technical Panel (April 2004 to April 2010)
  - Member of the OEB's 2011 Cost Allocation Working Group
  - Member of the OEB's 2012 Network Investment Planning Work Group
  - Member of the OEB's 2012 Defining and Measuring Performance (4<sup>th</sup> Generation Incentive Regulation) Work Group
  - Member of the OEB's Unmetered Load Cost Allocation Working Group (2012-2015)
  - Member of the OEB's 2013 Standby Rate Working Group
  - Member of the OEB's 2016 Pole Access Charge Working Group

## **Hydro One Networks**

### **Manager - Regulatory Integration, Regulatory and Stakeholder Affairs (April 1999 to June 2000)**

- Supervised professional and administrative staff with responsibility for:
  - providing regulatory research and advice in support of regulatory applications and business initiatives;

- ensuring regulatory requirements and strategies are integrated into business planning and other Corporate processes;
  - providing case management services in support of specific regulatory applications.
- Acting Manager, Distribution Regulation since September 1999 with responsibility for:
  - coordinating the preparation of applications for OEB approval of changes to existing rate orders; sales of assets and the acquisition of other distribution utilities;
  - providing input to the Ontario Energy Board's emerging proposals with respect to the licences, codes and rate setting practices setting the regulatory framework for Ontario's electricity distribution utilities;
  - acting as liaison with Board staff on regulatory issues and provide regulatory input on business decisions affecting Hydro One Networks' distribution business.
- Supported the preparation and review before the OEB of Hydro One Networks' Application for 1999-2000 transmission and distribution rates.

## **Ontario Hydro**

### **Team Leader, Public Hearings, Executive Services (Apr. 1995 to Apr. 1999)**

- Supervised professional and admin staff responsible for managing Ontario Hydro's participation in specific public hearings and review processes.
- Directly involved in the coordination of Ontario Hydro's rate submissions to the Ontario Energy Board in 1995 and 1996, as well as Ontario Hydro's input to the Macdonald Committee on Electric Industry Restructuring and the Corporation's appearance before Committees of the Ontario Legislature dealing with Industry Restructuring and Nuclear Performance.

### **Manager – Rates, Energy Services and Environment (June 1993 to Apr. 95)**

#### **Manager – Rate Structures Department, Programs and Support Division (February 1989 to June 1993)**

- Supervised a professional staff with responsibility for:
  - Developing Corporate rate setting policies;
  - Designing rates structures for application by retail customers of Ontario Hydro and the municipal utilities;
  - Developing rates for distributors and for the sale of power to Hydro's direct industrial customers and supporting their review before the Ontario Energy Board;
  - Maintaining a policy framework for the execution of Hydro's regulation of municipal electric utilities;
  - Reviewing and recommending for approval, as appropriate, municipal electric utility submissions regarding rates and other financial matters;
  - Collecting and reporting on the annual financial and operating results of municipal electric utilities.
- Responsible for the development and implementation of Surplus Power, Real Time Pricing, and Back Up Power pricing options for large industrial customers.

- Appeared as an expert witness on rates before the Ontario Energy Board and other regulatory tribunals.

### **Section Head – Rate Structures, Rates Department**

#### **November 1987 to February 1989**

- With a professional staff of eight responsibilities included:
  - Developing rate setting policies and designing rate structures for application to retail customers of municipal electric utilities and Ontario Hydro;
  - Designing rates for municipal utilities and direct industrial customers and supporting their review before the Ontario Energy Board.
- Participated in the implementation of time of use rates, including the development of retail rate setting guidelines for utilities; training sessions for Hydro staff and customers presentations.
- Testified before the OEB on rate-related matters.

### **Superintendent – Rate Economics, Rates and Strategic Conservation Department**

#### **February 1986 to November 1987**

- Supervised a Section of professional staff with responsibility for:
  - Developing rate concepts for application to Ontario Hydro's customers, including incentive and time of use rates;
  - Maintaining the Branch's Net Revenue analysis capability then used for screening marketing initiatives;
  - Providing support and guidance in the application of Hydro's existing rate structures and supporting Hydro's annual rate hearing.

### **Power Costing/Senior Power Costing Analyst, Financial Policy Department**

#### **April 1980 to February 1986**

- Duties included:
  - Conducting studies on various cost allocation issues and preparing recommendations on revisions to cost of power policies and procedures;
  - Providing advice and guidance to Ontario Hydro personnel and external groups on the interpretation and application of cost of power policies;
  - Preparing reports for senior management and presentation to the Ontario Energy Board.
- Participated in the development of a new costing and pricing system for Ontario Hydro. Main area of work included policies for the time differentiation of rates.

### **Ontario Ministry of Energy**

#### **Economist, Strategic Planning and Analysis Group**

#### **April 1975 to April 1980**

- Participated in the development of energy demand forecasting models for the province of Ontario, particularly industrial energy demand and Ontario Hydro's demand for primary fuels.
- Assisted in the preparation of Ministry publications and presentations on Ontario's energy supply/demand outlook.

- Acted as an economic and financial advisor in support of Ministry programs, particularly those concerning Ontario Hydro.

## **EDUCATION**

### **Master of Applied Science – Management Science**

- University of Waterloo, 1975
- Major in Applied Economics with a minor in Operations Research
- Ontario Graduate Scholarship, 1974

### **Honours Bachelor of Science**

- University of Toronto, 1973
- Major in Mathematics and Economics
- Alumni Scholarship in Economics, 1972