PRE-FILED TESTIMONY OF
P. BOWMAN AND A. McLAREN
IN REGARD TO MANITOBA HYDRO
2006 COST-OF-SERVICE APPLICATION

Submitted to

The Manitoba Public Utilities Board

On behalf of

Manitoba Industrial Power Users Group

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1.0 INTRODUCTION

This testimony has been prepared for the Manitoba Industrial Power Users Group (MIPUG) by InterGroup Consultants Ltd. (InterGroup) under the direction of Mr. P. Bowman with the assistance of Mr. A. McLaren. MIPUG's current membership and concerns are outlined in Section 1.2. The qualifications of Mr. P. Bowman and Mr. A. McLaren are provided in Attachment D.

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's (Hydro) filed material regarding its 2006 Cost-of-Service Application (Application) that are of interest to industrial customers. In particular, the scope of the review includes matters relating to the proposed cost-of-service study, taking into account normal regulatory review procedures and principles appropriate for Canadian Crown-owned electric power utilities.

The evidence is presented in the following sections:

- Section 2 provides a summary of the Hydro Application and key observations regarding the material filed.
- Section 3 provides an brief overview of issues raised in the current proceeding that may be best addressed outside of the cost-of-service study (COSS).
- Section 4 reviews Hydro's proposed changes to the cost-of-service methodology.

Summaries on specific topics have been provided in attachments to deal with certain technical or background materials in more detail.

1.1 SUMMARY

There are two key issues at hand in the present hearing. The first relates to the need to ensure ratepayers adequately benefit, in terms of stable and attractive cost-based rates, from the investments made in historic assets. The second relates to the need to have customers face price signals that ensure consumption is not wasteful. At times, particularly in the context of alleged "excess" export revenues, these two key issues are characterized as being in conflict, which is incorrect.

Hydro's proposed COSS approach in the Application inadequately addresses both main issues.

With respect to stable and attractive cost-based rates objectives, Hydro's proposals to change the way export revenues are credited via the cost-of-service study (primarily in respect to customers on the distribution system) focus solely on the goal of maintaining attractive rates today for certain customer classes, with no apparent regard for the importance of maintaining stable rates for all customer groups. It is recommended that the Board weigh carefully all proposals to credit to ratepayers (via the COSS) any export revenue amounts that are concluded to be in excess of reasonable ratepayer entitlements related to their historic investment. This is particularly true for proposals that assign such "excess" export revenues to distribution assets, which have no cost-based linkage to returns from export sales. It is further recommended that the Board instead ensure that any such "excess" export revenue amounts, if and when they in fact exist, are applied to ensuring that all ratepayer classes secure stable rates over time as a separate major objective, concurrent with the attractive cost-based rates objective. Given the current level of Hydro's debt, and the recently confirmed exposure to drought risk, Hydro's proposals are not responsible compared to applying any identified "excess" export revenue towards developing regulated reserves under the direction of the PUB (not in the form of Hydro's shareholder equity) to build up protection against future droughts.

With respect to price signals relating to efficiency objectives, Hydro's proposed cost-of-service approaches ignore (and are not consistent with) the efforts in similar rate regulated hydro-based jurisdictions (such as BC) to develop cost-based rates that also send appropriate price signals for incremental consumption. Hydro's cost-of-service proposals do not satisfy, in any way, the clear and long-outstanding need to develop suitable modern rate designs. Although Hydro has portrayed its proposed cost-of-service changes as contributing to improved price signals, this is not correct and the Application makes no contribution with regard to efficient pricing objectives. Accordingly, it is recommended that the Board reject this purported basis for Hydro's proposals, and instead direct Hydro to engage in meaningful consultation with industrial and other classes of customers in the near-term, towards developing a fair approach to implement stepped rates to achieve efficient price signals.

Aside from the major changes proposed regarding allocation of export revenues, a number of other relatively small changes of varying merit are also proposed by Hydro in the Application. Proposals that energy usage be weighted to reflect the relative value of energy in different time periods are generally sound (and it is recommended that these proposals be extended to any energy component determined to be appropriate for any transmission costs). However, the specific proposals are too coarse in their definition of 4 distinct time periods; it is recommended that no less than 12 time periods should be considered. It is also recommended that, in any event, this revision to the way energy is allocated should not be combined with a wholesale move away from recognizing coincident peak as a clear driver for system investment in both generation and in all system transmission (including "export" transmission lines).

1.2 INFORMATION ON MIPUG MEMBERSHIP AND CONCERNS

MIPUG is an association of major industrial companies operating in Manitoba. The purpose of the association is to work together on issues of common concern related to electricity supply and rates in Manitoba. To that end, MIPUG intervened in each of the Board's reviews of Hydro rates since 1988, as well as the Board's review of the Centra Gas acquisition in 1999 and Hydro's Major Capital Projects in 1990.

MIPUG membership currently includes of the following companies:

- Canexus Limited (Brandon)
- INCO Manitoba Division (Thompson)
- Hudson Bay Mining & Smelting Co. Limited (Flin Flon)
- ERCO Worldwide (Hargrave)
- Enbridge Inc. (Southern Manitoba)
- Tolko Manitoba Kraft Papers (The Pas)
- Simplot Canada Ltd. (Brandon)
- Griffin Canada Ltd. (Winnipeg)
- Gerdau-Ameristeel (Selkirk)
- Tembec – Pine Falls (Pine Falls)

These companies annually purchase about 4,800 GW.h of electricity at a cost of over $100 million from Hydro (almost 25% of Hydro's domestic sales)[1]. In total, MIPUG members employ over 4,500 people, have a replacement value of their assets in Manitoba of over $2 billion, and sell over 90% of the products they produce outside of Manitoba.

In previous interventions, MIPUG members, as major power users, have consistently expressed concern about the long-term interests of Hydro's domestic customers with respect to the following items:

- The need for stability and predictability of domestic rates over the long as well as short-term.
- The need for strong regulatory oversight and approval of all rates charged by Manitoba Hydro.
- Protection for domestic customers against higher rates or risks caused by Hydro's investments in subsidiaries, new export ventures or major new capital programs that do not promote least-cost long-term rates for the utility's domestic electricity customers.

[1] 4,800 G.Wh on 19,781 GW.h for 2004/05 as reported at page 89 of Manitoba Hydro's 2004/05 Annual Report.

- Protection for domestic customers against changes in government charges for items such as water rentals, debt guarantees or any other policy-related factors that increase the general rates charged to domestic customers.
- Assurance that general customer rates are reasonable within the context of long-term cost projections and provision of secured financial reserves that are appropriate in light of Hydro's past practice and the specifics of the Manitoba market.
- Assurance that rates to each customers class reflect cost-of-service calculated in accordance with principles appropriate to Canadian regulatory practice for Crown electric utilities.

MIPUG members' concerns are reflective of the size of their capital investments in Manitoba, the long-term perspective essential to such investments and the major stake that these investments typically have in continued large-scale power purchases from Hydro. In addition, MIPUG members' concerns reflect competitive market pressures associated with selling Manitoba industrial products to external markets and the need to secure the lowest reasonable costs for power, as well as other production inputs, to offset disadvantages that arise from operations in Manitoba such as transportation and distance to markets.

2.0 THE CURRENT PROCEEDING

Hydro has filed a 2006 General Rate Application with the Board (now withdrawn) that includes proposed changes to the approach to its cost-of-service study. The Board has directed that a hearing proceed to review the proposed cost-of-service changes[2].

This is the first time Hydro's cost-of-service study approach and methods have been reviewed at a special hearing, outside of a review of Hydro's rate levels. In dealing with this precedent-setting hearing, it is important to consider items that are relevant to determining any utility's appropriate cost allocation methods. This includes general engineering and economic characteristics, as well as the framework for regulating the utility in terms of past practice, overall policy, the history under which the present system evolved, and plans for future system evolution.

This section reviews the key context for Hydro's rates relied upon in preparing this evidence. It reflects in part the history and evolution of the Manitoba system and current plans for the system, as evidenced by materials available primarily from regulatory filings and corporate reports dating from the 1980s (or in some cases before).

2.1 BACKGROUND AND CONTEXT

As a general principle, prices for electricity throughout North America are set based on one of the following three basic approaches – 1) based on markets such as in Alberta or Ontario (with government subsidies or rebates at times being provided to certain groups); 2) by government, based on political considerations, such as in Saskatchewan, and in Manitoba prior to the Crown Corporations Public Review and Accountability Act of the late 1980s[3]; or 3) based on regulated cost-of-service approaches, such as in British Columbia, Yukon, Northwest Territories, Newfoundland, Nova Scotia, Quebec and utilities regulated by the National Energy Board[4].

In Manitoba, under the current legislation, the system in place is regulated ratemaking based on costs - there is no provision for market pricing to domestic customers or for government ratemaking (outside of clear direction in legislation or regulations, such as in the case of Uniform Rates legislation).

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[2] See the letter from G. Gaudreau to P. Ramage, dated November 4, 2005 and provided as part of the response to MIPUG/MH I-8 b). The letter states in part "As indicated in Order 143/04, the Board considers the issues surrounding the Cost-of-service Study (COSS) to be significant and expects those issues to be resolved prior to considering MH's next GRA. To facilitate the resolution of the COSS issues, the Board proposes to conduct a proceeding, separate from and prior to a GRA."

[3] This approach is also similar to that used by other non-electric utilities such as many Canadian water and sewer services.

[4] In some cases, only a portion of the respective utility's rates or tolls are regulated based on cost-of-service principles.

In the context of the current proceeding, it is also important to acknowledge the fundamental tenets underlying electricity pricing and policy existing in Manitoba since at least the 1970's[5]. Manitoba electricity prices are based on the costs required to operate the public power electricity system put in place in past years. These prices reflect the underlying "heritage resources" developed and paid for by Manitoba electricity consumers[6] who took on the costs and risks related to major generation and transmission developments (both one-time investment risks, as well as ongoing risks related to water flows, plant performance, etc.). In this regard, the generation and transmission resources currently in place (the "bulk power" system) represent the entitlements of ratepayers to *attractive* and *stable* electricity prices. Export revenues have been integral to this policy approach, in that the ability to export power enables development (and in some cases allows advancement of development) of large northern hydro stations, in excess of what would be required for solely domestic requirements at any given point in time.[7] This allows rates to be lower than they would otherwise be (were the major hydro developments not otherwise possible) and more stable (since fluctuations and risks related to Manitoba load levels can be offset in part by complementary changes to quantity of power exported, and since the ongoing costs of hydraulic generation are not subject to fuel price fluctuations).

In the case of similar hydro-based electric power jurisdictions, such as Quebec and BC, the scale and scope of heritage resources has been defined and confirmed by government policy as a stable and protected assurance of a secured quantity of low cost generation[8] (stable in that the quantity and pricing mechanism are fixed and not subject to risks of drought, etc.). In Manitoba, the objective of attractive and cost-based rates is achieved via setting a cost-based revenue requirement (net of export revenues) for the utility in total, as well as for each customer class. Manitoba, however, does not have well

[5] This basic set of principles is set out in numerous documents from the 1970's through the present, including reports of Manitoba Hydro, the provincial government, the PUB, as well as previous agencies such as the Manitoba Energy Authority.

[6] In the case of the HVDC system, there was financing from the Government of Canada, provided for the benefit of Manitoba electricity consumers.

[7] This basic relationship is set out in detail in the PUB's Report to the Minister regarding Manitoba Hydro's 1990 Capital Plan, section 3 and page 5-4.

[8] In Quebec this is represented by an assured supply to domestic customers of 165 TW.h at a price of 2.79 cents/kW.h from the heritage pool of electricity as set out in section 52.2 of An Act Respecting the Regie de l'énergie. In BC this is represented by a "Heritage Energy" amount of 49,000 GW.h which is to be provided to BC Hydro Distribution based on the embedded costs of the Heritage Resources as described at page 16 of the BCUC Report and Recommendations in the Matter of British Columbia Hydro and Power Authority and An Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access (October 17, 2003).

developed means to assure the stability of rates in the face of the risks of drought[9] (as reviewed in detail at the 2004 GRA).

Similarly, these same basic tenets have been confirmed in the current Manitoba plans to develop or enable new renewable supply resources, such as new hydro and wind, based on the ability to make high value sales to export markets. In each case, the premise put forward by Hydro (such as at the recent Wuskwatim CEC hearings) is that these generation investments are aimed at maintaining stable and low cost electricity for Manitobans, along with all the associated advantages for cost-of-living, jobs and investments, and development of renewable public resources (and in the current hydro developments, opportunities for northern community investment). Unlike major new generation brought on-line in places such as Ontario in past decades, which resulted in major rate increases, current Manitoba plans are to develop new generation for export markets such that there are beneficial impacts on Manitoba ratepayers.

Contrary to possible misconceptions, the Manitoba framework does not require prices for power within the province to be set at a level that encourages inefficient use. As reviewed later in this evidence, rate designs to ensure all existing customers face consumption decisions that discourage wasteful use and encourage conservation and self-generation are not in any way inconsistent with the overall Manitoba "power at cost" approach (even though this type of "efficient price signal" rate structure does not exist in Manitoba today[10]). Sending efficient price signals via rate design can be done in a way consistent with the fundamental Manitoba tenets set out above, so long as the price signals encourage efficient use and discourage inefficient use, but at the same time do not penalize or create barriers against growth (be it new residences, new industries, or expansions of existing industries). Under market approaches, or quasi-market approaches such as full marginal cost-of-service, the latter effect arises.

[9] Manitoba's sole approach to maintaining some stability in regards to drought risk is to earn significant net income in high flow years, which is accounted for as "shareholder's equity" so that significant net losses in drought years can be borne. This is in significant contrast to a number of other utilities who often maintain various regulatory "stabilization" accounts under the direction of the respective regulator, with specific detailed rules regarding use of the funds (in some cases accounted for analogous to a trust account by the utility). This is further set out in cross examination of Mr. Osler and Mr. Bowman by PUB counsel at 2477-2483 of the electronic transcript from Hydro's 2004 GRA.

[10] However, there is a subtle but fundamental difference between designing rate structures that ensure efficient consumption decisions for existing customers but retain an overall "power at historic cost" framework, and the more "marginal cost" based approaches that mimic the significant adverse total income effect of markets (for either all consumption or all "new" consumption). As a simple example, a residential customer who increases their consumption should face prices for the increase that reflect underlying cost changes on the system related to that increase – requiring higher rates for that increased consumption than the overall average rate (an "inverted" rate design approach). However, this is fundamentally different than charging all new residential customers that higher rate for all of their consumption on the basis that they are effectively all "new load". The same considerations apply for industrials.

Nothing has been provided by Hydro or the government to indicate a change to this fundamental policy of power at cost, based on historic investment with export revenue offsets, to sustain attractive and stable cost-based rates.

2.2 BACKGROUND TO THE CURRENT PROCEEDING

During Manitoba Hydro's 2002 Status Update proceeding, the Board and intervenors reviewed proposed changes to Hydro's cost-of-service study methodology. Order 7/03 arising from that proceeding summarized the Board's conclusions, and in most instances rejected the changes proposed by Hydro. The Board also ordered that Hydro file a study that reviews generation classification methodology options.[11]

As part of the 2004 proceeding, Hydro submitted a Prospective Cost-of-Service Study (PCOSS) based on the approved methodology arising from the 2002 Status Update proceeding, as well as a study prepared by NERA Consultants[12] that responded to the Board's 2002 directive to review generation classification methods and critically examine the impacts of the various methods of classifying generation costs. The NERA report reviewed several generation and transmission classification and allocation methods and recommended certain changes to Hydro's cost-of-service methodology. Hydro did not implement the recommendations of the NERA study in the PCOSS filed with the 2004 GRA[13] but stated:

> The NERA report was filed to comply with directives in Order 7/03 and 154/03, and was not intended to be reflected in the current GRA. Manitoba Hydro may incorporate some or all of the recommendations in future cost-of-service studies.[14]

In its decision with respect to the 2004 GRA, the Board noted its concern that "Because the COSS methodology is in a current state of flux, and in the Board's view incomplete, the Board can no longer rely on the current methodology in assessing the revenue to cost coverage rates for each customer class."[15] The Board directed Manitoba Hydro to file three separate COSS models to reflect the existing methodology, the implementation of the NERA recommendations and MH's preferred approach and methodology, as well as the impacts of allocating less expensive generation to domestic classes and more expensive generation to exports (generation vintaging, effectively a fourth COSS model).[16]

[11] Page 111, Order 7/03.
[12] Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies dated February 11, 2004.
[13] This was confirmed in response to MIPUG/MH II-15 b) from the 2004 GRA.
[14] See the response to PUB/MH II-3 b) from the 2004 GRA.
[15] Page 97, Order 143/04.
[16] Directive 4 and 5, Order 101/04.

2.3 ROLE OF COST-OF-SERVICE IN ELECTRICITY PRICING

Cost-of-service studies are used by regulated utilities to assess and to justify to their customers and regulators that the costs to be recovered from rates charged to different customer classes and for different services are reasonable. The National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual notes that cost-of-service studies are commonly used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets [in cases where the utilities have unregulated operations].[17]

Manitoba Hydro has been submitting cost-of-service studies for Board review since at least 1986.[18] In its March 31, 1988 report to the Minister, the Board stated:

> Cost-of-service studies are used to determine the fair sharing, between customer classes, of responsibility for the Utility's total revenue requirement. While there are many allocation methods, the central aim is always to allocate costs to customer classes on the basis of known customer characteristics.[19]

In every rate proceeding since then, Manitoba Hydro has provided the Board with a PCOSS to calculate the relative level of rates required from each customer class. These PCOSS have typically been done on a forecast or prospective basis using Hydro's forecasts for its costs under median water conditions, and its domestic system loads. In simple terms, the annual PCOSS take Hydro's forecast costs and ultimately allocate them to the various domestic customer classes, based on data from the domestic load forecasts, to derive a total cost of serving each class. This approach, however, assigns all the costs of Manitoba Hydro's generation and transmission system to domestic customers, even though on the order of 40% of

[17] Taken from page 12, NARUC Electric Utility Cost Allocation Manual. 1992.
[18] The 1986 COSS was the subject of the Public Utilities Board report to the Minister dated March 31, 1988.
[19] Page 53, Manitoba Public Utilities Board report to the Minister, March 31, 1988.

the system services export loads[20].

The current PCOSS approach is designed to ensure that the export revenues arising from the approximately 40% of generating system output are credited back to bulk power rates in equal proportion to the costs each customer class is paying for the bulk power system from which the exports derive. Absent this (or some similar) approach to crediting export revenues, domestic customers will be paying for the bulk power assets used by export sales, but will not receive an offsetting benefit that bears any relation to the costs they pay towards these assets.

In each of the previous rate review proceedings, the Board has reviewed the merits of the cost-of-service methodologies employed by Manitoba Hydro and directed the Corporation, where necessary, to make adjustments to more properly reflect the principles of cost causation on Hydro's system. In all cases since at least the construction of Limestone, the Orders reflected refinements to the methodology to more accurately track the costs of Hydro's system, as opposed to major revisions to reflect changes to Hydro's system itself. The results of Hydro's COSS studies since 1992 are reviewed in more detail in Attachment B.

[20] The 2005 Manitoba Hydro annual report indicates sales volumes for the period 1996-2005 (as well as for 1993-1995 in the 2001 annual report) showing export sales at generally range of 9-12 TW.h annually since Limestone came into full production (with 2004 below this level at 4.4 TW.h and 3 years above this range at a maximum of 13.6 TW.h) on total energy delivered of 25-29 TW.h (with 2004 below this level at 23.7 TW.h and 3 years above this range to a maximum of 29.5 TW.h).

3.0 KEY ISSUES RAISED IN THE CURRENT PROCEEDING

The materials filed by Hydro in the current cost-of-service proceeding focus almost entirely on two key issues: allocation approaches for export revenues that are considered to be beyond the appropriate limits of established cost-based approaches approved to date[21], and sending proper price signals to customers[22]. Ironically, neither of the major issues upon which Hydro focuses is properly a cost-of-service topic.

- **Excess Export Revenue:** Hydro contends that export revenues have crossed some threshold and should no longer be allocated to customers based on cost causation. This issue is in fact a revenue requirement topic. Excess export revenues that are alleged to no longer bear any proper linkage to cost causation are merely a subsidy to rates and cannot be dealt with in any principled way under any COSS approach. As such, they should be addressed in the context of a utility's revenue requirement calculation.
- **Price Signals:** Improving price signals to existing customers is essentially a rate design topic. Any cost-of-service approach can support either good or bad price signals, depending on the rate design[23].

Nevertheless, in the Application, Hydro has attempted to develop a cost-of-service solution to each of these two issues. For this reason, the COSS solutions proposed by Hydro are complicated, contentious, and lack any basis in established cost-of-service methodology in Manitoba or elsewhere.

The balance of this section of the evidence provides some perspectives on these two key issues. Analysis and discussion of Hydro's other proposed cost-of-service study changes are provided in Section 4.

3.1 EXCESS EXPORT REVENUE

In PCOSS06, Manitoba Hydro identifies export revenue allocation as the key issue[24] underlying proposed revisions to Manitoba's cost-of-service methods today. Manitoba Hydro provides a number of reasons throughout its filing as to why it considers the treatment of export revenue to be problematic, generally summarised as follows:

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[21] See for example page 3 of PCOSS06 where Hydro suggests that changes in the nature of export revenues means the longstanding method of crediting export revenues to the customer classes is no longer appropriate.
[22] See for example the discussion on page 24 of PCOSS06.
[23] This was confirmed in Hydro's response to MIPUG/MH I-15 d).
[24] Also see presentation by Mr. Warden at November 24, 2005 Pre-Hearing Conference, transcript page 21 lines 20-24.

a. Export revenue has grown substantially in dollar value (although not in volume[25]) since the current COSS approach was reviewed and was repeatedly confirmed as reasonable and proper in the mid 1990s[26] (and again in 2002[27]). The growth in value is in part indicated to be a result of increased reliance on firm export sales and relatively less reliance on opportunity sales[28]. (However, it should be noted that growth in export prices (as well as changes to the configuration of the Manitoba Hydro system to maximize the ability to make firm export prices) has also resulted in increased overall risks for ratepayers from financial impacts of droughts[29].)

b. Domestic rates are currently lower than rates in adjacent jurisdictions to which Manitoba Hydro exports electricity.[30] (It should be noted, however, that Manitoba Hydro's rates since at least the mid 1980s have been basically the lowest in Canada, and below the levels in Minnesota or other interconnected jurisdictions for basically all rate classes; this factor alone does not provide any meaningful indication that the treatment of export revenue is problematic.)

c. As export prices and consequently revenues increase, the current Cost-of-Service (COS) approach results in excess export revenues being credited against bulk power costs in the PCOSS, driving the overall level of domestic rates to each customer class lower, which is an inverse price relationship to the markets. (This inverse relationship is nothing new in Hydro rate setting in Manitoba – the new factor is the alleged "excess" export revenues and the extent to which opportunity as well as firm export sales have recently secured prices in excess of domestic rates.)

d. The lower domestic electricity prices compared to the market prices[31] in adjacent jurisdictions to which Hydro could export power may cause domestic electricity customers to be wasteful. (It can be noted, however, that Hydro is inconsistent with its definition of "wasteful" use. In some cases any growth, even from entirely new loads such as new industrial customers or new

[25] Volumes of export sales forecast in PCOSS 06 are in fact lower than at almost any period since Limestone came into full service in the early 1990's. The major difference in the export sales revenues is from increases in price.

[26] Including the 1993/94 GRA and the 1996/97 GRA, in light of arguments at that time to change the export allocation practice from at a minimum CAC/MSOS and the Government of Canada.

[27] In contrast to Hydro's proposals at that time to allocate a portion of export revenues to distribution which was rejected by the Board.

[28] See for example page 3 of PCOSS06.

[29] Hydro now estimates the impact of a severe drought at potentially $2 billion. Testimony of Mr. Osler and Mr. Bowman from the 2004 Hydro GRA indicate concern over the scale of this risk and the degree to which it has been in part enhanced by changes to the configuration of Hydro's system, such as the conversion of Selkirk to natural gas, the construction of increased transmission to the United States, and the construction of the Brandon combustion turbine, all of which increase the ability to access export markets on a firm basis, but enhance the cost risks related to drought.

[30] For example, industrial rates in other interconnected jurisdictions are shown in PUB-MH-II-35.

[31] Manitoba Hydro notes at page three of PCOSS06 that average export prices can exceed, sometimes by a significant margin, average domestic rates.

houses is effectively cited to be a problem, even though there is no argument that such use is inefficient[32].)

Hydro's position appears to be that the current cost-of-service approach to allocating export revenues as a credit against rates charged is a "distortion" since there is simply too much export revenue today to retain this older approach for all export revenue. In short, the position appears to be that the system has been too successful in providing attractive cost-based rates.

Hydro's focus, however, completely ignores the extent to which the system is or is not today successful in maintaining and enhancing the stability of rates. In contrast to the attractive cost-based rates objective, the 2004 GRA reviewed in detail how the current system is increasingly becoming poorly suited to ensuring stability of rates in the face of potential major droughts (which are now estimated to drive costs of upwards of $2 billion).

The record is clear that for some magnitude of export revenue, the cost-of-service treatment historically used in Manitoba reflects a fair and appropriate means of providing ratepayers with the returns to which they are entitled, based on the proportion to which they today bear the costs of the historic investment in bulk power assets. This is in part borne out by the fact that on numerous occasions Manitoba Hydro argued in favour of this treatment of export revenues[33] and against allocating export revenues to the distribution function[34].

It is also clear that Hydro considers export revenues to have crossed some "threshold", where the standard approaches to providing this benefit directly via bulk power rates are no longer appropriate. However, Hydro does not explicitly attempt to define the threshold beyond which export revenue exceeds the fair ratepayer entitlement to a return on the bulk power investment via their rates (as opposed to through any other mechanism, if at all).

Although Hydro has not defined the fundamental scope and scale of the problem it is purportedly trying to address, in the Application it proposes a major and complicated change to the way export revenues are treated for cost-of-service purposes. Notably, these proposals are not based on any normal regulatory precedent or principle[35] and Hydro has provided no link as to how this approach reflects the historic

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[32] See for example MIPUG-MH-I-15(a)

[33] See for example page 3 of the response to RCM/TREE/MH I-11 a) which summarises Hydro's position on the treatment of export revenues in the 1994 GRA as recorded in PUB Order 62/94.

[34] Manitoba Hydro confirms in the response to MIPUG/MH I-13 b) that it did on several occasions during regulatory proceedings argue against allocating export revenues to distribution functions.

[35] In response to MIPUG/MH I-12 d) Manitoba Hydro stated that it was not aware of any decisions of any regulatory tribunal that direct allocation of export revenues to distribution functions.

investments made by the utility. The proposals also completely fail to reconcile why, if Hydro alleges these revenue amounts are in excess of what can be reasonably credited against bulk power assets, they propose to credit them back in any form of lower rates?

Based on established Manitoba practice, it is entirely appropriate as a starting point to allocate net export revenues to the generation and transmission functions that give rise to those revenues. Nothing has changed in the factors underlying the conclusion that it is reasonable and principled to allocate at least some portion of export revenues in that manner. To the extent that there is a threshold above which that treatment becomes problematic, it appears that some effort should be invested in identifying and defining that threshold, as well as in assessing the appropriate method(s) for providing returns to ratepayers from the export revenues in excess of the threshold.

An Export Revenue Threshold

As noted, Hydro's filed material implicitly assumes the existence of an export revenue threshold beyond which existing cost-of-service methods are no longer appropriate, but makes no explicit attempt to define that threshold. Similarly, the approaches proposed by NERA attempt to address this relationship in their cost-of-service proposals without providing any explicit means of defining the threshold.

Hydro and NERA each propose to directly assign certain costs against export sales, either as a new class of customer, or directly to the export sales based on variable costs incurred to make the sales. The remainder of the "net export revenues" is credited back against remaining costs focused on both Generation and Transmission (as per established practice) as well as Distribution, Subtransmission, Customer Service, and Diesel (approaches roundly rejected by Hydro and the PUB in the 1990's). Ultimately, NERA proposes allocating approximately $74 million against the non-bulk power component, and Hydro proposes allocating $97 million[36]. In effect, it is these amounts that may be summarized as Hydro's and NERA's estimation of the degree to which current export revenues exceed the threshold of reasonable application of past practice (as all other amounts, outside of $17 million in Uniform Rates subsidy, are effectively credited to the bulk power system as per past practice).

The level of export revenues has clearly grown since the 1993/94 and 1996/97 GRAs, as noted in Table 3-1 below.

[36] In each case these amounts are in addition to $17 million in export revenues allocated directly to these same customers for the impact of the Uniform Rates legislation. $74 million is derived as the sum of export credits allocated to Sub-Transmission ($12.4 million, Distribution ($49.1 million), Customer ($12.8 million) and Diesel Distribution ($0.1 million). $97 million for the Recommended method is derived as the sum of export credits allocated to Sub-Transmission ($16.2 million), Distribution ($63.8 million), Customer ($16.7 million) and Diesel Distribution ($0.2 million).

Table 3-1
Comparison of Export Revenues in Manitoba Hydro's Cost-of-Service Studies

$millions	1993/94 GRA (PCOSS95)	1996/97 GRA (PCOSS97)	2002 Status Update (PCOSS02)	2004 GRA (PCOSS04)	Current (PCOSS06 – current method)
Gross Export Revenues	$250.8	$264.0	$491.0	$519.9	$547.4
Less: directly variable costs incurred to serve exports	($19.3)	($21.0)	($76.6)	($100.6)	($107.1)
Less: Uniform Rates allocation	n/a	n/a	n/a	n/a	($16.7)
Net exports per PCOSS	**$231.5**	**$243.0**	**$414.4**	**$419.4**	**$423.6**
Total Bulk Power costs	**$727.9**	**$763.7**	**$1058.9**	**$999.3**	**$1099.4**
Less: portion directly incurred to serve export (per above)	($19.3)	($21.0)	($76.6)	($100.6)	($107.1)
Total PCOSS bulk power costs before export credit	**$708.6**	**$742.7**	**$981.6**	**$898.7**	**$992.3**
percentage of PCOSS bulk power costs covered by net exports	*32.7%*	*32.7%*	*42.2%*	*46.7%*	*42.7%*

It is evident that the dollar values of forecast gross export revenues for the PCOSS have approximately doubled since the mid 1990s. Over the same period, costs directly assigned against these exports (both directly variable costs that would not have been incurred absent exports, and direct allocation of the Uniform Rates costs) have increased well over 5 times. It is also apparent that Hydro's overall costs to operate the generation and transmission system have increased substantially in this same period (nearly

50%, and in particular by about $100 million in the last two years, to levels which have not been tested by the PUB in a rate proceeding to date). Consequently, the growth in net exports allocated against the bulk power system, using a consistent methodology, is from about 32.7% in 1993/94 and again in 1996/97 to about 42.7% in PCOSS06.

Considering the approaches used by Hydro and NERA to derive their effective "excess" export revenue values through their respective mathematical models, there should be some basis for providing a reasonable and simple cross-check on these approaches. For example, it is apparent that the treatment of export revenues in the 1996/97 GRA was patently reasonable and confirmed by Hydro and the PUB given the revenue levels at that time in proportion to overall generation and transmission costs (about 32.7% of total generation and transmission costs); it is also apparent that the Hydro position today is that the same treatment in 2006 is conversely unreasonable (when net exports total 42.7% of overall bulk power costs); accordingly, if the "threshold" was assumed to be at the simple mid-point of these two cases (at 37.7%), about $374.1 million of net export revenues would be reasonably considered to be fairly treated using the standard methodology previously approved by the PUB. Under this assumed mid-point approach, approximately $49.5 million of the forecast PCOSS06 export revenues are then above the threshold[37]. This is fully 12% of the net export revenues, but still well below Hydro's implicit calculation and proposed allocation to the distribution system noted above.

Adopting a threshold approach in this manner allows retention of the standard, principled and repeatedly confirmed approach to treatment of export revenues in the PCOSS for exports below the identified threshold, while exports above the threshold would not be included in the PCOSS. This approach is both simpler and more consistent with cost-of-service precedent in Manitoba and elsewhere than the approach now proposed by Hydro. However, this type of approach is not without issue – there is clearly a need, for example, to determine on a principled and practical basis where such a threshold may be both for today and for future PCOSS studies, including after the potential in-service of future major new generation plant such as Wuskwatim, Keeyask and Conawapa which are being proposed (in part) as a means to sustain export revenues and thereby to retain low cost-based rates for Manitoba ratepayers. To the extent that any consideration is to be given to the "excess" export revenue concerns raised in the Application, a meaningful consideration of approaches to determining the level of such a threshold for today and the foreseeable future is clearly required.

[37] $374.1 million is derived by multiplying 37.7% by the $992.3 million in bulk power costs in PCOSS06. $49.5 million is the residual of $423.6 million less $374.1 million.

Treatment of Export Revenues Beyond a Threshold

In the event that the Board concludes that some portion of today's export revenues are beyond any reasonable allocation in the PCOSS based on established practice, and some specific "threshold" is also determined on a principled basis, it becomes necessary to determine the appropriate treatment of this "excess" export revenue. In this regard, a number of approaches might reasonably be considered; however, there is no principled basis to use any of this revenue to lower rates to any group of customers, regardless of the class or economic characteristics of the customer. The following points are noted in this regard:

a. **As a preferred approach, apply a portion of export revenue to pay down debt via a "regulated reserve fund" against future droughts.** The most attractive alternative for use of export revenues that are in excess of amounts that can be reasonably addressed by principled COSS approaches likely is to allocate these amounts towards a regulated reserve fund for future use to stabilize rates in the event of a drought. This approach would simultaneously allow for repayment of portions of Hydro's debt (which is currently at unprecedented levels, and scheduled to grow, particularly with new northern generation and transmission proposed[38]), and development of reserves to address future drought risks. Depending on the approach noted in the section above, it is conceivable that amounts in the range of $50 million (to perhaps as high as $100 million) in 2006 might suitably be considered for this purpose. Key to this approach is development of a mechanism to ensure that the amounts are held in a regulated reserve under the direction of the PUB, rather than as Hydro's shareholder equity which is subject to all sorts of potential constraints or pressures. This treatment may be appealing particularly in light of the Board's continued concern with respect to Hydro's overall level of debt[39], lack of suitable reserves to address drought risk[40] and the fact that such a treatment would have benefits for all ratepayers by reducing Manitoba Hydro's interest expense requirements in future years.

b. **No basis today to define any "surplus" towards increased payments to the shareholder**: Other Canadian jurisdictions provide mandatory mechanisms whereby Crown utilities who have reached a reasonable level of capitalization and with sufficient reserves can

[38] Refer to IFF MH05-1 page 33 which shows the sum of forecast long-term debt plus current and other liabilities to be $8.760 billion in 2005/06 growing to $9.798 billion by 2009/10 and $11.598 billion by 2015/16.

[39] The Board most recently expressed this concern in Order 34/05 with respect to Manitoba Hydro's conditional rate increase where the Board stated at page 17 "Hydro's financial results and position have implications for the overall position of the Province, being Manitoba's largest Crown Corporation and having a debt level that represents more than 50% of the Province's outstanding debt."

[40] In Order 143/04 at page 85, the Board stated "This drought also highlighted the increased risks faced by MH in the export market, and the resulting need for MH to build and maintain adequate reserves in advance of further significant investments in generating and transmission facilities."

or must declare a dividend or "distributable surplus" that is paid to the respective province. A summary of relevant dividend policies for Crown utilities in Canada is outlined in Attachment A. However, there is currently no legislated provision for Manitoba Hydro to declare a dividend beyond amounts already paid out in 2003/04 and 2004/05[41]. More importantly, however, Manitoba Hydro's current debt:equity ratio exceeds the level at which provincial legislation in many jurisdictions would prohibit a dividend[42] and Hydro maintains no special reserves to deal with Rate Stabilization or drought as suggested by the PUB[43] (as well as Mr. Osler and Mr. Bowman in the 2004 GRA[44]). In this regard, even if not needed to maintain attractive cost-based rates today, the export revenues collected today are not "surplus" as this term is used on other provinces.

c. **No basis for direct one-time rebates to customers or other forms of payouts:** Occasionally in previous Hydro rate hearings, the concept of one-time rebates or payouts of export revenue directly to customers has occasionally been raised[45]. In the case of Manitoba Public Insurance, one-time excesses in the level of reserves are on occasion distributed by a simple direct rebate to customers[46]. However, such an approach is not suitable for ongoing amounts such as Hydro's export revenues (compared to one-time amounts), and seems likely in the case of Hydro to be contentious, difficult to administer and of questionable merit. Given the clear advantages of investment in rate stabilization measures that simultaneously reduce Hydro's debt and build up a reserve for future droughts, there would not appear to be any reasonable basis at this time to distribute any form of payouts to customers.

In summary, even if a PUB determination is made that export revenue is now beyond some threshold where allocation of these amounts as an offset to bulk power costs is "distorting", this provides no principled basis for the Hydro proposals in the Application. In the event it is determined that any export revenues should no longer contribute to maintaining the level of bulk power cost-based rates, these excess export revenues should now properly be targeted (in the context of Hydro's revenue requirement determinations) to reducing risks arising from the Hydro system related to droughts.

[41] These were amounts the Province required Manitoba Hydro to issue as a 'special export payment' through legislation.

[42] See Attachment A for more discussion on this topic.

[43] Page 37, Order 101/04.

[44] For example, in the MIPUG evidence from that hearing at page 23-24.

[45] This includes evidence submitted by TREE in the 2004 GRA, page 12 and cross examination of Mr. Osler and Mr. Bowman by PUB counsel at page 2670-2671 of the electronic transcript from the 2002 Status Update proceeding

[46] Transcript from the 2002 Status Update proceeding, electronic version page 2670-2671.

3.2 PRICE SIGNALS

Hydro's filings cite in a number of places that the price signals being sent to customers are poor, since its rates are low compared to market prices and thereby discourage conservation. Hydro indicates that this is partly a consequence of the issues noted above regarding export revenues, and partly due to domestic rates being lower than "marginal cost" (defined by Hydro as the price it could secure on export markets for this power).

The simple assertion is that if rates in Manitoba were equal to full marginal costs, there would be no price signal efficiency issue. This proposed solution to the efficiency concerns, however, raises two related issues:

a. **Excess revenues from full marginal cost pricing:** Setting rates equal to the full marginal costs, as defined in the NERA Time of Use study, would necessitate an approximate 22% increase to residential customers, 57% increase to General Service – Demand customers, and 71% increase to large industrials[47]. This rate setting approach would be further exacerbated in the event that certain future actions (such as improved transmission access to export markets) provide enhanced export revenues. In general, this approach means improved exports access would raise domestic rates (contrary to the currently stated intention of export-related developments)[48]. This type of approach clearly challenges the fundamental aspects of current and historic Manitoba electricity policy, where Manitoba ratepayers have taken on risks and costs related to investing in new hydro (as well as plans to support investment in hydro and other renewable generation in future) in exchange for benefits derived from the associated export revenues that help maintain Manitoba rates at a level lower than external markets. Were such a "marginal cost" policy desired, it could likely be more readily achieved by simply setting up domestic markets for power (as in Alberta or Ontario) with all the associated "efficiencies" and related issues (such as government-funded rebates to customers required to offset consequent major price increases).

b. **Methods to receive efficient price signals while retaining cost-based rates:** To secure efficient pricing for any given customer of any type (from residential to large industrial) in the

[47] Page 20, Time-of-Use and Inverted Electric Rate Structures for Application in Manitoba. NERA. 2005. Also note that such an approach would cause Hydro to earn $404 million in excess of its revenue requirement. NERA notes that this excess revenue over revenue requirement can be credited back to customers, but this would clearly undermine the alleged efficiency gained by setting all rates equal to marginal costs, since these rates would now be "subsidized" below marginal cost levels.

[48] For example, were Manitoba Hydro to build a new international transmission line to allow it to capture more of the high on-peak prices compared to its present transmission line constraints, this would raise the marginal costs measured in this way and lead to higher domestic rates, even though Manitoba Hydro has repeatedly confirmed that major new generation and transmission to allow for new exports is designed in part to aid in maintaining lower Manitoba rates.

context of regulated cost-based rates, it is only necessary to design their rates so as to ensure that the ***marginal*** consumption (and not all consumption) is priced at marginal cost. This is the basis for stepped rate designs for many types of customers in other jurisdictions, including for example, industrials in BC and Yukon, and as set out in the NERA Time of Use study. This type of rate design can be implemented with Manitoba Hydro's existing cost-of-service approach without requiring the complicated changes proposed by Manitoba Hydro and NERA[49].

Many parties, including in the evidence called by MIPUG (prepared by Mr. Osler and Mr. Bowman) in the 2004 Hydro hearing[50], have argued that Manitoba Hydro's price signals can be considered poor and consequently customers and the utility are being adversely impacted. If marginal consumption for industrials was priced at marginal costs (potentially similar to the BC Hydro rate example cited in the 2004 MIPUG evidence) customers would see larger benefits from participation in Demand Side Management (DSM) and conservation activities, would experience economic encouragement to develop Independent Power Producer (IPP) and co-generation from such products as wood waste (compared to Hydro's current IPP policy which effectively discourages such biomass generation), and would retain overall electricity pricing that retains their current level of competitiveness. Hydro has confirmed in MIPUG-MH-I-15 (d) that this is possible under any cost-of-service approach, including the current approach.

[49] MIPUG/MH I-15 d).

[50] See pages 10 and 11 of the 2004 Pre-Filed Testimony of J. Osler and P. Bowman.

4.0 CLASSIFICATION AND ALLOCATION OF BULK POWER RESOURCES

Hydro's proposed changes to the cost-of-service methodology are related entirely to the bulk power system, both generation and transmission. Aside from adjustments related to export revenues as discussed in section 3, the proposed COS changes comprise two general themes:

1) With respect to classification of costs, Hydro's proposals reflect an increased emphasis on energy rather than capacity. This applies to export transmission lines and generation assets, which previously had been classified either entirely as capacity-related[51], or to capacity and energy on the basis of system load factor.
2) A new "weighted" energy allocation that effectively assigns greater weight to energy used at peak times than at non-peak. This applies to basically all generation assets[52].

4.1 CLASSIFICATION OF COSTS TO DEMAND VERSUS ENERGY

Hydro proposes to change the classification of export transmission lines to 100% energy (from basically 100% capacity, allocated based on coincident peaks), and to increase the energy-weighting of generation costs to 100%[53] (these had previously been classified based on system load factor, but then adjusted in a complicated re-balancing with transmission so as to bring generation classification up to approximately 82% energy and 18% demand in PCOSS06 under the current method[54]).

There is no basis today to indicate that capacity (coincident peak) is no longer a reasonable cost driver or allocation method for the Hydro system:

- For ***export transmission lines***, the proposed 100% energy treatment is at odds with all cited precedents from other jurisdictions reviewed by NERA, in which nearly all of the surveyed

[51] Export transmission lines were previously not defined in the PCOSS apart from other transmission, but all Hydro transmission was effectively classified as 100% demand and allocated on 2 CP; note however that all transmission amounts classified as demand reduced the percentage of generation assets classified as demand.

[52] In response to MIPUG/MH I-3 a) Hydro notes that there is a small demand component in Generation for the DSM curtailable credit which is an energy neutral program and thus allocated on demand (2CP).

[53] Hydro notes in the response to MIPUG/MH I-3 a) that a small demand component in Generation for the DSM curtailable credit that is allocated on demand (2CP).

[54] See Pages 80 and 81 of Appendix 11.3.

- utilities reported classifying all transmission as 100% demand related[55]. To the extent that Hydro indicates a preference for energy weightings to reflect the market-related nature of these lines, at a minimum this should only account for a portion of the costs and the allocator should be the marginal "weighted" energy to reflect the relative value of peak periods versus non-peak. However, even this represents a major departure from the nearly universal treatment of transmission as being 100% demand-related in cost-of-service (even for export loads, such as under the FERC transmission tariff[56]) and also fails to reflect the role these lines can play in importing power at critical peak times – an inherently coincident peak cost driver.

- For ***generation***, the classification to 100% energy fails to reflect practice in any other regulated jurisdictions surveyed by NERA[57] and also fails to reflect that Manitoba Hydro considers both energy and peak capacity criteria when evaluating the need for new generation or evaluating different generation resource options.[58] It therefore seems reasonable and necessary for a generation classification method to reflect both energy and coincident peak capacity considerations. In this proceeding Hydro states that it believes its proposed approach to developing a marginal cost weighted energy allocator adequately captures a "capacity premium"[59], but as noted below there is clearly a difference between the relative importance of the entire summer on-peak as a high-priced time-of-year, and the critical single hour (or 50 hour) coincident peaks. This value of peak capacity is reflected in part in the values attributed to the Curtailable Service Program or in demand-related DSM programming, and it is only reasonable to maintain a similar coincident peak demand related classification for at least part of the generation system. Based on past practice and precedents from other jurisdictions[60] this

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[55] Refer to the tables on pages 21-23 of the NERA report titled Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies, 2004. That report cites BC Hydro, Bonneville Power Authority, Hydro Quebec, Idaho Power, Newfoundland and Labrador Hydro, Northern States Power Co., Ontario Hydro and Salt River Project all as treating transmission costs as 100% demand related. Tennessee Valley Authority is noted to classify all generation and transmission costs 100% to demand except for fuel, purchased power, corrective maintenance and a portion of research and development. Pacificorp is noted to have an arbitrary split for fixed generation and transmission costs at 75% demand:25% energy with variable costs all demand-related except fuel and purchased power.

[56] See Section J, page 128 of the Status Update filing where Hydro notes that the then proposed transmission classification to 100% demand was consistent with treatment of transmission in the FERC Transmission Tariff.

[57] NERA's survey on pages 21 to 22 of the Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies reviews the generation classification methods for 10 utilities in addition to Manitoba Hydro. Nearly all of the utilities reported in the table indicate some method for classifying generation between energy and demand. Only Bonneville Power Administration is cited as using marginal costing methods to approximate marginal demand cost.

[58] MIPUG/MH II – 4 a).

[59] See, for example, the response to CAC/MSOS/MH I-11 e).

[60] Several of the utilities surveyed by NERA, including Salt River Project, Newfoundland and Labrador Hydro, Hydro Quebec and Idaho Power are cited as using the load factor method.

ratio can reasonably be set using the system load factor (65.60%)[61], or approximately 34.40% to demand in PCOSS06.

Further, as Hydro has now determined that export transmission lines should be functionalized separate from domestic transmission, there does not appear to be any remaining rationale for the 2 CP allocation for domestic transmission. This approach was adopted in the 2002 proceeding, and had previously been a 1 CP allocator (allocation based solely on the winter peak, rather than a blend of the winter and summer peaks). Allocation using 1 CP is consistent with a system that has a distinct winter peak well above the levels that are set in the remainder of the year. Hydro's system outside of exports has this type of load profile. As Hydro's key transmission for export purposes is currently not included in the "domestic transmission" category (either functionalized as "generation" for the HVDC system, or as "export transmission" for the cross-border lines), there is no remaining rationale for a 2 CP allocator for the domestic transmission category. This function should now return to a 1 CP allocator.

4.2 ALLOCATION OF ENERGY COSTS BASED ON "WEIGHTED" ENERGY CONSUMPTION

In regards to new proposals to use marginal cost weighted energy for allocating generation costs, there appears to be merit as long as issues related to confidentiality of data can be addressed[62]. This is due to the fact that energy on Hydro's system is clearly of varying value depending on the time consumed, with peak period consumption (lower load factor customers) ultimately driving far more costs than more balanced consumption (higher load factor customers).

Hydro has proposed the use of average (inflation adjusted) historic Surplus Energy Program (SEP) rates, which seems to be a sound practical approach to deal with the confidentiality issue. Manitoba Hydro states that, in its opinion the SEP data is a better proxy for Manitoba Hydro's marginal cost than the use of other market data (such as Platt's), since the SEP data incorporates not only the prices from the interconnected market but also accounts for Manitoba Hydro's use of its own thermal generation (at times for local load support) and Hydro's often limited ability to access export markets due to transmission constraints.[63]

The marginal cost weightings Hydro proposes to use are summarized in Table 4-1[64].

[61] See MIPUG/MH I-4 a).

[62] The 2002 Status Update COS proposals by Hydro sought to use marginal cost data that was from confidential sources, so the PUB and Intervenors were not suitably able to test the data. This was a sufficient concern that Hydro ultimately withdrew its proposal.

[63] CAC/MSOS/MH II-15 a).

[64] Hydro proposes to use marginal cost weightings derived from the from January 1999 to October 2004

Table 4-1
Generation Energy Marginal Cost Weightings[65]

Period[66]	Weighting
Winter Off-Peak	1.295
Winter On-Peak	2.101
Summer Off-Peak	1.000
Summer On-Peak	1.923

In order to determine whether Manitoba Hydro's marginal cost weightings adequately capture the range inherent in the SEP data set, it is prudent to consider what the marginal cost weightings would be if calculated separately for each month and for each of the on-peak, shoulder and off-peak periods[67]. The marginal cost weightings that resulted from this exercise are summarized in Table 4-2.

Table 4-2
Generation Marginal Cost Weightings by Month and Peak, Shoulder and Off-Peak periods

Month	Peak	Shoulder	Off-Peak
January	4.041	2.562	2.105
February	3.840	2.606	2.278
March	3.819	2.586	2.169
April	3.399	2.467	1.790
May	3.085	2.305	1.340
June	3.397	2.405	1.000
July	4.552	2.970	1.337
August	3.986	3.209	1.494
September	2.602	1.920	1.258
October	2.749	1.979	1.380
November	3.211	2.159	1.524
December	4.708	2.408	1.734

[65] Page 18, PCOSS 06. September 2005.
[66] Manitoba Hydro defines the Winter Season as the period from November 1 through April 30 and the Summer Season as May 1 through October 31 with on-peak in both seasons being the 16 hours from 07:00 thru 23:00 on weekdays (excluding holidays) and off-peak being the remaining hours per PUB/MH I-40 (a).
[67] This is accomplished by using the average inflation-adjusted SEP Prices ($/MW.h) from January 1, 1999 to October 4, 2004 provided in the response to CAC/MSOS/MH I –11 g) and determining the weightings for the resulting 36 periods (peak, shoulder and off-peak for each month) with the lowest of the reported 36 periods being indexed to 1.0 and all of the other periods being weighted based on their relative price ratios.

Table 4-2 indicates that this more refined method of determining time-differentiated weighting of energy results in a range of weightings from 1.000 to 4.708, compared to the range of 1.000 to 2.101 in Hydro's weightings from the PCOSS06. By collapsing the periods into simply 4 sets, Hydro's approach dampens the diversity and range of weightings developed and diminishes the ability of the weighting approach to properly reflect the relative energy values. Basing the PCOSS on this type of 12 month by 3 daily period weightings results in 36 periods or data sets that would need to be used in the analysis.

A potentially more pragmatic approach may be to use the sample weightings based on three daily periods (peak, shoulder and off-peak) and four seasonal periods (Spring – March-May, Summer – June-August, Fall – September-November, and Winter – December-February), as summarized in Table 4-3.

Table 4-3
Generation Marginal Cost Weightings by Season and Peak, Shoulder and Off-Peak periods

Month	Peak	Shoulder	Off-Peak
Spring	2.684	1.917	1.380
Summer	3.114	2.240	1.000
Fall	2.229	1.577	1.084
Winter	3.286	1.972	1.588

Table 4-3 indicates that this method results in a range of weightings from 1.000 to 3.286. This is a smaller range than the 32 period method but is considerably less coarse than the four period method.

The load data available for PCOSS06 does not permit investigation of the degree to which the 36 period approach provides materially different weightings than the 12 period approach. However, it is clear that using weighted averages based on only four periods will mute the ability of the weighting method to accurately represent the intended value of energy. Use of at least 12 periods is clearly preferable to Hydro's approach, if data requirements and practicality prevent the more refined full 36 period data to be used.

ATTACHMENT A – "SURPLUS" EXPORT REVENUES AND PAYMENTS TO SHAREHOLDERS

As noted in section 3 of this evidence, there is no apparent basis to use any export revenues today as a new "surplus" payment to the Province of Manitoba. Under any reasonable definition of "surplus" used in other jurisdictions to define the level of variable payments to government (outside of fixed charges such as water rentals), Manitoba Hydro has no surplus capital due to its current high debt:equity ratio and its total lack of other targeted reserves to deal with material risks such as drought.

Similarly, in response to MIPUG/MH II-5, Manitoba Hydro noted that while it was not aware of other Canadian utilities that credited net export revenues to functions other than generation and transmission, it was aware that other utilities had dividend policies that had the effect of reducing the amount of export revenue that would be available to be distributed to domestic ratepayers. In essence, Hydro has used this rationale to indicate that if the export revenue was reduced to some reference level by way of special dividends to the Crown, the existing established treatment of export revenue in cost-of-service is not problematic. In this regard, the Hydro rationale is not inconsistent with the concept of the identification of an export revenue threshold discussed elsewhere in this evidence.

The clear distinguishing factor, however, is the definition of "excess" export revenues in the cost-of-service that are above amounts that should properly be targeted to bulk power rates (as discussed in Section 3), and the degree to which this excess may not in fact be "surplus" to ratepayers needs such that it merits payment to the Crown as a dividend (where the current system has no surplus so long as there are no established drought reserves and Hydro's debt remains at the current high levels).

A summary of the dividend approaches for British Columbia Hydro and Hydro Québec, the two Canadian Crown utilities that are most comparable to Manitoba Hydro, is provided below. In each case, these dividends are established by legislation or other government directive. No similar framework exists in Manitoba at this time. Note that other jurisdictions with Crown utilities also consider capitalization in setting the amount of any surplus payment or dividend[68].

[68] This includes for example SaskPower and Yukon. SaskPower in particular was referenced in MIPUG/MH II-5. SaskPower however is a predominantly a thermal generation system – mostly coal – with limited export revenues compared to BC Hydro and Hydro Quebec (60% generation from coal and less than 8% total revenues from exports per SaskPower's 2004 annual report). SaskPower is a wholly owned subsidiary of the Saskatchewan Crown Investments Corporation (CIC) and that CIC has established a dividend policy for all the Crown Corporations within its purview. The dividends can be set within a range of 40 to 90% of net income plus special dividends that can be declared at any time. The dividends are based on achieving a capital structure of 60% debt. In Yukon, any dividends set according to Yukon Energy corporate policy cannot exceed a level that would reduce the capitalization of the utility below 60% debt (note however that these dividends similarly are not linked to export revenue and are not established in government policy, but by the Corporation's Board of Directors).

British Columbia Hydro

BC Hydro's policy framework for the payment of dividends is set out in Special Directives that are allowed under the specific BC legislation.

Special directive No. 2 to the British Columbia Hydro and Power Authority sets out the means by which an annual payment to the Provincial Government[69] is determined. Special directive No. 2 defines the distributable surplus as:

> Consolidated net income from all sources including electricity trade income, before any Rate Stabilization Account transfers, less interest during construction adjusted for depreciation to prevent double counting, as computed by B.C. Hydro according to generally accepted accounting principles and confirmed by B.C. Hydro's external auditors.

The special directive goes on to state that the B.C. Hydro Board of Directors shall confirm a payment to the Provincial Government for the previous financial year as determined by the following:

> The payment shall equal 85 percent of the distributable surplus for the financial year provided the debt/equity ratio of B.C. Hydro after deducting the payment is not greater than 80:20. If the payment would result in the debt/equity ratio exceeding 80:20, then the payment shall be reduced to the extent necessary to maintain the debt/equity ratio at 80:20 after deducting the payment.[70]

In contrast to BC, Manitoba Hydro does not at present have debt:equity level below 80:20. Manitoba Hydro has noted that at a minimum it would seek a debt:equity of 75:25, and further that it may potentially seek to lower this target once it has been reached. Further, Manitoba Hydro has no reserves to address rate stabilization as noted in the above BC policy.

Hydro Quebec

The Hydro-Québec Act[71] states in section 15.1 that:

> The dividends to be paid by the Company are declared once each year by the Government within thirty days after the transmission by the Company to the Government of the financial data relative to the distributable surplus. They are payable according to

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[69] This special directive dates from November, 1992 and from all accounts is still in force. BC Hydro's notes to its Consolidated Financial Statements for 2004/05 set out a description of the calculation of its payment to the Province that is consistent with this special directive.

[70] Paragraphs 5.1 and 5.2 in the special directive go on to discuss how payments to and from the Rate Stabilization Account will be used in the event that the distributable surplus differs from an annual rate of return that would have been achieved pursuant to special directive 8 to the British Columbia Utilities Commission.

[71] References to the *Hydro-Québec Act* in this section are taken from the latest unofficial version available at http://www.canlii.org/ updated December 2005.

> the terms and conditions determined by the Government. They cannot exceed, for a particular financial period, the distributable surplus as hereinafter established.

Section 15.2 goes on to provide the following definition:

> The distributable surplus for a particular financial period is equal to 75% of the total of the net operating income of the Company and of its net investment income for the same period, less the gross interest expenditure for the same period. Such income and expenditure are computed on the basis of the annual consolidated financial statements of the financial situation of the Company, according to generally accepted accounting principles.
>
> However, no dividend may be declared in respect of a financial period if the payment thereof would result in a reduction of the rate of capitalization of the Company to less than 25% at the end of that period.

Unlike Quebec, Manitoba Hydro is not at a 75:25 debt equity level at the present time. Similarly, without a fixed framework for addressing the risks of drought on ratepayers (as exists in Quebec[72]) Manitoba ratepayers must develop stabilization measures before the system “surplus” can be defined on an equal footing with Hydro-Quebec.

Manitoba’s Framework for Payments to the Crown

In some of the discussion surrounding the proper treatment of net export revenues, it has been noted that unlike these other Crown owned utilities, Manitoba Hydro does not pay an annual dividend to the Province. While in most years this is correct[73] it ignores the fact that there are many methods by which the Province can extract payments from a Crown utility. Comparisons between different Crown utilities of individual types of government charges are therefore likely to be incomplete or misleading. A more relevant way to assess the total value that a provincial government extracts from its Crown utility is to measure the total government charges paid by the utility compared to the total revenues of the utility.

Table A.1 summarises these charges for Manitoba Hydro as well as BC Hydro and Hydro Quebec

[72] An amendment to the *Act respecting the Régie de l'énergie and other legislative provisions* was passed with the main purpose to preserve the social pact as regards electricity and to guarantee that Québec consumers will continue to benefit from low and stable rates. To this end, the government has established a "heritage pool" giving Québec consumers access to 165 TWh/year of Hydro-Québec’s production and existing long-term supply contracts at a fixed price of 2.79 ¢/kWh.

[73] The Province of Manitoba has for example in the past directed that Manitoba Hydro submit a ‘special export payment’ to the Province, which in all practical ways is similar to a dividend.

Table A-1
Crown Utility Payments to the Province – Fiscal Years Ending 2002-2005 ($000)

	2002	2003	2004	2005
Manitoba Hydro				
Dividends	0	200	3	0
Debt Guarantees	68	70	67	68
Water Rentals	107	95	64	104
Land Rentals and Assessments	6	8	7	7
Corporate Capital Taxes	30	33	34	35
Sinking Fund Admin Fee	1	1	1	1
Payroll Tax	5	6	7	7
Assumed Provincial Mitigation Obligations		22	17	13
Total	**211**	**435**	**200**	**235**
Electric Revenue	1,385	1,354	1,287	1,508
Payments to Gov't as per cent of Electric Revenue	**11.6%**	**32.1%**	**15.5%**	**15.6%**
BC Hydro				
Dividends	333	338	73	339
Debt Guarantees	0	0	0	0
Water Rentals	228	258	246	234
School Taxes, Grants and other	140	142	142	143
Corporate Capital Taxes	26	3	5	0
Total	**727**	**741**	**466**	**716**
Electric Revenue	6,311	3,107	3,424	3,725
Payments to Gov't as per cent of Electric Revenue	**11.5%**	**23.8%**	**13.6%**	**19.2%**
Hydro Quebec				
Dividends	763	965	1,350	N/A
Debt Guarantees	188	186	165	N/A
Water Rentals	0	0	0	N/A
Tax on Gross Revenue	228	235	249	N/A
Municipal, School and other taxes	71	45	47	N/A
Corporate Capital Taxes and other taxes	281	296	324	N/A
Total	**1,531**	**1,727**	**2,135**	**N/A**
Total Electric Revenue	13,001	11,425	10,698	N/A
Payments to Gov't as per cent of Electric Revenue	**11.8%**	**15.1%**	**20.0%**	**N/A**

1. (*Source*: Manitoba Hydro 2002 Information per MH 2002 Annual Report; 2003-2005 Information per MIPUG/MH II-3 of PCOSS06; Water Rentals, Land Rentals and Assessments per MH 2003 and MH 2005 Annual Report.)
2. (*Source*: BC Hydro 2002 Information per BC Hydro 2002 Annual Report; 2003 Information per BC Hydro 2003 Annual Report; 2004 and 2005 Information per BC Hydro 2005 Annual Report)
3. (*Source:* Hydro Quebec 2002 and 2003 Information per Hydro Quebec 2003 Annual Report; 2003 taxes information restated per Hydro Quebec 2004 Annual Report; 2004 information per Hydro Quebec 2004 Annual Report)

An examination of Table A-1 indicates that Manitoba Hydro's payments to the Province, expressed as a percentage of total electricity revenues, ranged between 11.3% to 32.1%, well within the range of the two other utilities. Further, as noted above, the dividend component of the payments to each of BC and Quebec are subject to risks and limitations that are linked to the utility's performance. In the case of Manitoba, the payments are not so linked[74] .

[74] Water rentals can vary with the changes in river flows, however are not subject to the extreme swings that exist for dividends. For example, in 2003/04, the year of Hydro's worst drought on record, water rental payments dropped from a projected $97 million at median flows in IFF-MH01-1, to $64 million, whereas net income dropped to negative $428 million in that year (per MH's 2003/04 Annual Report).

ATTACHMENT B – COST-OF-SERVICE RESULTS SINCE 1992

In each of Hydro's rate reviews, a cost-of-service study has been produced which calculates the revenue cost coverage (RCC) ratio for each customer class and subclass – essentially the measure of the degree to which the rates charged to a customer class fairly reflect the net costs that the customer class imposes on Hydro's system. A RCC ratio of 1.00 or 100% illustrates rates that are equal to the calculated costs. A RCC ratio greater than 1.0 indicates that the revenues from a class are above the calculated costs to serve that class. In this case, costs are defined to include all revenues required by Hydro, including required contributions to reserves.

The PUB and Hydro have each recognized that RCCs should not vary from 100% to any marked degree (e.g., within a 'Zone of Reasonableness' of 95% to 105%) and that there is no basis to maintain a customer class RCC at above or below 100% on a consistent basis. The PUB used a Zone of Reasonableness (ZOR) prior to 1996 that equalled 90% to 110%, and revised this range to 95% to 105% in Order 51/96[75].

In each year, the RCC ratio can change for a number of reasons:

- **Changes in the relative level of rates:** This can include rate increases or decreases. In Order 7/03 the Board ordered rate decreases for certain classes in recognition of the fact that these classes had remained outside of the zone of reasonableness for long periods of time. In Order 101/04 the Board ordered rate increases for all classes in recognition of the impact of the recent drought on Manitoba Hydro's retained earnings.
- **Changes in the utility costs and the variables that are used to allocate costs:** This includes such variables as the system peak and total energy sales that are used to assign certain types of costs in the cost-of-service study.
- **Changes in the cost-of-service methodology:** Changes to Manitoba Hydro's cost-of-service study included certain revisions in 1999, those approved by the Board in Order 7/03 and those proposed by Manitoba Hydro in the current application.

[75] In Decision 51/96 the Board directed Hydro to undertake a study prior to the next GRA to address alternatives for solving the persistent problem of some rate sub-classes (specifically Residential Zone 3 and General Service Large >100kv) being persistently outside the Zone of Reasonableness. The Board also indicated that this study should assume a revised ZOR target of 95%-105%. See page 41 of Board Order 51/96

Table B-1 reviews the RCC ratios from 1991/92 to 2005/06.[76] The table shows a material variance in RCC ratios from 100% for many customer classes. Industrial customers (class GS Large >100kV in particular) have consistently had a RCC well above the zone of reasonableness defined by the Board. For 2005/06, the current cost-of-service methodology continues to show this variance.

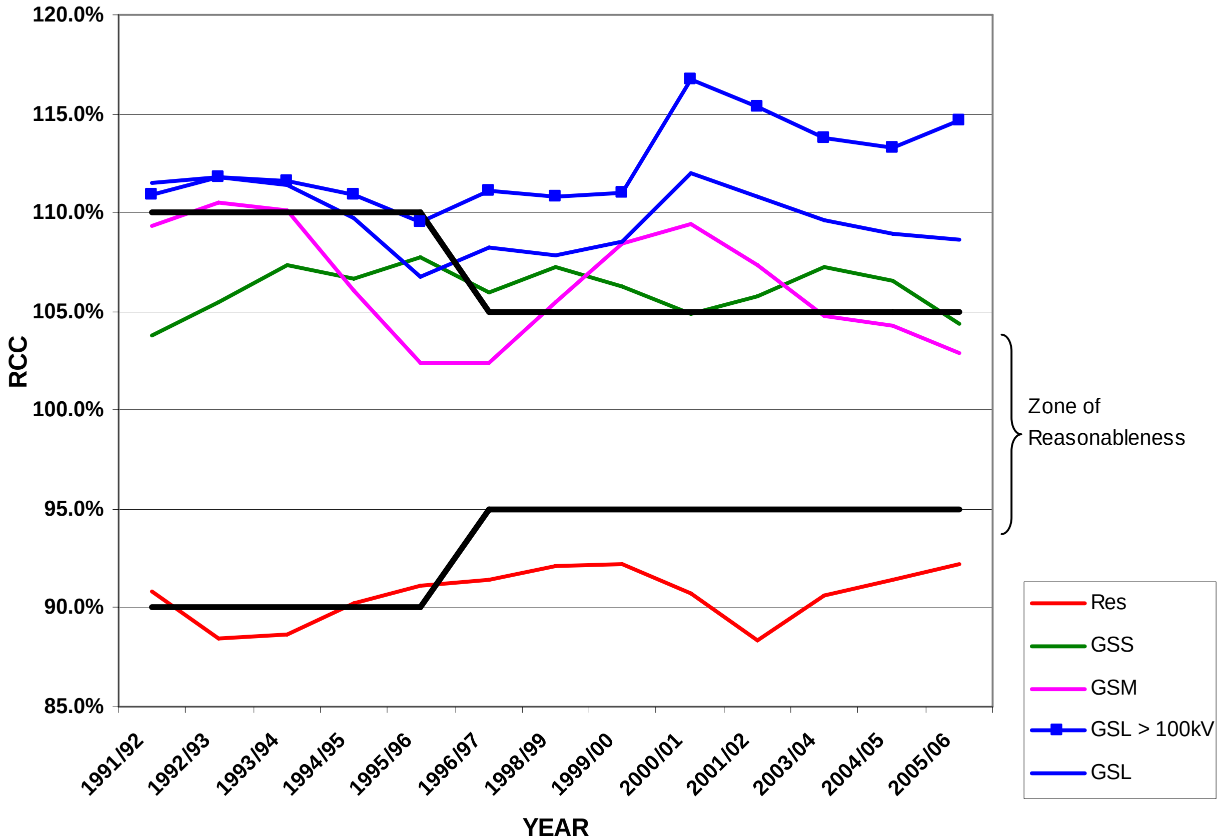
Table B-1:
Revenue Cost Coverage Ratios 1991/92 to 2005/06
(prior to Hydro's proposed COS methodology revisions)[77]

PCOSS	91/92	92/93	93/94	94/95	95/96	96/97	98/99	99/00	00/01	01/02	03/04	04/05	05/06
Res	90.8	88.5%	88.7%	90.2%	91.1%	91.4%	92.1%	92.2%	90.7%	88.4%	90.6%	91.4%	92.2%
GSSmall	103.8%	103.2%	105.6%	105.3%	106.2%	104.5%	107.7%	105.8%	105.4%	105.8%	107.2%	106.6%	104.4%
GSMed	109.3%	110.5%	110.1%	106.1%	102.4%	102.4%	105.5%	108.4%	109.4%	107.3%	104.8%	104.3%	102.9%
GSL<30 kv	109.0%	109.7%	109.5%	105.2%	98.5%	100.9%	101.4%	101.2%	102.6%	99.9%	99.9%	100.3%	94.0%
GSL30-100kv	122.5%	117.5%	114.8%	111.8%	109.4%	108.1%	110.3%	112.0%	118.8%	118.5%	109.5%	108.6%	109.4%
GSL>100kv	1.9%	111.8%	111.6%	110.9%	109.5%	111.1%	110.8%	111.0%	116.7%	115.4%	113.8%	113.3%	114.7%
GSCurtal							107.5%	110.3%	114.5%	111.3%	114.6%	112.6%	

This information is presented graphically in Figure B-1, which also indicates the ZOR as determined by the Board for the respective year.

[76] Using the consistent 1996 COS methodology, including the 1999 adjustments. 2005/06 RCC based on MH's current method.
[77] Data for 1991/92-1996/97 from MIPUG/MH/CR-2(b) from the 1996/97 GRA. 1998/99-2001/02 data from MIPUG/MH I-30 (a) from 2001/02 GRA. 2001/02 data represents the previous PCOSS methodology as stated in MIPUG/MH I-30 (a) from 2001/02 GRA. No PCOSS was available for 1997/98 or 2002/03. 2003/04 data from PUB/MH I-28(c) from 2003/04 GRA. 2004/05 data from MIPUB/MH I-21(f) from 2003/04 GRA. 2005/06 data from the current method from the current proceeding. 2005/06 GSL>100kv including curtailment customers.

Figure B-1
Revenue Cost Coverage Ratios 1991/92 to 2005/06
(prior to Hydro's proposed COS methodology revisions)



1. (*Source*: 1991/92-1996/97 data from MIPUG/MH/CR - 2 (b) from the 1996/97 GRA.)
2. (*Source:* 1998/99-2001/02 approved data from MIPUG/MH I - 30 (a) from the 2001/02 GRA.)
3. (*Source:* 2002/03-2003/04 data from PUB/MH I-28 (c)from the 2003/04 GRA.)
4. (*Source:* 2004/05 data from MIPUG/MH I-21(f) from the 2003/04 GRA.)
5. (*Source:* 2005/06 data from MH current method from the 2005/06 and 2006/07 GRA. GSL>100kv includes the curtailment customers)
6. (*Source:* No Cost-of-service Study was done for 1997/98 and 2002/03.)

A review of Table B-1 and Figure B-1 indicates that the relative changes to rates have not been successful in moving the major rate classes to within the revised ZOR target of 95%-105%. Hydro's current filing, consistent with the 2001 and 2004 filings attempts to address this issue by focusing on revising the approach used to measure costs, rather than through rate rebalancing.

In response to MIPUG/MH I-6, Manitoba Hydro provided a table showing the change to RCC ratios by class for each of the major revisions proposed by Hydro in the current proceeding. The RCC impacts of the changes are summarised below in Table B-2.

Table B-2

Changes to RCC Ratios by Class as a result of moving from the Current Method to the Method Recommended by Hydro [78]

	Residential	GSS ND	GSS D	GSM	GSL 0-30	GSL 30-100	GSL >100	S/L
Current Method	**92.2%**	**103.1%**	**106.0%**	**102.9%**	**94.0%**	**109.4%**	**114.7%**	**105.2%**
Add Firm Export Class	-0.6%	1.4%	0.8%	0.0%	-0.5%	0.8%	1.5%	0.0%
Functionalize Transmission into Domestic and Export	0.2%	0.1%	0.0%	0.1%	0.0%	-0.5%	-0.7%	-0.2%
Classify Generation as Energy (E10)	0.6%	0.3%	0.2%	0.4%	-0.2%	-2.0%	-2.5%	-1.0%
Allocate Generation on Weighted Marginal Cost (E12)	-0.1%	-0.6%	-0.5%	-0.6%	-0.5%	1.5%	1.7%	1.3%
Allocate Exports on share of total allocated cost	4.7%	3.1%	-1.1%	-2.2%	-2.7%	-7.7%	-11.5%	1.8%
Total Impact on RCCs	4.8%	4.3%	-0.6%	-2.3%	-3.9%	-7.9%	-11.5%	1.9%
Recommended Method	**97.0%**	**107.4%**	**105.4%**	**100.6%**	**90.1%**	**101.5%**	**103.2%**	**107.1%**

[78] Taken from MIPUG/MH I-6

Focusing on the large industrial class relevant generally to MIPUG members (GSL >100 kV), Table B-2 indicates that the changes in COS methods dramatically reduce the RCC under current rates from 114.7% (i.e., large industrial customer class rates are 14.7% greater than allocated costs of service, revenues in excess of costs of $32.7 million) to 103.2% (i.e., these same rates for this class are only 3.2% greater than the newly allocated costs of service and revenue in excess of costs of $6.2 million). Table B-2 further demonstrates that all of the 11.5 percentage point reduction in the RCC for GSL > 100 kV is due to new proposals to allocate "excess" export revenues – the net effect of all of the other four major changes is neutral with respect the RCC of this class.[79]

Overall, a review of Table B-2 indicates that by far the single biggest change, in terms of impact on RCC for all of the rate classes is the change in the allocation method for net export revenues. Further, the impact of the change in allocation of net export revenues generally benefits Residential and Small General Service Non-Demand customers while negatively impacting other General Service customer classes. This table supports Hydro's assertion that the treatment of export revenues is the "key issue" in its cost-of-service proposal.

[79] However the level by which rates exceed costs is lowered by approximately $3.7 million as a result of the other changes, though because of changes in the way costs are measured this does not impact the overall RCC.

ATTACHMENT C – RATE DESIGN

The process of setting rates for a regulated cost-based utility involves three distinct steps – determining a revenue requirement, developing cost-of-service allocations to each customer class, and developing a rate structure to collect the cost-of-service. The process of cost-of-service allocation is driven primarily by historic and present system characteristics and use, and the need to fairly reflect cost causation. In contrast, rate design is focused on the signals sent to the consumer – that is to say, focused on matters distinct from the cost-of-service cost causation focus.

Although rate design is not a main focus of the present proceeding, many of the issues purported to be addressed by Hydro's proposals are in fact related to rate design and not cost-of-service. This attachment sets out the basic framework for utility rate design and discusses how many of the issues raised by Manitoba Hydro in the present proceeding are driven by inadequate rate designs, not by failures of the cost-of-service methodology.

Similar to cost-of-service, there are standard and longstanding principles and precedents related to the topic of rate design, going back to developments over perhaps a century including regulation of railway tariffs and other monopolies. Summary material on the development of rate design principles is often sourced to James Bonbright's "Criteria of Desirable Rate Structure". These standard rate design criteria are entirely consistent with Manitoba Hydro's own rate design criteria:

a. To achieve Manitoba Hydro's full Revenue Requirement for General Consumers.

b. To collect revenue from each customer class which bears a reasonable relationship to cost allocated to serve that class using PUB approved cost-of-service study methods.

c. To put in place rate structures and accompanying processes of applications, billing, metering and service extension which assure equitable treatment of customers both within and between rate classes.

d. To promote efficient use of power and energy.

e. To have the practical attributes of:

    - stability and continuity of rates (gradualism of change)
    - minimum of unexpected adverse change
    - enhancing revenue stability and predictability
    - freedom from controversy as to proper application

- feasibility of application
- public acceptability
- simplicity and understandability

While this list of rate making objectives was set out in the 1995 General Rate Application[80] , Hydro has recently confirmed that these objectives remain applicable[81].

One of the key issues raised by Manitoba Hydro in the current proceeding, as noted earlier in this evidence, is the degree to which having domestic rates lower than rates in adjacent jurisdictions fails to send a proper price signal and therefore leads to wasteful consumption of electricity (NERA has similarly cited the gap between domestic rates and export prices as a matter for consideration[82]).

Many utilities and regulators have examined the issue of how to ensure that rates reflect proper price signals to customers. In the context of the current proceeding, relevant recent assessments and experience with respect to rate design for industrial customers are noted below.

The basic theme that runs through the rate design structures reviewed below is that compared to a standard level of use, as long as an existing customer faces cost changes in line with what is defined as "marginal cost" for ***incremental*** increases or decreases in load, the price signal being provided to the customer is efficient. This gives the customer a clear indication that growth in consumption related to decreases in efficiency will cost a higher rate than the average, and similarly that decreases in consumption due to increased conservation, DSM, or self-generation will reduce the customer's bill such that they are receiving a full credit for the incremental value of the energy they save. In short, if Hydro is willing to purchase new power, or put in service new assets, or upgrade existing assets (Supply Side Enhancements or SSEs), or operate DSM programs to the extent that these can provide new kW.h at a price below 6.7 cents/kW.h for long-term firm power[83], then the rate design should provide an encouragement to existing customers to similarly reduce their load or self-generate to secure credits in this order of magnitude. Under the existing industrial rate in Manitoba, such credits are not available. However, under each of the rate options noted in this section, this price signal is achieved (irrespective of the cost-of-service approach in place).

[80] See pages 81 and 82, Question F: Rate Design of the November 1995 GRA.
[81] In response to MIPUG/MH I-28 b) from the 2004 General Rate Application, Manitoba Hydro indicated that the rate design proposed in the 2004 Application was wholly consistent with the objectives outlined in the 1995 GRA and that those objectives remained relevant in 2004.
[82] Pgs 33-34 Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies. NERA. 2004.
[83] Refer to the response to MIPUG/MH I-10. This figure reflects MH's stated marginal cost for conserved energy levelized over a 20 year period (2005 $CAN).

Manitoba Hydro Time-of-Use and Inverted Electric Rate Structures Study

In a 2005 report for Manitoba Hydro, NERA noted the advantages of ensuring that customers are exposed to marginal cost price signals but also correctly noted that "Pricing all service at marginal cost would produce too much revenue".[84] With this in mind, NERA examined several different options for implementing time-of-use and inverted block rate structures in Manitoba.[85] In the report, NERA noted that:

> One approach to commercial/industrial inverted rates is to define a customer-specific first block that is based on consumption level in a specified year ("customer baseline" or "CBL") and does not change except under extraordinary circumstances (such as a major change in scale of operation). Under this approach, each commercial or industrial customer pays the low price for a fixed percentage of baseline usage, and the higher tail-block price for all additional usage. This places large and small customers on a more equal footing.[86]

NERA went on to state in its conclusions that "For equity and competitive reasons, inverted block structures for General Service customers should ideally define the first block in terms of a percent of CBL…"[87].

Hydro has not yet proposed any rate structures along the lines of the NERA report.

British Columbia Hydro Stepped Rate Proposal

In 2003, the British Columbia Utilities Commission ("BCUC") received a proposal from BC Hydro regarding a Heritage Contract, Stepped Rates and Access Principles. The Stepped Rate component addresses rate design and price signals for large industrial customers. Prior to any implementation of the stepped rate proposals reviewed by the BCUC, the application was subject to extensive and numerous workshops and other consultation with industrial customers and other stakeholders.[88]

In its report on the 2003 proposal[89], the BCUC summarised certain discussion and principles examined during the review, including:

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[84] Page 4, Review of Time-of-Use and Inverted Electric Rate Structures for Application in Manitoba. NERA. 2005.

[85] Review of Time-of-Use and Inverted Electric Rate Structures for Application in Manitoba. NERA. 2005.

[86] Page 30, Ibid.

[87] Page 70, Ibid.

[88] See for example, Page 3-2 of the BC Hydro Transmission Service Rate Application from March 2005 which notes 12 meetings over a 12-month period with the Joint Industrial Electric Steering Committee consisting of most of BC Hydro's largest industrial customers. It is noted that these meetings dealt with a variety of topics around the design and timing of the implementation of Stepped/TOU rates. BC Hydro states in this document that because of these discussions it has "….been able to craft a more robust rate application". BC Hydro also notes that it conducted four workshops to engage a broader group of customers beyond the JIESC.

[89] BCUC Report and Recommendations in the matter of British Columbia Hydro and Power Authority and An Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access. October 17, 2003.

a. By proposing that the stepped rate be a mandatory tariff, BC Hydro is applying the principle that customer decisions at the margin should respond to the cost of new supply, rather than to an existing embedded cost rate or a blended rate of old and new costs.[90]

b. BC Hydro's principle of margin neutrality is intended to ensure that bill credits granted to customers for their energy savings do not exceed BC Hydro's risk-adjusted value of the saved energy, and that the incremental costs and risks of acquiring new supply are recovered in bills sent for additional growth. That is, BC Hydro requires margin-neutrality to ensure that a stepped rate design does not shift costs to non-participating customers.[91]

c. A simple two-tiered rate design requires decisions about the rate for each of Tier 1 and Tier 2 and a percentage of Customer Baseline Load ("CBL") to be billed at each rate.[92] With respect to the selection of each of these elements of the stepped rate the BCUC findings can generally be summarised as follows:

1. The Tier 2 rate should reflect the long-term opportunity cost of new supply defined with reference to BC Hydro's expected resource acquisition costs.
2. A 90/10 split (between Tier 1 and Tier 2) ensures that the Tier 2 quantity is sufficiently large to satisfy the Energy Plan's objective of providing better price signals for conservation and energy efficiency while not so large as to expose BC Hydro to significant price or volume risk.
3. With the Tier 2 rate and the Tier 1/Tier 2 Split specified, the constraint of revenue neutrality for transmission level customers determines the Tier 1 rate.
4. The ultimate design of a two-tiered stepped rate that adheres to the principle of revenue neutrality requires that a CBL be determined as a reference point for historical energy consumption levels. Should stepped rates be implemented, the Commission should approve CBLs and subsequent adjustments to them, and resolve any associated disputes. As part of its proposal, BC Hydro should specify the mechanism under which new load or new customers would be incorporated into a stepped rate pricing structure.[93]

[90] Page 39, Ibid.
[91] Ibid.
[92] Page 40, Ibid.
[93] In its August 2005 Order respecting BC Hydro's 2005 Transmission Serve Rate Application, the BCUC approved the CBL Determination Guidelines as set out in the Negotiated Settlement. Those Guidelines included, in section 4.1.2.2, provisions for adjusting the CBL for plant capacity increases as a result of capital investments.

Yukon Industrial Primary Rate Schedule 39

The marginal cost of supply in Yukon when major industrial customers are operating is diesel fuel. The Yukon Energy industrial rate offering sets out the means to define a "Base Load Energy" amount for each customer. Energy rates above this base load energy amount are charged at the forecast marginal cost of diesel, and at embedded costs below this level such that the customer pays 100% of their cost-of-service.

Similarly, Yukon Energy's wholesale rate schedule (for power provided at transmission voltages to the local distribution utility) provides a means to enable an "Energy Reconciliation Adjustment" which similarly ensures the customer is paying (or receiving credit for) the full marginal costs of diesel fuel generation for increases or decreases in consumption above a defined threshold, effectively set at 90% of the customer's total forecast energy requirements.

Summary of Stepped Rate Proposals

A brief review of recent studies and regulatory review for Canadian utilities indicates that there can be benefits to both the utility and customers from developing a stepped or inverted rate design. Key considerations or findings with respect to the design of such rates include:

1. The rate needs to be designed in consultation with the customer, particularly in regards to determining reasonable definitions of "growth" as opposed to "baseline use".

2. The rate should clearly ensure it is not a barrier to growth or development of new loads in the jurisdiction (i.e., not treat 100% of new customer loads as "growth"). In this regard it is similar to residential rates, where new customers do not pay the new higher "inverted rate" for 100% of their consumption.

3. The second tier of the rate should be set at or close to the utility's marginal cost.

4. A reasonable cut-off between the first and second tiers needs to be developed that exposes a reasonable portion of load to the marginal cost rate.

5. Consideration needs to be given to conditions under which it would be appropriate to adjust the base load reference point, such as when a customer undergoes a significant increase or decrease in load due to a change in the character of the operation.

Implementation of Stepped Rate Proposals

As evidenced by the experience in BC, developing stepped rate proposals involves addressing many details that are of keen interest to customers. In the case of BC, this consultation was ultimately quite detailed and lengthy to ensure full meaningful participation by impacted customers.

Mr. Osler and Mr. Bowman in the evidence prepared for MIPUG in the 2004 GRA, summarized that a similar consultation program aimed at stepped rates for industrial customers in Manitoba was already long overdue, as follows:

> Most importantly for this proceeding, however, is that with respect to industrial customers, Hydro provides no new proposals or indications that it is contemplating rate designs that may improve the price signals to customers (either in response to Board Order 51/96[94], or perhaps like recent rate design modifications proposed in similar jurisdictions[95]). In particular, other jurisdictions have recently been engaging in cooperative efforts to redevelop industrial rate designs to attempt to increase the price signals on the "marginal" consumption, or the part of the load that is most subject to management (i.e., conservation) by the customer (to both result in increased costs from short-term load excursions, and cost savings to the customer from incremental efficiency improvements). These types of proposals are not easily achieved, and take significant time for debate and negotiation between the utility and its industrial customer representatives (as well as potential debate before the regulator). For example, the proposals have to address the ability to charge higher rates for short-term load excursions or wasteful use, but at the same time not penalize the growth of Manitoba companies. Given that Hydro has still not responded to the Board's 1996 direction to develop a comprehensive rate policy[96] which was to include "consultation with interested parties", it would seem timely to ensure the Board's directives to Hydro in this proceeding are aimed at developing a cooperative proposal over time (between Hydro and large consumers) to refine rate designs to address Hydro's concerns with respect to price signals.

No consultation has apparently been undertaken by Hydro since that time. Given the nearly 10 years since Hydro was first ordered to consult with customers towards a rate design of this type, it seems timely that the consultation towards a more efficient rate structure now be directed to occur.

[94] Board Order 51/96 at page 43 summarizes Hydro's perspective that "the most efficient price signals are those which are related to the relevant incremental costs" and further "…rate design incorporating incremental costs typically applies to those elements of a rate structure where customers' use decisions are most sensitive to price. These are typically for the last block of energy in a demand/energy rate structure." The Board, in that Order, directed Hydro to report on the implications of incorporating incremental costs into rate design.

[95] On example may be the BC Hydro stepped rate proposals, although in each case these would need to be made appropriate for the Manitoba environment.

[96] A directive dating back to Board Order 51/96 from the 1996 GRA.

1 ## ATTACHMENT D – RESUMES

PATRICK BOWMAN
CONSULTANT

EDUCATION: **University of Manitoba**
MNRM (Natural Resource Management), 1998

Prescott College
BA (Human Development and Outdoor Education), 1994.

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory reviews of electrical and gas utilities in four Canadian provinces. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability.

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Prepare analysis of major capital projects, financing mechanisms to reduce “rate shock” to ratepayers, as well as revenue requirements.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government round table on competitiveness of Yukon economy. Coordinate development of options for government rate subsidy program. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and support regarding General Rate Application. Assist in preparation of evidence, filings before the Northwest Territories’ Public Utilities Board, and related issues. Appear before PUB as expert in cost of service and rate design matters, and on system planning (Required Firm Capacity) review.

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures and surplus energy rates.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters.

- **For NorthWest Company Limited,** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate review before Utility Rates Review Council.

- **For Nexen Chemicals, Inc. (2000)**, review options for subscribing to curtailable service rates.

- **For Columbia Power Corporation/Columbia Basin Trust and Municipal Interveners (2000),** review evidence and prepare analysis on major transmission line project for Public Convenience and Necessity hearing before the British Columbia Utilities Commission.

- **For the City of Yellowknife (1999)**, prepare preliminary analysis of policy options and planning process for development of a municipal piped propane distribution system.

- **For the Government of the Northwest Territories (1999)**, prepare analysis of policy alternatives to facilitate supply of natural gas to local communities in the event of a Mackenzie Valley pipeline being constructed.

- **For INCO Manitoba Division (1998-present)**, prepare analysis of energy costs under various alternative industrial rate options. Provide recommendations on preferred energy rate options.

Socio-Economic Impact Assessment and Mitigation

Provide support in development of local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Socio-economic assessment work related to forestry planning in Manitoba and Saskatchewan. Support to two local communities in development of negotiation position for resolving outstanding compensation related to hydro projects in Northern BC. Also conducted assessment of socio-economic impacts of policy options for floodplain management, and strategic planning for resource management board.

- **For Northwest Territories Energy Corporation (2003-present)**, provide analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002-2004):** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review assessment of options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

- **For Manitoba Hydro Mitigation Department (1999-2002)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

- **For International Joint Commission (1998)**, analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of other floodplain management policies.

- **For Nelson River Sturgeon Co-Management Board (1998 and 2005)**, an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of the Northwest Territories **Yellowknife, NT**

1996 - 1998 *Land Use Policy Analyst*

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Natural Resources Institute **Winnipeg, MB**

1996 - 1998 *Researcher*

Conducted research on surface rights allocation and access for mining, with particular emphasis on implications of government actions undermining mineral rights tenures. Also undertook analysis of Manitoba's Registered Trapline System and implications for Aboriginal trappers; also, an economic assessment of the property rights system inherent in the provincial Registered Trapline System policy and its implications on efficiency in allocation of the furbearer resource.

PUBLICATIONS:

G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

Legal Framework for the Registered Trapline System in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997

Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches. Natural Resources Institute. (Masters Thesis). 1998

Electrical Rates in Yukon. Submission by Yukon Development Corporation to Yukon "Government Leader's Economic Forum Series" on Tax Reform and Competitiveness. 1999.

Review of Red River Basin Floodplain Management Policies and Programs. Prepared for Red River Basin Task Force of the International Joint Commission. 1998.

ANDREW McLAREN
CONSULTANT

EDUCATION: **Natural Resources Institute, University of Manitoba**
MNRM (Master's of Natural Resources Management), 1999

University of Manitoba
Bachelor of Science (Environmental Science), 1996

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

2000 - Present *Research Analyst/Research Consultantl Consultant*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy and water resource management fields.

Utility Regulation

Conduct research analysis for regulatory reviews, primarily of electric utitilies. Prepare evidence and regulatory filings and review testimony for regulatory proceedings.

- **For Northwest Territories Power Corporation (2000-present)**, provided technical analysis regarding the Corporation's General Rate Applications and ongoing regulatory support. Responsibilities have included the preparation of evidence and filings before the Northwest Territories Public Utilities Board. Other responsibilities have included assistance on economic evaluation of major capital projects.
- **For Manitoba Industrial Power Users Group (2001-present)**, prepare analysis for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Review and analyse alternative industrial rate options from other jurisdictions in Canada and the U.S.
- **For Yukon Energy Corporation (2001-present)**, Review secondary and interruptible industrial sales options from other jurisdictions in Canada. Provide technical analysis and support regarding applications to the Yukon Energy Board.

- **For Yukon Development Corporation (2001-present),** prepare analyses of rate options and rate subsidy program impacts as well as contribute to discussion papers on modifications and options for on-going subsidy program.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** assist in the preparation of analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

- **For NorthWest Company Limited (2004-2005),** review rate application and rider applications, provide analysis and filing before the Nunauvt Utility Rates Review Council.

- **For Government of Northwest Territories (2005),** prepare modeling tools and provide analysis and discussion paper on forecast spending for the Territorial Power Support Program.

Socio-economic Impact Assessment

- **For Manitoba Floodway Authority (2003-2005)**, managed the field program for the socio-economic impact assessment of the proposed Floodway Expansion, a project to improve flood protection for the City of Winnipeg. Responsibilities included planning, conducting and supervising field work and key-person interviews, analysis of potential socio-economic pathways of environmental effects based on the results of engineering and bio-physical studies and drafting and editing the socio-economic chapter of the Floodway Expansion environmental impact statement. Participation in the project also involved responding to interrogatories and supporting expert testimony on socio-economic impacts at the Clean Environment Commission hearings on the project.

- **For Province of Manitoba (2000-2002),** conducted quantitative and qualitative assessment of socio-economic impacts related to proposed flood control alternatives for the City of Winnipeg. Included key-person interviews with stakeholders and presentation of results at public meetings.

- **For two Northern British Columbia First Nations,** Provide support and analysis related to potential claims for past and ongoing effects from major hydroelectric development. Review economic casework related to changes to energy supply options for the communities including potential for interconnecting to the BC Hydro grid or development of local hydroelectric or wind generation.