MANITOBA PUBLIC UTILITES BOARD

MANITOBA HYDRO

COST OF SERVICE

METHODOLOGY REVIEW

EVIDENCE PREPARED BY

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FOR

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MANITOBA SOCIETY OF SENIORS

(CAC/MSOS)

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1 BACKGROUND

On November 30th, 2001, Manitoba Hydro submitted a Status Update Filing to the Manitoba Public Utilities Board (MPUB). As part of the materials presented, Manitoba Hydro filed a Cost of Service Study based on a revised methodology adopted by the Company's Board of Directors in January of that year. The more significant proposed changes were with respect to:

- The functionalization of Transmission costs, with HVDC lines other than the Dorsey Converter station being assigned to Generation (as opposed to Transmission),
- The classification of Transmission costs as 100% demand-related and their allocation to customer classes based on 12 monthly coincident peaks (12CP),
- The classification of Generation costs based on the forecast marginal values of capacity and energy and the subsequent allocation of the costs to customer classes on a seasonal basis, and
- The allocation of Net Export Revenues to customer classes based on the total allocated costs for each class (excluding directly assigned costs).

However, during the course of the proceeding, Manitoba Hydro indicated that it was not able to provide, for reasons of commercial sensitivity, the marginal cost information necessary to support its proposed classification of Generation costs. As a result, on March 27th, 2002, the Company filed a revised Cost of Service Study whereby:

- The total costs in the Generation and Transmission functions were classified between energy and demand based on System Load Factor (as per previous studies),
- Transmission costs were classified as 100% demand-related and allocated based on 12CP (as originally proposed),
- The remaining demand-related costs were assigned to Generation and allocated to customer classes based on their average demand during the top 50 coincident load hours in the winter and the top 50 coincident load hours in the summer (referred to as 2CP).

Winnipeg Hydro was also removed as a customer class in recognition of its pending sale to Manitoba Hydro.

In its February 3rd, 2003 Decision (Order 7/03), the MPUB agreed with a number of the cost of service methodology changes proposed by Manitoba including: a) the division of assets between the generation and transmission functions; b) the classification of transmission function costs as 100% demand-related and c) the allocation of demand-related generation costs to customer classes based on 2CP. The MPUB rejected the Company's proposal to allocate transmission costs based on 12CP and, instead, directed that the allocation be done on a 2CP basis similar to that for generation.

The two issues on which the Board did not issue definitive direction were with respect to the classification of generation costs and the treatment of export revenues. With respect to the former, the Board directed that Manitoba Hydro complete a review of generation cost classification methodologies by December 31, 2003. With respect to the allocation of net export revenues, the Board expressed the view that "it continues to be appropriate to allocate the net export revenues derived from that capacity (i.e., generation and transmission capacity) in proportion to class responsibility for generation and transmission costs"[1]. However, it expressed concerns about the "costs" Manitoba Hydro included in the calculation of net export revenues. Manitoba Hydro was directed to prepare a new cost of service study that included the creation of a firm export class (to which costs would be allocated on a fully embedded basis) and an opportunity export class (to which only energy costs would be allocated). The MPUB suggested that once this information was filed "the allocation methodologies may require further consideration by the Board"[2].

On March 19, 2003, Manitoba Hydro filed an application with the Board requesting that it review and vary certain directives contained in Order 7/03. Two of Manitoba Hydro's requests were related specifically to the determination and allocation of net export

[1] Board Order 7/03, page 97
[2] Board Order 7/03, page 98

revenues. In both cases, Manitoba Hydro requested that the original Order be varied to permit the Company to further explore options for creating export classes and determining net export revenue and to also explore options for the allocation of net export revenues. The Board agreed to both of these requests and set a filing date of December 31, 2003 for the results[3].

In January 2004, Manitoba Hydro filed a Rate Application with the MPUB requesting increases in its rates for 2004/05 and 2005/06. As part of this Application, the Company filed an actual cost of service study for 2002/03 and a prospective cost of service study for 2003/04. These studies incorporated the findings of the MPUB in Orders 7/03 and 154/03 with a number of exceptions and caveats, including:

- The Cost of Service studies did not include an Export class of service. Rather net export revenues were determined and allocated in the same manner as previously approved by the MPUB.
- The Cost of Service studies reflected the MPUB's findings in Order 7/03 and did not include any changes as result of the study Manitoba Hydro was directed to undertake regarding the classification of generation costs.

During the course of the proceeding Manitoba Hydro provided a copy of a study entitled "Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies" prepared for it by NERA[4]. The study recommended a number of fundamental changes to the way Manitoba Hydro classifies and allocates generation and transmission cost and export revenues, including[5]:

- The creation of an export class and the allocation of costs to this class using the same allocation method as for domestic customers.
- Crediting net export revenues in a minimally distorting way such as based on G+T+D costs.
- Classifying and time-differentiating generation costs using the pattern of Manitoba Hydro's opportunity costs.

[3] Board Order 154/03, pages 34-35
[4] April 1, 2004 letter to the PUB from K.M. Tennenhouse, General Counsel and Corporate Secretary, Manitoba Hydro.
[5] PUB/MH II-3 a)

- Classifying transmission costs using a line specific approach between export and domestic lines, with all export lines allocated on annual class energy use and domestic lines allocated on demand (i.e., 2CP).
- Allocating generation costs using class energy use (and demand in the 50 highest hours of the season if there is a separate seasonal opportunity cost of capacity) by season and diurnal period.

In response to information requests, Manitoba Hydro generally supported and concurred with the recommends made by NERA. However, Manitoba Hydro indicated that it did not intend to amend its current application to reflect the results of the Study in the current GRA[6]. The Company indicated that more work needed to be done before the NERA recommendations could be implemented.

In its July 28th, 2004 Order (101/04), the MPUB directed Manitoba Hydro to file, by no later than January 31, 2005, three separate Cost of Service Studies based on:

1. Manitoba Hydro's existing methodology;
2. Implementation of the NERA recommendations; and
3. Manitoba Hydro's preferred approach and methodology, including supporting rationale.

In addition, Manitoba Hydro was directed to provide a study that considered the merits of allocating less expensive generation to domestic classes and the higher cost generation to domestic and export classes.

In February 2005, Manitoba Hydro filed the requested studies with the MPUB and indicated a preference for the NERA methodology. However, subsequently a further modification to the NERA method was adopted and in October 2005 Manitoba Hydro filed its recommended Cost of Service Methodology with the MPUB. The modification called for the creation of two export sub-classes: Firm Exports and Non-Firm (or Opportunity) Exports. Firm Exports would attract embedded costs in the same way as domestic service. Opportunity Exports would only attract variable costs (as is currently the case for all exports).

[6] PUB/MH II-3 b) & c)

On November 10th, 2005, the MPUB issued a Notice of Review establishing a public hearing regarding Manitoba Hydro's Cost of Service Methodology proposals.

2 PURPOSE OF EVIDENCE

Upon receipt and review of Manitoba Hydro's Cost of Service Methodology proposals, the Consumers' Association of Canada – Manitoba and the Manitoba Society of Seniors (CAC/MSOS) retained Econalysis Consulting Services to assist and advise the two associations regarding their participation in the proceeding. As part of its engagement ECS was requested to prepare evidence that would assist both the MPUB, CAC/MSOS and other stakeholders in understanding the reasons for and the appropriateness of Manitoba Hydro's Cost of Service Methodology proposals.

The Evidence was prepared 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 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. His most recent experience with cost allocation matters includes:

- The preparation of evidence and appearance as an expert witness in both Phase 1 and Phase 2 of Régie proceedings (R-3492-2002) dealing with Hydro Quebec Distribution's (HQD's) 2002 and 2003 cost allocation proposals.
- The preparation of evidence and appearance as an expert witness in the Régie proceeding (R-3549-2004, Phase 2) dealing with Hydro Quebec Transmission's cost allocation proposals.

- The preparation of evidence and appearance as an expert witness in the Régie proceeding (R-3579-2005) dealing with HQD's 2005 cost allocation proposals.
- The preparation of evidence and appearance as an expert witness before the Manitoba Public Utilities Board with respect to its review of proposals filed by Manitoba Hydro in both 2002 and 2004 regarding cost allocation.
- Providing expert advice and support to clients in British Columbia participating in the BCUC proceedings dealing with BCTC's 2004 Open Access Transmission Tariff (OATT) Application.
- Member of the OEB's 2005/06 Technical Advisory Team regarding cost allocation for Ontario electricity distributors.

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

There are two key issues addressed by Manitoba Hydro's proposals, namely:

- The classification and allocation of generation costs, and
- The determination and allocation of net export revenues.

The evidence starts by discussing the purpose of a cost of service study, the key steps and the principles involved. Sections 4 and 5 deal with the two key issues. In each Section, there is a backgrounder containing a general discussion of the issue followed by a description of Manitoba Hydro's Recommended Method and, then, a more detailed assessment of the specific proposals put forward by Manitoba Hydro. Section 6 addresses a number of other issues that were noted during the review of Manitoba Hydro's Application and Information Request responses.

3 PURPOSE OF A COST OF SERVICE STUDY

One of the primary objectives in setting rates is that they should be "fair"[7]. In interpreting what is meant by "fair rates", one point on which there is a reasonable consensus is that fairness is achieved when customers pay what their service costs and there is an equal treatment of equals based on cost causation. In theory no two customers are exactly the same. However, for practical purposes, customers who have similar characteristics in terms of electricity use are grouped into rate classes and rates are then set for each class.

As a guide for determining the appropriate rates to be charged to each class of customers, gas and electric utilities generally perform a cost of service or cost allocation study. A cost of service study analyzes the components of the Company's costs and allocates or directly assigns plant investments and other assets as well as operating expenses among the various customer classes receiving service and, in some instances, among different services offered by the utility. The purpose of the study is to determine both the total and the unit costs of providing service to various customer classes. The results are then used to provide guidance in establishing the rate levels and designing the rate structures for each customer class so as to fairly apportion the total costs between customer classes and provide proper price signals. A cost of service study can also assist in identifying the costs of providing individual services in those jurisdictions where rates are to be unbundled.

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

1) Functionalization of 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.
2) Classification of each function's costs according to the system design or operating characteristics that caused those costs to be incurred. In the case of

[7] Charles F. Philips, Jr., The Regulation of Public Utilities, (pages 410-411)

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 of each functionalized and classified cost component to specific customer classes based on each class' contribution to the specific cost driver selected.

While the process appears straightforward and logical, the nature of utility operations is characterized by the existence of common or joint use facilities (and activities) that are used to support the provision of more than one product/service and/or serve more than one customer class. As a result, while cost analysts may strive to identify and isolate plant and expenses incurred exclusively to serve a specific customer class or group of customers, it is unrealistic to assume that large portions of a utility's plant investment and expenses can be directly assigned. In addition, there are practical constraints (e.g. time and budgets) that will limit the extent to which costs can be directly tracked and assigned.

In evaluating any cost of service study primary consideration is generally given to the need to reflect cost causality to the extent possible. In this regard, while industry standards and precedents have been established which can assist cost analysts in performing cost of service studies, recognition must also be given to the specific utility's circumstances (e.g., its operating characteristics and design). Other considerations include equity, efficiency, stability of results over time, transparency, logical consistency and practical limits of implementation.

Finally, it should be noted that the concept of "cost causality" is sometimes not as straightforward as one would expect. It is generally accepted that customers not using a particular utility asset or service are not responsible for its costs. However, not all customers using an asset/service are necessarily equally responsible for the costs incurred. This issue is usually be captured through the choice of the “cost driver” used in the allocation phase of the Cost of Service Study. However, debates sometimes arise as to whether:

a) Different rate classes are “equals” and, when they are not, how differences can be reflected in the cost of service methodology;
b) How “cost causation” should be determined and, in particular, whether all those utilizing an asset should bear some of the burden for cost responsibility.

As noted earlier, there are two key cost of service methodology issues outstanding as a result of the MPUB’s Orders 7/03; 154/03 and 101/04. The first of these is the classification (and subsequent allocation) of generation costs. The second is the treatment of export revenues in term of how net export revenues are calculated (i.e., gross exports revenues less costs) and allocated to customer classes.

4 CLASSIFICATION OF GENERATION COSTS

4.1 Background

Utilities typically have a number of generation options to choose from and the choice (say between hydraulic and fossil) takes into account both the energy and the capacity requirement of the utility’s customers. 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[8]. Thus, apart from fuel costs, which can readily be classified as energy-related, the other costs associated with the Generation function (e.g., depreciation, interest and plant O&M) are typically associated with the provision of both demand and energy. However, there is no generally accepted approach for classifying this portion of generation costs. Rather, there are a number of different approaches that could be and, indeed, are used by utilities. This is evidenced

[8] For example, utilities will invest in hydraulic plants where the capital cost per kW is higher than for gas-fired generation, if the plant is expected to operate for a significant portion of the year such that the lower fuelling/operating costs will offset the higher initial capital cost over the long run.

by the recent NERA report (Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies[9]) prepared for Manitoba Hydro which indicated that a number of different methods were employed by the utilities it surveyed.

While the use of system load factor (as currently employed by Manitoba Hydro) is fairly straightforward it provides, at best, a directionally correct link to cost causality. This is because it simply reflects the fact that the higher a utility's load factor the more dollars the utility is likely to spend on fueling costs and the more dollars it is likely to invest in fixed plant in order to reduce overall fueling costs. However system load factor cannot be considered as providing an accurate measure or tracking of the relative costs incurred to provide for customers' capacity versus energy requirements.

In fact in the PUB's 1991 Decision[10] where the classification of Generation costs was considered in some detail, the Board observed that many of the methods presented produced similar results and concluded that for all practical purposes, it was not necessary to choose between minor variations of methods and that the method used by Manitoba Hydro fairly reflected cost causation, while offering the advantages of simplicity and relative stability. In its report, one of the benchmarks used by the Board in testing the reasonableness of the percentage of costs classified to energy was the value of export revenues. In fact the Board observed that "both equity and efficiency considerations support a classification which maintains generation and transmission energy cost for domestic customers at the same level as the export value of energy".[11] Finally, it should be noted that in the same decision the Board observed that, despite its findings, it did not wish to preclude or discourage further research on cost of service methodology or proposals for changes in the future[12].

One can not accurately determine the portion of costs that were incurred to support energy versus capacity requirements without a full understanding and analysis of the

[9] Appendix 11.2
[10] Order 29/91, pages 33-34
[11] Order 29/91, page 33
[12] Order 29/91, page 34

rationale underlying all of the investment decisions made by the utility in the past. Furthermore, the factors affecting such trade-offs change over time[13]. As result, a more practical approach is to use a utility's current marginal costs of supply to establish the value of such tradeoffs and the relatives amounts of Generation costs that should be classified as energy as opposed to demand related. Such an approach allows the cost of service methodology to better reflect cost causation than simply using system load factor as it captures the relative costs that the utility would incur today in order to meet demand and energy needs.

4.2 Manitoba Hydro's Recommended Method

Manitoba Hydro's proposal is to classify generation costs into four time periods[14] on the basis of marginal costs. The marginal cost weightings (by time period) are first derived from the average (inflation adjusted) Surplus Energy Program[15] (SEP) rates for the period January 1, 1999 to October 4, 2004. These marginal cost ratios are then multiplied by the seasonal energies (winter and summer/peak and off-peak[16]) totalled over the relevant rate classes. The resulting relative weighted energy values are used to assign the Generation costs to time periods[17]. The Generation costs assigned to each period are then allocated to the relevant rate classes based on each class' share of the period's total energy.

The approach recommended by Manitoba Hydro for classifying (and allocating) Generation costs is very similar to that recommended by NERA. The only difference is the source of data used to determine the marginal cost weightings by time period. In its report, NERA used commercially available Platt's data[18]. The following Table

[13] As an example of these points, see the discussion regarding the Brandon GS in Section 5.3.2
[14] PUB/MH I-40 a) and CAC/MSOS/MH II-8 a)
[15] For details on the SEP see Appendix 11 of the 2002 Status Update Filing
[16] MIPUG/MH I-3 f)
[17] Appendix 11.1, Section A, page 18
[18] Appendix 11.2, page 34 and Appendix 11.1, Section A. page 23

summarizes the impact on the Revenue to Cost Ratios of Manitoba Hydro's Recommended Method versus the Current Method which relies on system load factor.

TABLE 1

**IMPACT OF ALLOCATING GENERATION COSTS
BASED ON MARGINAL WEIGHTINGS BY TIME PERIOD**

	REVENUE TO COST RATIOS	
CLASS	**CURRENT METHOD**	**REVISED GENERATION ALLOCATION**
Residential	92.2	93.0
GSS ND	103.1	103.4
GSS D	106.0	105.5
GSM	102.9	102.4
GSL <30 kV	94.0	93.1
GSL 30-100 kV	109.4	108.5
GSL > 100 kV	114.7	113.2
Area & Roadway Lighting	105.2	105.7

Source: PUB/MH I-30 d)

4.3 Comments

4.3.1 100% Energy Classification

Manitoba Hydro's Recommended Method does not follow the traditional approach of classifying Generation costs as capacity and energy related, rather Generation costs are assigned to four time periods and then allocated to rate classes based on their energy use in each time period[19]. A question therefore arises as to whether the

[19] Note: A small portion of Generation costs (i.e., the curtailable load credit offset) are deemed to be demand-related and allocated to customer classes based on 2CP.

Recommended Method captures the fact that Generation costs are jointly incurred to provide both capacity and energy.

In general terms, capacity costs are the costs incurred to meet customers' maximum load requirements, as opposed to energy costs which are incurred to meet the total energy needs of the customers throughout the year. Capacity costs can be associated with those hours of the year that are critical from a system perspective – typically viewed as those hours in which there is high probability that demand will exceed available generation capacity. In Manitoba Hydro's case, the Current (Cost of Service) Method allocates capacity costs to customer classes based on each class' average contribution to the 50 highest load hours in the winter and the 50 highest load hours in the summer[20]. Conceptually, this is the same as allocating capacity costs to customer classes based on their energy use during these 100 critical hours of the year.

The use of hourly marginal costs (where the marginal costs include both marginal energy and capacity costs) to weight the various hours in the year is an analogous approach. As Manitoba Hydro has explained in response to MIPUG/MH II-4, "generation costs are classified into four different cost drivers" reflecting the varying seasonal and diurnal costs. To the extent the marginal costs used to develop the "cost drivers" capture both the cost of energy and capacity, there is no need to separately classify generation costs as capacity or energy-related. The value of both capacity and energy are captured in same weighting factor. As a result, the need to "classify" generation costs becomes redundant.

A related question is whether the number of periods used (four) is sufficient to properly reflect cost causality. Manitoba Hydro has indicated that it considers the results of the current study to be representative. However, the Company has acknowledged that future studies could incorporate narrower definitions of the peak and off-peak periods[21].

[20] Appendix 11.1, page 12
[21] PUB/MH II-2 b)

TABLE 2

COMPARISON OF PEAK PERIOD ALLOCATORS
RECOMMENDED Versus CURRENT METHOD

	Winter Peak (kWh)	(%)	Summer Peak (kWh)	(%)	Average (%)	2CP (MW)	(%)
Residential	2,195,343,308	35.2%	1,433,096,830	28.3%	31.7%	1189.9	37.1%
GSS ND	527,717,792	8.5%	440,454,087	8.7%	8.6%	271.1	8.5%
GSS D	560,679,463	9.0%	457,237,233	9.0%	9.0%	281.9	8.8%
GSM	560,679,463	9.0%	457,237,233	9.0%	9.0%	281.9	8.8%
GSL<30	450,051,564	7.2%	443,457,805	8.8%	8.0%	226.8	7.1%
GSL 30-100	202,073,039	3.2%	189,885,594	3.7%	3.5%	96.9	3.0%
GSL>100	1,361,658,554	21.8%	1,230,045,997	24.3%	23.1%	633.2	19.8%
Streetlights	19,032,914	0.3%	13,842,831	0.3%	0.3%	8.7	0.3%

SOURCE: Appendix 11.1, page 85
Appendix 11.3, page 18

Table 2 sets out a comparison of the relative values by class of the 2CP allocation factors used in the Current Method and energy use in the winter and summer peak periods used to establish the weighted energy allocation factors for the Recommended Method. For some of the customer classes the weightings are similar (e.g., GSS and GSM), but for others (e.g., Residential and GSL) the differences are more material. If one assumes that the highest load hours are also the highest cost hours, the results suggest that the use of four broadly defined periods may result in an under allocation of generation costs to residential customers and a corresponding over allocation to GSL customers. As a result, there is a need to consider a “finer” definition of both the winter and the summer peak periods.

In the extreme, one could use 8760 periods, one for each hour of the year. However, as Manitoba Hydro has noted[22]: “at some point any advantage in precision would be

[22] PUB/MH II-2 b)

outweighed by the greater complexity". As a start, it is suggested that Manitoba Hydro adopt the six periods currently used in the actual SEP program definition (see also Section 4.3.3).

4.3.2 Use of SEP Values as a Proxy for Marginal Costs

In simple terms, the marginal cost of generation is the change in cost as a result of supplying a small increase (or responding to a decrease) in domestic customer usage. Marginal generation costs include both a marginal energy cost and a marginal capacity cost component. Typically, marginal energy costs reflect the changes in costs as a result of operating and maintaining the generation system to meet the energy requirements associated with increased customer usage. This can include a combination of operating & maintenance costs, fuelling costs, purchased power costs and, over the longer term, increased investment generation facilities associated with lowering energy production costs. Marginal capacity costs typically represent the cost of facilities (or firm purchases) incurred to meet the reliability requirements of customers from a system capacity perspective.

As Manitoba Hydro has noted[23], in many hours of the year the price of electricity on the export market represents the Company's marginal cost of supplying capacity and energy to its domestic customers. The reason is that Manitoba Hydro's demand/supply situation is such that new plant is not needed until 2020 to meet domestic requirements[24]. In the interim, it is assumed that surplus dependable energy can and will all be sold as firm exports[25]. As a result, if domestic customers increase their usage this reduces the surplus dependable energy available for export and, in turn, reduces the firm export revenues. However, under certain water flow conditions, the marginal cost of generation will be determined by the cost of purchased imports or dispatching idle Manitoba Hydro thermal generation[26].

[23] PUB/MH I-26
[24] PUB/MH I-22 a) and PUB/MH II-10
[25] CAC/MSOS/MH II-4 d)
[26] PUB/MH I-26 and CAC/MSOS/MH II-b)

Manitoba Hydro's Recommended Method uses historical SEP rates as a proxy for the marginal cost of generation. SEP rates are determined based on "the lesser of Manitoba Hydro's foregone export sales (market price) or 110% of the marginal cost of supply where the supply could be either from Manitoba Hydro generation or power purchased from the market"[27]. In application, this means that for most hours of the year the SEP rates reflect the prices received from opportunity exports. However, during periods when there is insufficient transmission to either a) export all of Manitoba Hydro's surplus energy or b) meet Manitoba Hydro's need to buy energy, then the SEP rates will reflect the cost of imports or the cost of generating electricity from thermal sources[28].

Opportunity sales are generally sourced from non-dependable energy sources. They may include short-term firm sales but also include spot market sales[29]. As a result, opportunity sales do not include the same type of long-term capacity commitment as firm sales[30]. A question therefore arises as to whether SEP rates capture the value of generation capacity and are a reasonable proxy for Manitoba Hydro's marginal costs. However, opportunity or spot prices are also influenced by market conditions and, when energy is scarce, can be higher than contracted firm market prices[31]. Overall, Manitoba Hydro has indicated that the historical SEP prices are reasonably close to, but slightly lower than firm market prices[32]. This can also be seen in Table 3 which compares historical firm and opportunity export prices.

[27] CAC/MSOS/MH I-11 b)
[28] CAC/MSOS/MH I-11 b) and RCM/TREE I-5 a)
[29] PUB/MH I-12 b) and CAC/MSOS/MH I-16 a)
[30] PUB/MH I-12 a)
[31] RCM/TREE/MH E-5 a) and CA/MSOS/MH I-11 e)
[32] RCM/TREE/MH I-5 a) & b) and

TABLE 3

AVERAGE EXPORT PRICES
($/MWh)

Year	Firm Exports	Opportunity Exports
2001/02	52.84	45.24
2002/03	51.70	44.22
2003/04	48.47	57.13
2004/05	48.00	51.83
2005 (partial)	58.06	52.16
Average	51.81	50.12

Note: The 2005 values are for the period April to November 2005

Source: PUB/MH I-22 c) {revised}

It must also be emphasized that what is relevant for the classification of generation costs is not the overall level of opportunity export prices, but their relative values by time period. Manitoba Hydro states that “it believes the on-peak/off-peak differential in SEP rates can act as a reasonable proxy for capacity considerations as well as energy considerations”[33]. A peak/off peak differential that captures capacity considerations will be higher than one that just reflects energy cost differences by period. Table 4 compares the relative peak/off peak marginal cost estimates by season based on: a) SEP rates and b) Manitoba Hydro’s marginal cost calculations of meeting firm load (similar to those used in the initial 2002 filing). The peak/off peak differentials based on the SEP rates are actually greater than those currently reflected in Manitoba Hydro’s marginal cost calculations. It must be acknowledged that Manitoba Hydro’s current methods for determining firm load marginal costs do not distinguish between peak and off-peak energy related costs. However, its is reasonable to conclude that the SEP rates likely provide a better estimate of the difference between peak and off peak marginal costs than Manitoba Hydro’s current methods for estimating marginal costs.

[33] CAC/MSOS/MH I-11 e)

TABLE 4

PEAK / OFF PEAK DIFFERENTIALS

	Winter	Summer
SEP Rates	1.62	1.92
Current Marginal Costs	1.25	1.53

Sources: Appendix 11.1, page 18
CAC/MSOS/MH II-26 a)

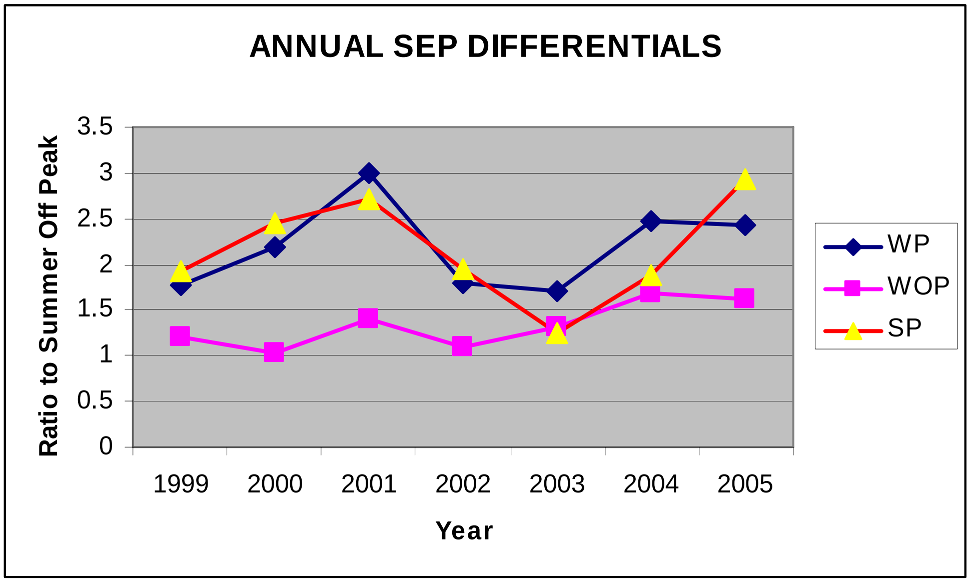
4.3.3 Derivation of Marginal Cost Weightings

The actual weightings by time period are derived from the average (inflation adjusted) SEP rates for the period January 1, 1999 to October 4, 2004[34]. As Manitoba Hydro notes "ideally, one would want to reflect near term market conditions over a range of water conditions to determine a reasonably representative set of marginal costs"[35]. The proposed approach seeks to achieve this result by averaging Manitoba Hydro's historical SEP prices for a number of years - which reflect a variety of system conditions. The averaging therefore provides a more representative value than, say, selecting just the most recent year. The use of an historical average could mask recent trends. However, as Manitoba Hydro has indicated[36] and Table 5 suggests, there are no readily apparent trends in the data.

[34] Appendix 11.1, page 18
[35] PUB/MH I-30 h)
[36] PUB/MH I-30 h)

TABLE 5

(Source: PUB/MH I-41 a)



As previously discussed, the period definitions used for the SEP differ materially from the peak/off peak used in the Cost of Service Study. The SEP period definitions are as follows[37]:

- Peak: Winter - 7 am to 11 am and 4 pm to 8 pm (Week Days, except Stat. Holidays)
  Summer - 12 pm to 8 pm (Week Days except Stat. Holidays)
- Shoulder: 7 am to 11 pm every day, excluding Peak hours,
- Off-Peak: 11 pm to 7 am (All Days)

In contrast, the Cost of Service study uses the standard 5 x 16 peak period definition where the peak period is Week Days from 7 am to 11 pm, excluding statutory holidays[38]. As result, it was necessary for Manitoba Hydro to convert the six-period SEP rates into marginal costs for four periods. Unfortunately, there is not a clean alignment between the SEP and the COSS time periods. This led to Manitoba Hydro having to develop a methodology for "splitting" the SEP rate for the shoulder period

[37] Status Filing Update, Appendix 11, page 3
[38] PUB/MH I-22 g); CAC/MSOS/MH II-8 a) and PUB/MH I-30 g)

between the COSS peak and off-peak periods. To do so, Manitoba Hydro had to make some simplifying assumptions about how the shoulder periods' SEP prices varied on an hour to hour basis[39]. A more straightforward approach would have been for Manitoba Hydro to adopt the 6 SEP periods for purposes of establishing the weighted generation costs.

4.3.4 Alternatives

In Board Order 101/04, Manitoba Hydro was directed[40] to file COSS based on:

- Manitoba Hydro's Existing COSS Methodology,
- The NERA Recommendations,
- The allocation of less expensive generation costs all to domestic customers, with higher cost generation being allocated between domestic and export customers on an in-service date basis as suggested by TREE/RCM, and
- Manitoba Hydro's preferred approach and methodology.

Manitoba Hydro has included the results for all four approaches in its current Filing.

With respect to the classification and allocation of generation costs, Manitoba Hydro's Recommended Method differs from the NERA Method in that it uses the SEP rates as a proxy for marginal costs as opposed to the Platt's data which was used by NERA. Manitoba Hydro has explained[41] that the SEP data is preferable to the generic Platt's data as it not only reflects prices for Manitoba Hydro sales in the interconnected MAPP market, but also reflects Manitoba Hydro's access to those prices and the effect of transmission constraints on the prices the Company can realize. The relative prices for SEP by time period vary from those derived using the Platt's data, particularly in the peak periods. However, to the extent the variation captures the export prices that are obtainable by Manitoba Hydro and also reflects the effect of local transmission constraints, the SEP data is preferable to Platt's.

[39] CAC/MSOS/MH I-11 g) & h)
[40] Board Order 101/04, page 32
[41] Appendix 11.1, page 23 and CAC/MSOS/MH I-11 d)

The Vintaging Alternative is discussed later in Section 5.3.9

4.3.5 Conclusions

- Manitoba Hydro's proposal to allocate generation costs to customer classes based on their energy use by time period and an assignment of generation costs to time periods that incorporates the marginal cost of capacity and energy is reasonable and represents an improvement, from a cost tracking perspective, over the Current Method.
- While the Recommended Method does not include the formal classification of generation costs into demand and energy-related costs, the use of marginal cost estimates that reflect both capacity and energy cost considerations can achieve the same result.
- Manitoba Hydro's SEP rates represent a reasonable estimate of marginal costs (for both capacity and energy). Furthermore, the use of a multi-year (inflation adjusted) average is reasonable as it represents a variety of system conditions.
- Manitoba Hydro should increase the number of time periods used in the allocation of generation costs and adopt the six periods currently used in the Surplus Energy Program.

5 TREATMENT OF EXPORT REVENUES

5.1 Background

Under the Current Method, net export revenues are determined by subtracting from gross export revenues 100% of power purchases; a share of fuel and water rental costs; NEB and US regulatory and legal costs and purchased transmission outside of Manitoba[42]. The resulting net export revenues are then allocated to domestic (grid-connected) customer classes in portion to their share of allocated Generation and Transmission costs (excluding directly assigned costs)[43]. Manitoba Hydro indicates that this approach has been in use since at least the late 1980's[44].

The Current practice with respect to net export revenues was first reviewed and approved by the MPUB in 1994[45]. It was reviewed again as part of Manitoba Hydro's Application for 1996 and 1997 rates and found to be appropriate[46]. The rationale in both cases was that export revenues result from generation and transmission built to provide firm service to domestic loads and that it was therefore consistent with the principle of cost causality to share net export revenues derived from this capacity in proportion to each domestic customer class' responsibility for the same facilities. It is also important to note that under the Current COSS methodology the question of whether a particular generation or transmission cost is directly assigned as a "cost of exports" in the determination of net export revenues has no real effect on the overall results of the COSS methodology. This is because all generation and transmission costs are grouped and allocated to customers using a common methodology. Similarly, the net export revenue credit is allocated to customer classes based on the allocated generation and transmission costs, which means the credit is also allocated using

[42] Appendix 11.1, page 15 and PUB/MH II-9 a)
[43] CAC/MSOS/MH I-15 a) & b)
[44] RCM/TREE/MH I-11 a), page 2
[45] RCM/TREE/MH I-11 a), page 3
[46] RCM/TREE/MH I-11 a), pages 3-5

effectively the same methodology[47]. As a result, the question of which costs should be associated with exports is interesting from a theoretical perspective but has no impact on the resulting Revenue to Cost Ratios that influence decisions regarding customers' rates.

As part of its Status Update filing, Manitoba Hydro proposed changes to both the allocation of generation and transmission costs and to the allocation of net export revenues[48]. 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 them). 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 on the basis of Generation and Transmission costs was distorting the cost of service study results and the resulting rates charged to customers[49]. This proposed change proved to be controversial. It also meant that that the results of the COSS methodology would vary depending upon what costs were "attributed" to exports in the calculation of net export revenues.

This drew attention to the issue of whether or not exports were attracting an appropriate share of costs. Particular stakeholders suggested[50] that if the PUB was to adopt an alternate approach for allocating net export revenues then the calculation of net export revenues should recognize that there are some embedded (i.e., fixed costs) associated with exports as well as the variable costs already associated with exports. Their position was that if such costs were included in the determination of net export revenues then alterative approaches (to the Current Method) of allocating net export revenues would be more acceptable. In its decision, the MPUB expressed the view[51] that "many direct and indirect costs related to export power sales are currently not included in

[47] CAC/MSOS/MH I-15 a)
[48] Status Update Filing, Appendix 12, pages 28-29
[49] Manitoba Hydro's 2002 Rebuttal Evidence, pages 18-20
[50] April 2002 Evidence Submitted on Behalf of MIPUG, page 37
[51] Board Order 7/03, page 97

Hydro's calculation of net export revenues". The Board directed[52] 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. It also provided direction on how the allocation of costs to these two new classes should be performed and confirmed its previous decision regarding how net export revenues should be allocated to customer classes.

Distinction Between Domestic and Export Customers

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 costs based revenue requirement. Overall, cost of service study 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[53] 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

[52] Board Order 7/03, page 98
[53] 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.

domestic requirements even if incremental revenues do not cover the incremental costs. However, a utility would not 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 also acknowledged[54] by NERA in their report on Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies prepared for Manitoba Hydro.

In a subsequent Order[55], the Board varied it 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[56] 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.

Overall, it would appear that 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

[54] Appendix11.2, pages 31-32
[55] Board Order 154/03, pages (vi) and (vii)
[56] Board Order 154/03, page 32

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.

5.2 Manitoba Hydro's Recommended Method

Manitoba Hydro's proposal calls for the creation of two export classes of power: i) Firm Exports and ii) Opportunity Exports. Firm Exports are export commitments made based on the availability of dependable water flows over and above those required to meet forecasted domestic requirements. In addition, there must be sufficient generating capacity in-service over above the reserve requirement needed to meet domestic load[57]. In contrast, Opportunity sales are made based on the availability of generation in excess of dependable supply. Based on the data presented in the current proposal, firm exports represent 55% of total export sales[58].

The Opportunity Export class is only assigned 45% of the variable costs attributed to all exports under the Current Method. In contrast, the Firm Export class attracts a full share of embedded Transmission and Generation costs, similar to any of the standard domestic customer classes[59]. The Generation and Transmission costs allocated to Firm Export and Domestic customers also include the remaining 55% of the costs that were directly assigned to exports under the Current Method.

For purposes of allocating Transmission costs, a distinction is made between domestic transmission lines and transmission lines that interconnect with other jurisdictions. The costs of Domestic transmission lines are allocated to classes (including Firm Exports) based on 2CP. However, the costs of interconnection lines are allocated to classes (again including Firm Exports) based on class energy use.

[57] PUB/MH I-14 a)
[58] Appendix 11.1, page 17
[59] Appendix 11.1, page 19

Net export revenues equal total export revenues less the costs assigned to Opportunity Exports and those allocated to Firm Exports. In Manitoba Hydro's Recommended Method, net export revenues are allocated to all domestic customer classes (including non-grid connected diesel communities) on the basis of the total allocated costs of all functions (not just Generation and Transmission)[60].

Overall, the Recommended Method's treatment of Export Revenues involves a number of changes in the COSS methodology including:

- The creation of two export classes: Firm and Opportunity
- The separation of transmission between Domestic and Interconnections
- The Allocation of Net Export Revenues based on Total Allocated Costs.

The following Table sets out the impact of each of these changes, along with the change in allocation of generation costs, on the Revenue to Cost Ratios for each of the Domestic customer classes. For a number of the classes, the impacts of the various changes tend to "net out" against each other, except for the change in allocation of Net Export Revenues.

TABLE 6

RECOMMENDED VERSUS CURRENT METHOD
IMPACT OF CHANGES ON CLASS RCC

	Residential	GSS ND	GSS D	GSM	0-30	GSL 30-100	>100	S/L
CURRENT METHOD RCC	92.2	103.1	106.0	102.9	94.0	109.4	114.7	105.2
IMPACT OF:								
1) Add Firm Export Class	-0.6	1.4	0.8	0.0	-0.5	0.8	1.5	0.0
2) Functionalize Transmission to Domestic and Export	0.2	0.1	0.0	0.1	0.0	-0.5	-0.7	-0.2
3) Allocaton of Generation on Weighted Energy	0.5	-0.3	-0.3	-0.2	-0.7	-0.5	-0.8	0.3
4) Allocate Net Export Revenue Based on All Allocated Costs	4.7	3.1	-1.1	-2.2	-2.7	-7.7	-11.5	1.8
RECOMMENDED METHOD RCC	97.0	107.4	105.4	100.6	90.1	101.5	103.2	107.1

SOURCE: MIPUG/MH I-6

[60] Appendix 11.1, page 19

5.3 Comments

5.3.1 Definition of Export Classes

A customer class represents a group of customers who have roughly the same service requirements. Manitoba Hydro has a variety of export contract arrangements, including:

- Border Accommodation, where retail customers in adjacent utilities do not have ready access to electrical service from the other power system due to geographic isolation[61]. These sales are made to the utilities concerned under contracts which are renewed on a periodic basis. Border Accommodation sales have the same service priority as domestic load and, for rate setting purposes are treated (and reported) as domestic load[62].
- Firm Power contracts, where Manitoba Hydro carries reserves and firm transmission to support the sale[63]. Energy sold under long term Firm Power contracts is sourced from dependable energy[64]. Firm power sales can also include short term sales (up to one year in duration). Such sales can be made from surplus energy in excess of dependable supply, but commitment to such sales would be dependent upon Manitoba Hydro's current surplus capacity and energy situation[65].
- System Participation Power, which is similar to Firm Power but where the customer provides its own reserves. The result is that System Participation sales are curtailed before Firm Power sales when there is insufficient capability to meet system commitments. Similar to Firm Power exports, long-term System Participation power sales are based on dependable energy while shorter term sales can be made from energy in excess of dependable energy[66].

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[61] PUB/MH I-12 c)
[62] PUB/MH II-12 c)
[63] PUB/MH II-25 c), page 2
[64] For a definition of dependable energy see PUB/MH I-21 b)
[65] PUB/MH I-12 b) and PUB/MH II-25 c)
[66] PUB/MH II-25 c)

- System Energy sales and similar products of a short-term nature, including both short term contracts and sales on a day ahead and real time basis in MISO, Ontario, Alberta and MAPP markets[67].

Under its Recommended Method, Manitoba Hydro has defined two export classes of power: Firm and Opportunity. Firm Exports are meant to capture those export commitments that are sourced out of dependable energy supply and would include Firm Power and System Participation Power contracts lasting longer than one-year. Opportunity Exports are contracts and sales obligations with duration of one year or less, including firm short-term contracts[68]. As a result, Opportunity sales are made from the existing system and are based on existing system conditions. While the two export classes do not capture all of the differences between Manitoba Hydro's various export arrangements, they do capture some of the major differences and considerations:

- Long term firm and system participation power contracts rely on the same dependable energy (and capacity) as is required to meet domestic loads. Having made such long term export contracts, these resources are no longer available to meet domestic load, should circumstances change.
- Opportunity sales, even those representing short-term firm commitments are made from existing capacity[69]. Indeed, given the short-timeframes, it is unlikely that additional capacity could be brought into service to meet the request for short-term supply – even if it was demonstrated to be economic to do so. As a result, individual opportunity sales arrangements do not give rise to additional investments in fixed assets by Manitoba Hydro. Furthermore, the commitment to supply is of a short-term nature and, in this regard, fundamentally different from the commitment to either domestic or long-term firm export customers. Finally, the ability to make opportunity sales does not follow immediately from the existence of in-service facilities and is also dependent upon water flows[70].

[67] PUB/MH I-12 b); PUB/MH II-25 c) and CAC/MSOS/MH II-3 c)
[68] CAC/MSOS/MH I-16 a)
[69] PUB/MH II-25 c), page 2
[70] MIPUG/MH II-1 b)

Overall, the Manitoba Hydro's proposal to include two export classes in its cost of service methodology is reasonable, as there are significant differences between the obligations Manitoba Hydro is undertaking to service firm versus opportunity exports. In the case of Firm Exports, the obligation includes a commitment to provide the system capacity and capability to deliver the contracted quantities over a period of time that will generally extend into Manitoba Hydro's capital planning horizon and therefore could impact on future investment requirements. In contrast, Opportunity sales represent commitments of a short-term nature that will tend to have no impact on future investment requirements and impact only current system operations and spending.

5.3.2 Determination of Firm versus Opportunity Export Sales

For purposes of the Prospective Cost of Service Study (PCOSS06), Manitoba Hydro has split the projected export volumes between Firm and Opportunity sales based on the proportions of forecast surplus energy available over the next five years (2006/07 to 2010/11) to support Firm versus Opportunity sales[71]. The use of the five year period serves to provide some stability to the cost of service methodology while still reflecting system conditions and sales opportunities applicable in the near term. Also, Manitoba Hydro's exclusion of 2005/06 data on the basis that it represents a unique set of operating conditions[72] is also reasonable. The resulting split between Firm and Opportunity Exports incorporated into PCOSS06 was Firm – 54.77% versus Opportunity – 45.23%.

5.3.3 Directly Assignable Export Costs

Under Manitoba Hydro's Current Method the following costs are directly assigned to exports:

- 100% of Purchased Power costs[73]

[71] Appendix 11.1, page 21 and CAC/MSOS/MH II-4 d) & e)
[72] CAC/MSOS/MH I-16 c)
[73] CAC/MSOS/MH I-14 b)

- 50% of the Fuel Costs of Brandon GS and CT[74],
- 50% of Brandon Water Rights[75],
- A share of Water Rental fees equal to the ratio of exports served by hydraulic relative to total hydraulic generation[76],
- A share of Land Rentals for hydraulic generating stations, LOTW Control Board and Lac Seul Operating and Maintenance equal to the Water Rentals share[77],
- 100% of TD Transmission Charges which include MISO membership and legal fees and MAPP membership fees[78], and
- Transmission charges for exports[79].

Table 7 sets out the PCOSS06 costs associated with each.

TABLE 7

COSTS DIRECTLY ASSIGNED TO EXPORTS
BASED ON MANITOBA HYDRO'S CURRENT METHOD

Cost Element	**Cost** ($k)
Purchased Power	50,137.0
Brandon Fuel	8,133.0
Brandon Water Rights	2.4
Water Rentals	25,702.7
Land Rentals, LOTW & Lac Seul	290.8
Market, Regulatory & Legal Fees	5,763.0
Transmission Charges	17,040.0
Total	107,068.9

SOURCE: PUB/MH I-15

Purchased Power

[74] CAC/MSOS/MH I-14 a)
[75] CAC/MSOS/MH II-5 b)
[76] CAC/MSOS/MH I-14 a)
[77] CAC/MSOS/MH II-5 b)
[78] CAC/MSOS/MH II-5 c)
[79] CAC/MSOS/MH II-5 b)

Under the Current Method, the assignment of all purchased power costs to exports is based on Manitoba Hydro's claim[80] that import energy costs to support domestic load are almost entirely avoidable except under drought conditions. Under the Recommended method, purchased power costs all continue to be attributed to exports and 45.23% of their costs are directly assigned to the Opportunity Export class. The remaining 54.77% is included in the Generation costs that are allocated to Domestic customer classes and the Firm Export class.

With the distinction now being made between Firm and Opportunity exports, the question arises as to the appropriate treatment of purchased power. Purchased power transactions are required for two reasons: a) economics and b) energy security. As noted above, during most years purchased power arrangements are made primarily for economic reasons and, in this context, support opportunity-type sales. Purchased power arrangements also underpin Manitoba Hydro's available dependable energy[81] which supports Manitoba Hydro's Firm Export contracts. However, it does not appear that there are any costs associated with such contracts included in the revenue requirement[82]. On the other hand, purchased power can be and is used to meet firm export commitments in lieu of operating Manitoba Hydro's thermal units when it is cheaper to do so. As a result, during years when water flows are high, purchased power costs are likely to be incurred entirely to support opportunity sales. During lower water periods purchases will used to also support firm export sales and, during drought conditions, purchased power will be used to support both firm exports and domestic loads.

However, the PCOSS is based on median water conditions[83] and it appears that for the near-term the amount of surplus hydro available under median flow conditions will be more than sufficient to meet domestic and firm export requirements[84]. Therefore,

[80] PUB/MH I-24 d)
[81] PUB/MH I-22 a)
[82] See PUB/MH I-15
[83] Appendix 11.1, page 29
[84] This conclusion is based on a comparison of the energy available to for Opportunity sales (per Appendix 11.1, page 21) and the dependable energy provided by Manitoba Hydro's thermal resources (PUB/MH I-22 a).

applying the same principles as used in Current Method (i.e., consider the role of purchases in a typical year) would suggest that all purchased power costs should be attributed to the Opportunity Export class.

Wind power purchases are also included as purchased power, despite the fact they are purchased from domestic sources. Such purchases do contribute to dependable energy[85] and, to a significantly lesser extent, capacity reserves[86]. As a result, it would be reasonable to track these costs separately and assign them to both Firm and Opportunity exports. In this regard, the 55%/45% split does not "track" the relative cost responsibility of the two classes but does represent a reasonable assignment of what is currently a fairly small dollar item (relative to total generation costs or export revenues).

Finally, Manitoba Hydro has noted that during periods of drought such as 2002/04 imports were heavily relied upon to support reservoir storage and purchased energy was used to firm export sales[87]. The net effect is that over the last 10 years as much as 60% of purchased power costs were incurred to serve domestic load[88]. The implications are that the direct assignment of purchased power entirely to exports would have to be reconsidered if the COSS was to be performed using the actual results for a year with drought-like water flow conditions[89].

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[85] PUB/MH I-22 a)
[86] RCM/TREE/MH II-35 b)
[87] PUB/MH I-24 d) and CAC/MSOS/MH II-10 a)
[88] PUB/MH I-9a), page 2
[89] Note: Manitoba Hydro does typically prepare/submit a COSS based on actual data as part of a GRA.

Brandon Fuel Costs and Water Rights

Manitoba Hydro states that the assignment of 50% of Brandon GS and CT fuel costs and water rights to exports is based on a long standing practice and reflects the fact that the plant is operated to support both export sales and domestic load[90]. However, neither the PCOSS filed in the Status Update nor the one filed with the 2004 Rate Application appear to have included any thermal fuelling costs in the cost of exports[91]. This apparent inconsistency should be clarified during the proceeding.

In the Recommended Method, 45.23% of the 50% of Brandon fuel and water rights "attributed" to exports is directly assigned to the Opportunity Export class and the remaining 54.77% is included in the Generation costs that are allocated to Domestic customer classes and the Firm Export class.

Given the creation of two export classes, the question arises as to whether and how these costs should be split between the Opportunity and Firm exports. The original role of the coal-fired unit 5 at Brandon GS was to support domestic requirements. However, since the mid-1990's it has been operated to support export sales as well as domestic load during drought periods[92].

The construction of the two new Brandon gas turbines was justified on the basis that they would firm up export sales[93]. However, the plant is also available to support domestic reliability during low water periods and the units could also be used to support Opportunity sales. Their operation for the later purpose depends very much on the price of gas and, currently, it is rarely economic to operate them for Opportunity sales[94].

The changing circumstances associated with stations such as Brandon and the fact that exports are considered in a different context than domestic loads for both planning and

[90] MIPUG/MH II-2
[91] Manitoba Hydro's 2004 GRA: CAC/MSOS/MH I-109 d) and Status Update Filing: Appendix 12, Schedule B-19
[92] MIPUG/MH II-2
[93] PUB/MH II-8 a)
[94] MIPUG/MH II-2

operating purposes highlight the difficulty in attributing costs to an export class. The 50/50 split of Brandon fuel costs between exports and domestic loads does not appear to be based on any analysis regarding the cost responsibility of the two types of loads but rather is based on an attempt to recognize that both types of loads can benefit from the operation of the station[95].

However, there appears to be an inconsistency between the approach taken for Brandon GS & CT fuel costs versus Purchased Power. The approached adopted for Purchased Power is based on the role the purchases will fill during a typical (i.e., normal) year without consideration as to the role and benefits purchases play during low water years. In contrast, the assignment of Brandon's fuel costs on a 50/50 basis appears to be done in an effort to recognize that the operation of station will provide support for domestic loads during low-water periods. For consistency purposes, it would be appropriate to adopt a common approach for both types of costs.

There are merits and shortcomings to both approaches:

- Using the approach as applied to Purchased Power is likely to capture Manitoba Hydro's operating circumstances for most years. However, it may have to be revised if a particular COSS is based on a year with low water conditions.
- Using the approach as applied to Brandon means the same approach can be applied in all years. However, the results will not be reflective of how the system operates most years.

There does not appear to be a truly compelling case for adopting one approach over the other. At this point in evolution of Manitoba Hydro's COSS it would reasonable to adopt the approaches recommended by Manitoba Hydro for each cost item and request that the Company give the issue further consideration. In the alternative, if stakeholders (including the MPUB) require an immediate resolution the issues, then it is recommended that the approach as applied to Purchased Power be adopted for both cost items.

[95] CAC/MSOS/MH I-14 b)

Water Rentals and Related Costs

Under the Current Method, the exports served by hydraulic generation are identified as the difference between the total energy exported and the energy associated with purchases and half of Brandon's generation. Exports are then allocated a share of Water Rentals and other related costs associated with the operation of hydraulic facilities based on the ratio of the exports served by hydraulic generation to total hydraulic generation[96]. Under the Recommended Method, the costs to be assigned to exports are identified in a similar fashion and then 45.23% of the costs are assigned to the Opportunity Export class. The other 55.77% are assigned to the Firm Export class.

The Recommended Method is a reasonable way of assigning water rental costs. However, should the treatment of Purchased Power costs or Brandon GS fuelling costs be changed then the "calculations" would have to be adjusted accordingly.

TD Transmission Charges

TD Transmission charges include charges for MISO membership and legal fees, and MAPP membership fees[97]. Under Current Method, 100% of the associated costs are assigned to exports. Under the Recommended Method, the 100% of costs is split between Firm and Opportunity Exports on a 55.77%/45.23% basis. This same approach also applies to NEB fees and charges.

These various fees support Manitoba Hydro's participation in MAPP and MISO. As a result, they can be viewed as being associated with both exports and purchases. However, under Manitoba Hydro's Recommended Method all purchase costs are assigned to exports and therefore the proposed treatment is reasonable. Should the treatment of purchases change in the future then the assignment of TD Transmission Charges would need to be revisited.

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[96] CAC/MSOS/MH I-14 a)
[97] CAC/MSOS/MH II-5 c)

Transmission Charges for Export

These costs represent the purchase of transmission services to facilitate exports and, under the Current Method; they are all assigned to exports sales[98]. Under the Recommended Method the costs are split between Opportunity and Firm exports on a 45.23% / 55.77% basis.

Manitoba Hydro has indicated that it uses purchased transmission services to support the sales of both Firm and Opportunity Exports[99]. As result, the proposed assignment of the costs to both classes is appropriate. The 45/55 split does not necessarily track the relative cost responsibility of the two export classes. However, it is a reasonable split and sharing of the associated costs.

Other Costs

Over and above the cost items that Manitoba Hydro has directly assigned to exports, there are couple additional items that need to be addressed. First, Manitoba Hydro has identified a number of internal activities that are associated with its involvement in markets outside of the Province[100]. The annual amount involved totals roughly $7.3 million which Manitoba Hydro has not included in the costs to be directly assigned to exports, arguing the amounts involved are not significant.

However, both the $7.3 M and its individual components are in the same order of magnitude as some of the cost elements Manitoba Hydro directly assigns to exports under the Current Method. As a result, it seems reasonable to also include these costs in with those to be directly assigned. Furthermore, these costs are similar to the TD Transmission costs in that they support Manitoba Hydro's involvement in both the

[98] CAC/MSOS/MH II-5 b)
[99] CAC/MSOS/MH I-16 e) & f)
[100] Appendix 11.1, page 29

import and export markets. Therefore, a reasonable approach is to assign them in a similar manner: 45.23% to Opportunity Exports and 55.77% to Firm Exports.

Second, Manitoba Hydro has indicated that Selkirk's fuel costs are not considered to be attributable in any way to exports. However, there is no clear explanation for this position and the matter should be pursued further with the Company[101].

Finally, Manitoba Hydro does not directly assign any Ancillary Service costs to exports, even though such services are required to support transmission. However, Manitoba Hydro has justified their exclusion on the basis that such services are primarily in place to support domestic load and, in the case of exports, only two of the six services need to be purchased from the vendor. The other four services can be provided in-house by the purchaser or purchased from another external party[102].

5.3.4 Treatment of Interconnections

Under Manitoba Hydro's Recommended Method, Transmission costs are categorized as between interconnection lines and domestic lines[103]. This distinction was first recommended in the NERA Report[104] and is meant to distinguish between domestic transmission investment related to serving peak loads and that justified because it reduced energy losses or facilitates energy exports as well as supporting domestic loads. Under the Recommended Method both Interconnection and Domestic lines are allocated to the Firm Export and Domestic customer classes. The difference is that Interconnection Lines are allocated based on energy whereas Domestic Lines area allocated based on demand (2 CP).

Definition and Costing of Interconnection Lines

[101] CAC/MSOS/MH II-9 c) and MIPUG/MH II-2
[102] CAC/MSOS/MH I-19 c)
[103] Appendix 11.1, page 29
[104] Pages 39-40

The classification of a transmission line as an “interconnection” is based on whether the line crosses provincial boundaries[105]. In each case the starting point of the interconnection line is at the last substation that transforms the voltage to that which is fed to the line[106]. The associated sub-station is also deemed to be export-related if servicing of the line is the station’s primary function[107]. The capital-related and operating costs of such lines (and stations) are separately identified in Manitoba Hydro’s financial systems[108]. Interest, net income and capital tax are allocated based on the value of the assets attributed to interconnection lines[109]. Finally, the common costs associated with transmission (e.g. R&D, Planning and System Control costs) are allocated between Domestic and Interconnection lines based on the balance of the transmission costs that have been attributed to each[110]. Overall, the costing approach used by Manitoba Hydro is reasonable and fairly accurate, in large part due to the alignment of the COSS definitions with definitions used in Manitoba Hydro’s financial reporting system.

It should be noted that interconnection lines are not solely used to transmit energy across Manitoba’s provincial boundaries. There are also domestic customers served off some of these same lines[111]. However, any attempt to further refine the definition and costing is likely to require a significant amount of estimation. In contrast, the domestic loads served are likely to be small relative to the inter-provincial volumes involved. As result, the proposed definition should be considered reasonable.

[105] PUB/MH I-23
[106] CAC/MSOS/MH II-30 a)
[107] PUB/MH I-23
[108] PUB/MH I-34 a) and CAC/MSOS/MH I-12 f) & h)
[109] PUB/MH II-26 b)
[110] PUB/MH II-26 a)
[111] CAC/MSOS/MH I-12 d)

Allocation of Interconnection Line Costs

The objective behind separating out Interconnection Lines is to recognize that such lines are also used for exports as well as domestic loads. Furthermore, in considering the use of inter-ties for exports and domestic load support, the focus is more on overall energy transfer capability as opposed to capacity at peak times. The result is that even though Domestic and Interconnection Lines are both allocated to the same customer classes, the allocation differs in each case[112].

In the case of Interconnection Lines, the associated costs are allocated to the Firm Export and Domestic customer classes based on the total annual energy requirement of each class. The use of total annual energy to allocate the costs of Interconnection Lines between individual Domestic customer classes is reasonable. Indeed in most years, the major benefits to domestic loads from inter-ties (apart from export revenues) is associated with the reserve support they provide (e.g., an alternative source of supply in the event of a major transmission failure associated with the delivery of northern generation)[113] and the ability they create for Manitoba Hydro to enter into Diversity contracts with neighbouring jurisdictions.

However, annual energy is less effective as a cost driver in allocating Interconnection Lines costs between Domestic Load and the Export Classes. The primary purpose of all Manitoba Hydro's Transmission System (including its inter-ties) is to ensure the reliability of supply for domestic customers[114]. While additional investments have been made in Transmission facilities to facilitate exports, these investments have typically been at less than the average cost of the overall facilities[115]. On the other hand, while all Firm Exports would typically make use of the interconnection lines; inter-ties are not used to actually supply all domestic load. Therefore, the use of energy (or for that

[112] PUB/MH II-19
[113] PUB/MH I-34 c)
[114] PUB/MH II-20 a)
[115] PUB/MH I-24 l)

matter demand) to allocate the cost of inter-ties as between Firm Exports and Domestic Loads will not effectively "track costs".

An allocation between Domestic classes and Firm Exports based on energy simply recognizes that both type of loads rely on these facilities and represents a reasonable compromise in absence of better information[116]. Similarly, the exclusion of Opportunity exports from the allocation recognizes that while Firm exports obligations represent a commitment regarding the availability of interconnection capability and could impact on future planning, Opportunity Sales have no similar long-term implications[117].

As a final observation (and one that also applies to the next two sections), Manitoba Hydro has chosen to include and treat the Firm Export class on a comparable basis with other Domestic classes for purposes of allocating costs and at the same time exclude Opportunity Exports from any such allocation. As already noted several times, Firm Exports are not included in Manitoba Hydro's planning processes in the same manner as Domestic loads and do not carry the same degree of reliability as Domestic Loads on day to day basis. Treating Firm Exports in a similar fashion to Domestic loads and allocating them a full share of embedded costs, while excluding Opportunity sales should be viewed as compromises that, when taken together, tend to balance each other off.

5.3.5 Allocation of Domestic Transmission Lines

Under the Recommended Method, Domestic transmission lines are allocated to the Firm Export class and the Domestic customer classes using the 2CP factor, the same methodology as applied to total Transmission costs under the Current Method[118]. Again, the Opportunity Export class does not attract any of the embedded costs associated with Domestic Transmission. The difference in treatment of the two classes

[116] PUB/MH I-24 l); PUB/MH I-13, page 2 and CAC/MSOS/MH I-9 c.7) & c.8)
[117] PUB/MH I-24 l)
[118] Appendix 11.1, page 20 and PUB/MH I-24 i)

recognizes that Firm Exports represent an obligation on domestic transmission facilities that could impact future transmission planning and costs. In contrast, the short-term obligations created by Opportunity sales do not impact on future costs and are committed to only if sufficient surplus capacity exists. Admittedly, the potential for Opportunity sales may have influenced the costs incurred for Domestic Transmission. However, ignoring such implications is balanced by the fact that the Firm Export class attracts a full share of costs which likely overstates the costs actually incurred to accommodate such sales[119].

Overall the Recommended Method represents a practical approach and a reasonable compromise given the available information.

5.3.6 Allocation of Embedded Generation Costs

The actual method used to allocate generation costs has already been reviewed above in Section 4.3. The focus of this section will be on the inclusion of Exports in the allocation and the treatment of that portion of directly assignable costs attributed to Firm Exports.

The Recommended Method includes the Firm Export class in the allocation of both demand[120] and energy-related Generation costs on an equal basis with the various Domestic customer classes. In contrast, the Opportunity Export class is excluded from the allocation. This approach is similar to that used for Domestic Transmission Lines and the rationale is similar as well:

- Manitoba Hydro has, in the past, considered firm export sales when determining if there is a case to advance new generation projects needed to meet domestic load and, on this basis it would be reasonable to attribute a portion of the costs incurred to firm export sales. On the other hand, Manitoba Hydro has not committed to any

[119] PUB/MH I-24 l)
[120] The demand-related Generation costs represent the offset for the Curtailable load credit. See PUB/MH I-24 h)

such projects simply to facilitate firm export sales[121]. This would suggest that what should be attributed to such exports are the incremental capacity and system operations costs, which are likely to be less than the average cost of the associated facilities[122]. However, it is impractical to identify such costs from the financial information supporting the revenue requirement underlying a cost of service study. Treating Firm exports as equivalent to domestic load recognizes the capacity obligations associated with such sales but likely overstates the generation cost that are caused by such sales.

- The potential revenue from opportunity sales is also factored into decisions regarding whether or not to advance the in-service date of generation facilities needed to meet domestic load requirements[123] and into the design of facilities[124]. However, as with firm exports the incremental impact on cost is less than the average cost of the facilities concerned. Not allocating any embedded cost to Opportunity sales likely understates the generation cost caused by such sales but recognizes the lower reliability and the lack of long-term capacity obligations associated with such transactions.

Included in the Embedded Generation costs to be allocated to customer classes is the 55% portion of the Directly Assignable export costs that were attributed to Firm Exports. In each case, the costs are allocated to both the Firm Export and various Domestic classes. For many of the cost elements an argument could be made that the remaining 55% should be only attributed to Firm Exports. Examples of this would include Transmission Charges for exports and External Market and NEB fees. In addition, the COSS methodology could attempt to flow the Brandon and Hydraulic operating costs and any Purchased Power costs attributed to Firm Exports directly through to that class.

However, the overall approach adopted for Firm Exports is that it should be treated similar to Domestic customer classes for the purpose of allocating Generation and

[121] MIPUG/MH II-1 b)
[122] PUB/MH II-8 a) and PUB/MH I-24 l)
[123] MIPUG/MH II-1 b)
[124] PUB/MH II-8 a)

Transmission costs. The introduction of any departure from this approach opens somewhat of a Pandora's Box and begs the question as to what other adjustments/departures should be included. Furthermore, the direct assignment of a share of Water Rentals, Brandon fuelling costs or Purchased Power costs to Firm Exports would require an adjustment in the allocation of the remaining embedded generation costs. It is not readily apparent how such adjustments could be accomplished. Manitoba Hydro has indicated that its Recommended Method is subject to improvement as the methodology and data sources are refined in future. This may be area for future consideration[125]. However, for now, the Manitoba Hydro approach is a reasonable starting point.

5.3.7 Comparable GSL Results

In Board Order 7/03, the MPUB suggested that the allocation methodology used for the Firm and Opportunity Export classes should be similar that applied to the General Service and Interruptible GSL classes respectively[126].

Table 8 compares the total cost allocated to the GSL > 100 kV (non-curtailable) class and the Firm Export class.

[125] PUB/MH I-24 a)
[126] Board Order 7/03, page 102

TABLE 8

ALLOCATION OF COSTS TO
GSL>100 (Non-Curtailable) Versus FIRM EXPORTS
(cents/kWh)

	GSL>100 (Non-Curtailable)	Firm Exports
Generation	3.24	3.21
Transmission	0.67	0.80
Customer Service	0.04	n/a
Distribution Plant	0.00	n/a
Total	3.96	4.01

SOURCE: PUB/MH II-25 a)

In principle, one would expect Firm Exports to attract less Generation and Transmission costs than firm Domestic load – as the reliability associated with Firm Exports is lower and the facilities were put in-service first and foremost to service Domestic load. However, on a per kWh basis, the costs attributed to Firm Exports slightly exceed those associated with the GSL>100 kV (non-curtailable) class. The source of the higher costs for Firm Exports is attributable to higher unit transmission costs offset, to some extent, by slightly higher Generation cost for the GSL>100 kV class and the fact the GS > 100 kV class also attracts some customer service related costs. In fact, since the same allocation methodology is used to allocate Generation and Transmission costs to both classes, the differences in the results for Generation and Transmission costs are likely attributable to differences in the annual load shapes for the two which impact on both:
a) the weighted energy cost used to allocate most generation costs, and
b) the 2CP annual load factor which will impact on the resulting per kWh allocation of domestic transmission costs[127].

Table 9 similarly compares the total costs allocated to GSL>100 kV (curtailable) versus Opportunity Exports, on a per kWh basis.

[127] Note: The allocation factors provided in Appendix 11.3 do not provide the necessary break down between curtailable and non-curtailable GSL>100 kV load to actually demonstrate this.

TABLE 9

ALLOCATION OF COSTS TO
GSL>100 (Curtailable) Versus OPPORTUNITY EXPORTS
(cents/kWh)

	GSL>100 (Curtailable)	**Opportunity Exports**
Generation	3.05	1.20
Transmission	0.64	n/a
Customer Service	0.02	n/a
Distribution Plant	0.00	n/a
Total	3.72	1.20

SOURCE: PUB/MH II-25 a)

In this case there is a significant difference between both the Generation and Transmissions costs allocated to the two classes – with the costs allocated to the Opportunity Export class being less in each case. However, the differences are understandable given the material difference in the service being provided. In the terms of Generation, the service provided to Curtailable loads is the same as for domestic customers – except for the contractually limited curtailments that can be initiated by Manitoba Hydro[128]. In contrast, Opportunity sales are short-term commitments (generally a month or less) that are only made when there is clearly sufficient generation resource capability available to allow the arrangements to proceed.

Similarly, in the case of transmission, Curtailable loads are served by firm transmission[129]; whereas Opportunity Exports are only made if there is sufficient surplus transmission capability to facilitate the sale. This leads to Curtailable load being allocated a share (albeit a lower share) of fixed generation costs and a full share of

[128] PUB/MH II-25 c)
[129] PUB/MH II-25 c). Also, it should be noted that if firm transmission service was not planned for and provided then the curtailments would likely be have to exceed the contractual limitations.

Transmission costs. In contrast, Opportunity costs do not attract any transmission costs and only variable costs associated with Generation[130].

While it could be argued that Opportunity Exports are carrying less than their fair share of fixed costs relative Domestic loads; the opposite argument could be made in the case for the Firm Export class. As noted a number of times in the preceding sections, it is not practical to expect the COSS methodology to capture the differences in the costs of Firm and Opportunity Exports on the one hand and Domestic load on the other hand from a cost causality perspective. Rather the Recommended Method should be viewed as producing a reasonable sharing and balancing of Generation and Transmission costs between Domestic and Export loads[131].

5.3.8 Allocation of Net Export Revenues

Under Manitoba Hydro's Recommended Method Net Export Revenues are calculated as Gross Export Revenues less the costs directly assigned to Opportunity Exports and the costs allocated to Firm Exports[132]. The calculation of Net Export Revenues is summarized in Table 10.

[130] PUB/MH II-21
[131] See also PUB/MH II-13, page 2
[132] Gross export revenues are also reduced by the amount required to fund the uniform rate policy. See Appendix 11.1, page 14.

TABLE 10

RECOMMENDED METHOD
NET EXPORT REVENUE CALCULATION

Gross Export Revenues:	$547.4 M
Less:	
- Uniform Rate Adjustment	16.8
- Directly Assigned to Opportunity Exports	48.4
- Allocated to Firm Exports	196.3
Net Export Revenues	$285.9 M

SOURCE: Appendix 11.1, page 19

Net Export Revenues are then allocated to the Domestic customer classes (including Diesel) based on the total allocated costs attributed to each class for all COSS functions. The major changes from the Current Method are:

a) The inclusion of the allocated costs of all functions in the allocation base for Net Export Revenues, instead of just Generation and Transmission costs, and
b) The inclusion of Diesel Communities in the customer classes that are allocated the Net Export credit, as opposed to just grid-connected customer classes.

There are a couple of key considerations that need to be taken into account when allocating net export revenues to customer classes.

The first of these is that export revenues rely upon the use of generation and transmission facilities that were constructed primarily for the purpose of supplying domestic customers. This point was the basis for the Current Method's allocation of Net Export Revenues to the domestic customer classes based on their allocated Generation and Transmission costs. It reflects the principle that the domestic customers who were paying for the Generation and Transmission facilities should be the ones who benefit from incremental revenues generated through the use of the assets[133].

However, at the time that this principle was first applied export revenues were primarily from Opportunity sales and the prices received were, on average, considerably less than either the average cost of the facilities being utilized or the rates paid by Domestic customers. This meant that increased usage of these assets by Domestic customers that diverted energy from export sales would increase revenues and benefit all customers. In this context allocating the benefit of increased exports to customers using the same facilities was reasonable.

The second consideration is that by the time of the 2002 Status Update circumstances had changed. As Table 11 illustrates, export revenues have grown significantly in terms of their overall value and the per kWh revenues from exports had increased to the point where they were higher than the unit revenues from domestic loads.

TABLE 11

HISTORICAL DOMESTIC AND EXPORT SALES

	Sales (GWh)		Revenues ($M)		Average Revenues (per kWh)		Export % of
Year	Domestic	Exports	Domestic	Export	Domestic	Export	Total Rev
1994	15,065	9,103	686	232	$0.046	$0.025	25.27%
1995	14,797	9,425	684	253	$0.046	$0.027	27.00%
1996	15,856	9,659	735	246	$0.046	$0.025	25.08%
1997	16,124	11,499	750	268	$0.047	$0.023	26.33%
1998	15,949	13,567	739	297	$0.046	$0.022	28.67%
1999	16,331	11,404	748	326	$0.046	$0.029	30.35%
2000	15,820	10,868	737	376	$0.047	$0.035	33.78%
2001	16,698	12,065	781	480	$0.047	$0.040	38.07%
2002	16,958	12,091	786	588	$0.046	$0.049	42.79%
2003	18,953	9,459	875	463	$0.046	$0.049	34.60%
2004	19,323	4,395	918	351	$0.048	$0.080	27.66%
2005	19,781	9,569	939	554	$0.047	$0.058	37.11%

SOURCE: 2004/05 Annual Report (for 1996 to 2005)
2002/03 Annual Report (for 1994 to 1995)

133 RCM/TREE/MH I-11 a)

There are two major implications from these changed circumstances. The first is that if available generation is diverted from exports through an increase in domestic loads, the net effect would be an increase in costs for all customers[134]. As discussed in Section 3, the purpose of a cost of service study is to allocate the various components of a utility's revenue requirement to customers using allocation factors that reflect the "drivers" underlying the costs. Under the Current Method (and the Recommended Method) Generation and Transmission costs are allocated to customers based on their use of the functions as measured by their loads (i.e., energy and demand). Allocating the Net Export Credit to customers on the same basis suggests 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 will lead to reduced export sales and increased costs (and rates) overall.

The second is that, given the materiality of the export revenues, the Net Export Revenue credit represents over 40% of the generation and transmission costs allocated to each Domestic Customer class. However, in terms of total costs,
the impact of the Net Export Credit varies widely across customer classes from roughly 24% in the case of Residential to almost 40% in the case of GSL.

TABLE 12

PCOSS06 RESULTS - CURRENT METHOD

	Total Costs ($k) Pre-Export Credit	Total G&T ($k) Pre-Export Credit	Total ($k)	Export Credit % of Total Costs	% of G&T Costs
Residential	605,679	338,518	144,860	23.92%	42.79%
GS Small	258,777	171,298	72,161	27.89%	42.13%
GS Medium	196,833	147,846	62,740	31.87%	42.44%
GS Large	356,412	328,330	142,082	39.86%	43.27%

SOURCE: PUB/MH II-24
Appendix 11.1, page 37

[134] PUB/MH I-26, page 2

The net result is that the treatment of net export revenues under the Current Method has a significant effect on the total costs allocated to each customer class and the effect varies widely across customer classes. This result is a function of both the way net export revenues are calculated and as well as the way they are allocated to customer classes. Under the Current Method the only costs attributed to exports are a portion of variable/operating costs. The effect is that net export revenues are a significant portion of gross export revenues (over 75% in PCOSS06, even after allowing for the uniform rate adjustment).

In the COSS changes proposed as part of the 2002 Status Update, Manitoba Hydro sought to address these issues by proposing a more neutral allocation of net export revenues based on the total costs allocated to each customer class (as opposed to just generation and transmission costs). However, it was rejected by the MPUB[135]. The MPUB expressed the view that previously adopted cost causation principles still applied and that the calculation of net export revenues did not include many of the direct and indirect costs associated with export power sales. In order to address this later concern the MPUB directed Manitoba Hydro to create and include in its cost of service methodology both a Firm and an Opportunity Export class.

Manitoba Hydro's Recommended Method does include both a Firm and an Opportunity Export Class and attributes significantly more costs to exports than the Current Method. This can readily be seen by the reduction in the Net Export Credit from $423.6 M to $285.9 M[136]. In doing so, the calculation of Net Export Revenues recognizes more explicitly the fact that export revenues are derived from the use of Generation and Transmission and, thereby, captures to a greater extent the first consideration discussed above and the associated principle of cost causality as adopted in the mid-1990's. The allocation of the resulting net export revenues using a more neutral basis (i.e., total allocated costs as opposed to just allocated Generation and Transmission costs) then seeks to address the concerns regarding the perverse cost causation

[135] Board Order 7/03, page 97
[136] Appendix 11.1, pages 37 & 40

signals and cost of service results created by the Current Method's treatment of net export revenues. Overall the Recommended Method represents a balanced approach to addressing the various considerations involved.

5.3.9 Alternatives

As requested by the MPUB[137], as well as its Recommended Method, Manitoba Hydro has also present COSS results based on NERA's recommendation and a Vintage-based approach to identifying generation cost related to exports, as suggested by RCM/TREE.

NERA Recommendations

The only major[138] difference between Manitoba Hydro's Recommended Method and the NERA Method is the Recommended Method's separation of the Export Class into Firm and Opportunity sub-classes versus the use of a single Export class in the NERA Method[139]. Under the NERA Method, the entire export class is assigned Generation and Transmission costs on the same basis as Domestic Customers. In doing so, the NERA Method fails to account for the fundamental differences between Firm and Opportunity sales as discussed in the preceding sections. In this regard, the Recommended Method should be viewed as an improvement on the NERA recommendations. Manitoba Hydro has noted that its Recommended Method was discussed with NERA and that they have concurred that the modifications are appropriate[140].

[137] Board Order 101/04, page 32
[138] There are minor differences between the NERA methodology as presented in its February 2004 Report and the NERA Method as presented by Manitoba Hydro. These include Manitoba Hydro's incorporation of the Uniform Rate Adjustment, the use of SEP data as opposed to Platt's data as a proxy for marginal costs and a refined methodology for identifying export lines. All of these are better characterized as refinements than fundamental differences.
[139] PUB/MH I-31 b)
[140] PUB/MH I-33 d)

Generation Vintaging

Under the Generation Vintaging Method, the “less expensive” Winnipeg River generating plants are assumed to only serve domestic customers. The higher cost generation is assumed to serve exports and the residual domestic requirements[141]. As presented by Manitoba Hydro, the Vintaging Method utilized a singe export class, similar to the NERA Method.

As expected the approach increases the Generation and Transmission costs allocated to exports. However, the increase is only 4%[142] and the resulting impact on the Revenue to Cost ratios for most customer classes is less than 0.5 percentage points[143] relative to the NERA Method. Manitoba Hydro has also expressed some reservations[144] about the fact that what is considered “low cost” generation could change over time as expenditures are made to upgrade various facilities. Overall, it would appear that the additional effort to implement and maintain the currency of the method may not be warranted given that it does not yield materially different results.

5.3.10 Conclusions

- There are conflicting considerations and determinations of “cost causation” that must be balanced in the treatment of export revenues in the Cost of Service Methodology.
- The objective in creating an export class is not to determine the actual costs of exports for purposes of setting export prices or the economics of export sales but rather to arrive at a fair allocation of costs to domestic customers. Indeed, it is unlikely that the differences between exports and domestic sales (in terms of the commitment to serve and their impact on Manitoba Hydro’s planning and costs) can be accurately captured by the COSS methodology.

[141] Appendix 11.1, pages 24-26
[142] PUB/MH II-24
[143] See Appendix 11.1, pages 43 & 46
[144] Appendix 11.1, page 26

- The creation of an export class (or classes) allows the Cost of Service methodology to more formally consider the costs that should be associated with exports prior to the determination of net export revenues. This can help ensure that appropriate recognition is given to the fact that export revenues arise from the use of transmission and generation capacity. Furthermore, the creation of both a Firm and an Opportunity Export class is appropriate and recognizes that there are fundamental differences between the two types of sales in terms of the associated generation and transmission commitments.
- Direct assignment to Opportunity Exports of 45% of the cost traditionally assigned to exports under the Current Method is reasonable for most of the cost elements concerned. However, in the case of Purchased Power and Brandon GS further refinement is required. For out of province Purchased Power costs, it could be more appropriate to assign them all to Opportunity Exports. In the case of Brandon GS fuel costs, there is a need to further clarify the basis for the proposed treatment.
- The splitting of Transmission costs between Domestic and Interconnection lines and the allocation of Interconnection lines based on annual energy represents an improvement in the allocation of transmission costs among Domestic customer classes, as it recognizes the different cost drivers behind domestic versus interconnection lines.
- The use of annual energy to allocate Interconnection lines between Domestic customers and Firm Exports, while excluding Opportunity Exports, is a reasonable approach to determining the transmission costs that should be attributed to exports.
- Similarly, the Recommended Method's allocation of Generation costs to Domestic customers and Firm Exports is a reasonable approach to determining the generation cost that should be attributed to exports.
- The allocation of Net Export Revenues based on the total costs allocated to each Domestic customer class produces reasonable and balanced results across the various customer classes. Continuing to use the same cost drivers to allocate Net Export Revenues as are used to allocate Generation and Transmission costs would be inconsistent with today's reality where increased domestic use leads to reduced net export revenues and higher costs for all customers.

6 OTHER ISSUES NOTED

6.1 Uniform Rate Adjustment

In Board Order 101/04, Manitoba Hydro was directed to "allocate the cost of uniform residential rates as a first charge on net export revenue"[145]. For purposes of preparing PCOSS06, Manitoba Hydro calculated a separate uniform rate reduction percentage for each sub-class (zone) based 2002 data and then applied the result to the projected revenues at current rates for each zone and class of use[146]. The result, when summed across all classes and zones, is $16.7 M.

Manitoba Hydro has indicated that on a going forward basis the Corporation is no longer supporting the zonal distinctions and that the accuracy of the records regarding revenues by zone will erode over time[147]. As result, it proposes that for future studies the calculation will be based on a singe percentage by class[148]. The proposed approach is reasonable. There is some confusion in the material presented as to what the percentage adjustment will be for grid-connected Residential customers. At one point, the suggestion seems to be that the percentage will be 3.6% for all Residential use[149], excluding Diesel. Elsewhere, the suggestion appears to be that the 3.6% factor includes Diesel residential customers[150]. This should be clarified with Manitoba Hydro during the proceeding.

Manitoba Hydro also noted that PCOSS06 did not include a uniform rate adjustment for Diesel Community revenues[151]. Based on revenue forecast in PCOSS06 the adjustment would be $67,200, increasing the total uniform rate adjustment to $16.8 M.

[145] Board Order 101/04, page 36
[146] PUB/MH I-6 and CAC/MSOS/MH I-13 a)
[147] PUB/MH I-6
[148] CAC/MSOS/MH I-2 a)
[149] PUB/MH I-6
[150] CAC/MSOS/MH II-31 d)
[151] CAC/MSOS/MH I-13 d)

6.2 Role of Rate Design

Information requests also raised the question as to whether the concerns expressed by Manitoba Hydro regarding the gap that exists between rates and marginal costs (created in part by the Current Method's treatment of export revenues) and the pricing signals thereby created could be addressed through rate design.

As Manitoba Hydro has indicated in response to MIPUG/MH I-15 d), it is possible to implement inverted rates or time of use that better reflect the marginal costs of incremental consumption regardless of the cost of service methodology used. However, such approaches have their limitations and will be restricted in terms of their effectiveness by the overall revenue requirement to be recovered from the class. For example, if marginal costs are significantly higher than average costs then an inverted rate design is limited in terms of how much consumption it can be applied to (i.e., where the cut-off point for the last block of energy use can be set) without significantly distorting the pricing structure for the earlier usage block(s) which are likely to also apply to some customers' incremental consumption.

Furthermore, as discussed in Section 5.3.8, when it comes to the treatment of export revenues there is justification – from a cost of service perspective – for adopting a more neutral approach to allocating net export.

6.3 Marginal Cost of Service Studies

The MPUB staff posed several questions regarding marginal cost of service studies versus embedded cost of service studies[152].

As Manitoba Hydro has noted, most utilities utilize embedded cost of service studies to support the relative allocation of their revenue requirement to customer classes[153]. The

[152] PUB/MH I-1 a) – e)

use of marginal costs is generally reserved for rate design. One of the reasons for this approach is that most utilities rate levels are set so as to recover an approved revenue requirement based on accounting (i.e., embedded) costs. Undertaking an embedded cost of service study requires the utility to justify and defend the cost allocation methodologies in its embedded cost of service study. However, undertaking a marginal cost of service study would require the same utility to not only have a defensible cost allocation methodology but also prepare and defend its estimates of marginal costs. As Manitoba Hydro notes[154] and the Ontario Energy Board concluded[155] there are major practical issues and problems regarding definition and determination of marginal costs. Furthermore, rarely do marginal cost-based rates yield the same revenue requirement as embedded costs and adjustment mechanism must be employed to reconcile the results of a marginal cost of service study with the approved revenue requirement. Again, there are various methods for doing so and judgment is involved. Another reason for most utilities utilizing embedded cost of service studies is that such studies focus on tracking and allocating the costs that were historically incurred which is the basis for their rates. In contrast, the focus of a marginal cost of service study is on tracking the costs that would be incurred if the service were to be planned for today or in the future.

Manitoba Hydro has indicated that it would require significant time and effort to undertake a marginal cost study[156]. At this point, it is not at all clear that the benefits would justify such an effort.

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[153] PUB/MH I-1 a)
[154] PUB/MH I-1 b)
[155] OEB Report HR5, page ix
[156] PUB/MH I-1 c)

APPENDIX A

CV FOR ECS CONSULTANT

William O. Harper

Mr. Harper has over 20 year experience in the design of rates and the regulation of electricity utilities. 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 from1989 to 1995. Mr. Harper 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, and CRTC. He has also appeared before the Manitoba's Public Utilities Board, the Manitoba Clean Environment Commission and Quebec's Régie de l'énergie. Bill is currently a member of the Ontario Independent Electricity System Operator's Technical Panel.

EXPERIENCE

Econalysis Consulting Services- Senior Consultant
2000 to present

- 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).

- Electricity
  - 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*
  - BC Hydro IPP By-Pass Rates
  - WKP Generation Asset Sale
  - BC Hydro Heritage Contract Proposals
  - BC Hydro's 2004/05 and 2005/06 Revenue Requirement Application
  - BC Transmission Corporation – Open Access Transmission Tariff Application - 2004
  - BCTC's 2005/06 Revenue Requirement Application
  - BC Hydro's CFT for Vancouver Island Generation – 2004

- BC Hydro's 2005 Resource Expenditure and Acquisition Plan
- Fortis BC's 2005 Revenue Requirement Application
- 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 Tariffs*
- Hydro Québec – Distribution's 2005/2006 Tariff Application*
- Hydro Québec – Distribution's 2006/06 Tariff Application*
- Hydro Québec – Distribution's 2005-2014 Supply Plan*
- Hydro Québec – Transmission's 2005 Tariff Application*
- 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*

- <u>Natural Gas Distribution</u>
  - Enbridge Consumers Gas 2001 Rates
  - BC Centra Gas Rate Design and Proposed 2003-2005 Revenue Requirement
  - Rate of Return on Common Equity (BCUC)
  - Terasen Gas (Vancouver Island) LNG Storage Project (2004)

- <u>Telecommunications Sector</u>
  - Access to In-Building Wire (CRTC)
  - Extended Area Service (CRTC)
  - Regulatory Framework for Small Telecos (CRTC)

- <u>Other</u>
  - Acted as Case Manager in the preparation of Hydro One Networks' 2001-2003 Distribution Rate Applications
  - 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 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 IESO Technical Panel (April 2004 to Present)

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;
  - monitoring and intervening in other regulatory proceedings;
  - 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.
- Participated in a tariff study for the Ghana Power Sector, which involved the development of long run marginal cost-based tariffs, together with an implementation plan.

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