PRE-FILED TESTIMONY OF
P. BOWMAN AND A. McLAREN
IN REGARD TO MANITOBA HYDRO 2008
GENERAL RATE APPLICATION

Submitted to

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

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TABLE OF CONTENTS

List of Tables

List of Figures

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 A.

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's ("Hydro") filed material regarding its 2008 General Rate Application ("Application" or "GRA") that are of interest to industrial customers. In particular, the scope of the review includes the following, taking into account normal regulatory review procedures and principles appropriate for Canadian Crown-owned electric power utilities:

- Financial performance from the time of the last Board review, forecast financial performance within Hydro's current ten-year projections, necessary levels of reserves and the rate of progress in establishing reserves and appropriate overall rate adjustments that should be required in light of these financial results;
- Cost of Service study ("COSS") methods and results; and
- Proposed rates for general consumers and in particular industrial class customers.

This pre-filed testimony does not deal with matters related to the General Service Large New or Expanded Loads rate set out at Tab 10.3 of Hydro's filing.

In preparing this testimony, the following information has been reviewed:

- The Hydro GRA dated August 1, 2007, including appendices.
- The responses to the first and second round Information Requests to Hydro.
- To a limited extent, Hydro's evidence in the 2006 Cost of Service proceeding and earlier rate hearings as they relate to the current proceeding.

The evidence is presented in the following sections:

- Section 2 provides an overview of Hydro's filing and requested approvals.
- Section 3 provides a review of financial results and proposed increases to overall levels of rates.
- Section 4 provides a review of the Cost of Service study and rates for general consumers.
- Section 5 provides a review of industrial, cost-based rate design.

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

1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The evidence in this proceeding reflects a stark contrast with respect to the level of confidence that the Board can be afforded amongst the three major hearing components of the Application (Revenue Requirement, Cost of Service, and Rate Design).

Following a period of concern, since 2001, that Hydro's **Cost of Service ("COS")** methodology was outdated, the recent extensive hearing on COS can now provide the Board with comfort that it has appropriate and adequate information to make decisions regarding relative level of rate adjustments between the various classes. The uncertainty which existed over the past series of proceedings has been resolved[1] and the result is a useful, reliable analytical tool.

The same cannot be said with respect to **Revenue Requirement**. The guidance available to the Board with respect to Hydro's revenue requirement and overall level of rates in this proceeding is not meaningful (or, as was recently said with respect to COS before the recent methodology review, is in a state of 'flux'). The recent practice (since 2001) of focusing primarily on Hydro's debt:equity targets to set the long-term level of rates cannot be usefully applied into the future, for two reasons.

First, Hydro's total capital (the denominator in the debt:equity ratio) is set to grow by massive amounts related to major new projects. As a result, current debt:equity targets will not likely be reached for decades, or in the event they are attained, will indicate that current ratepayers are seeing rate increases related to major new capital projects advanced for export reasons, contrary to the clear policy objectives for these projects. As such, this financial target (even if valid as a target for the Corporation's Board of Directors) is much too coarse to use as an analytical tool for the purposes of setting rate levels.

Second, equity (as the term is used in the target) is equated to Hydro's Retained Earnings. Reserves are required to protect ratepayers from major risks, including but not limited to drought, as a valid regulatory objective. Hydro's Retained Earnings are ineffective for this purpose as they are not directly overseen by the Board, and do not provide the Board with a sufficient level of control. As the Board largely only sets Hydro's rates (and thereby affects Hydro's revenues), the Board's decisions have an insufficient linkage to the level of Hydro's Retained Earnings. When Hydro's costs escalate beyond levels with which the Board ought to have comfort (as they have in the present forecasts), any higher rates approved by the Board for the purposes of building protection for ratepayers in the form of reserves do not arise as "reserves" as intended. In this situation, the Board is caught between raising rates further, which simply reaffirms Hydro's cost levels, or cutting rates, which is not prudent in light of present "reserve" levels.

In short, recent practice has been for the Board to take on the unenviable task of making it their concern that Hydro has insufficient retained earnings. Regulation must now evolve to having the Board focus on

[1] This is not to say that there does not remain some level of disagreement regarding the methodologies employed in the Cost of Service study. For example, there remains concern that allocation of net export revenue to distribution functions has no analytical merit, as it reflects no linkage in the design or operation of the system. Conversely, Hydro notes competing concerns that the Board's approved approach to measuring the cost of export revenues and in particular its allocation of fixed system costs to "opportunity" export sales. However, as these issued were extensively debated before the Board and the methodology was only recently confirmed, these issues are not suitably front-and-center in the present proceeding.

reserves that it can adequately assess, control and direct, and leave the Corporation's net income and capital structure as a matter for the Corporation to manage.

With respect to **Rate Design**, Hydro's application fails to make sufficient progress on moving the major classes (including Industrial) towards greater pricing and efficiency signals. Efforts are required to ensure that further rebalancing, both within each class and among the classes occur in a measured way beyond solely the single rate adjustment noted in the present Application. Hydro also needs to turn its attention promptly to the development of a contemporary industrial rate design (such as revenue neutral stepped rates, and potentially time of use) to ensure that customers are provided all necessary opportunities to conserve (and consequently reduce their power bills) under an appropriate price signal.

As specific key recommendations, this submission addresses the following matters:

1) The use of a debt:equity target to guide rate increases should be discarded. The Board should target a major review of alternatives to establishing appropriate protected regulated reserves, as may be permitted within the appropriate legislation.

2) For this proceeding, a 2.9% rate increase overall at this time may be justified, on a go-forward basis from the date of the Board's Order, primarily to establish a measured predictable rate adjustment regime. Any future overall increases to the level of Hydro's rates should be predicated on completing the review noted in (1) and successful establishment of regulatory reserves under the direct oversight of the Board.

3) The COS study should be adjusted to remove the present double counting with respect to DSM costs.

4) The specific level of rate adjustments to each of the various classes should reflect the results of the COS analysis, with an eye to both pre- and post- net export revenue allocation. With respect to pre-export revenue allocation, consideration should be given to evolving over time a system where Hydro's rates are not credited with net (i.e., "above cost") export revenues within the COS study, but instead these amounts are used to build necessary regulated ratepayer reserves (until such reserves have reached the necessary level).

5) Hydro should be directed to implement a second rate adjustment effective April 1, 2009 on a corporate-wide revenue neutral basis, to continue inter-class progress towards reaching suitable revenue:cost ratios within five years, as well as intra-class rebalancing of the various rate components.

Other recommendations or observations are contained in the appropriate sections of this submission.

1.2 OVERVIEW OF 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 the following companies:

- Canexus Limited (Brandon)
- Vale Inco Limited (Thompson)
- Hudson Bay Mining & Smelting Co., Ltd. (Flin Flon)
- Tembec Inc. (Pine Falls)
- Enbridge Inc. (Southern Manitoba)
- Gerdau Ameristeel (Selkirk)
- ERCO Worldwide (Hargrave)
- Koch Industries, Inc. (Brandon)
- Tolko Industries, Ltd. (The Pas)
- Griffin Canada Inc. (Winnipeg)
- TransCanada Keystone Pipeline GP Ltd (Southern Manitoba)

These companies annually purchase approximately 5,200 GW.h of electricity at a cost of over $100 million from Hydro (approximately 25% of Hydro's domestic sales)[2]. In 2005, MIPUG prepared and distributed an economic impact study[3] of member companies. According to the information available at the time the economic impact study was undertaken, MIPUG members employ over 4,500 people in total, 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.
- 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.

[2] A total industrial load of 5,200 GW.h on 20,555 GW.h of Manitoba supply for 2006/07 as reported at page 101 of Manitoba Hydro's 2006/07 Annual Report.

[3] The Economic Impact Of The Manitoba Industrial Power Users Group (August, 2005).

- 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 OVERVIEW OF HYDRO'S FILING

Hydro's August 1, 2007 filing for rates effective April 1, 2008 seeks approval for a one year rate increase of approximately $31 million (approximately 2.9%) on an annualized basis[4], plus final confirmation of a previous interim rate increase of 2.25% effective March 1, 2007.[5] In support of the request Hydro cites that "The proposed rate increase is required to maintain reasonable progress towards the attainment of the Corporation's financial targets".[6] Hydro has not sought interim approval of the 2.9% rate increase for April 1, 2008, and based on past practice before this Board, it is assumed that any rate change ultimately approved will apply only on a go-forward basis following the Board's Order.[7]

In addition to the 2.9% rate adjustment, Hydro's application seeks approval of a new General Service Large – New or Expanded loads rate that is variously quoted as driving added revenue to Hydro of $12 million[8] to $15 million[9] in 2008/09 on an annualized basis. As noted in the Introduction, the proposed new rate is not addressed in this submission.

With respect to the relative level of class rates, Hydro's filing requests approval of 2.9% increases to all classes of customers with the exception of Area and Roadway Lighting at 1%.

Hydro also seeks final approval for various interim orders related to the Surplus Energy Program and the Curtailable Service Program, as well as minor modifications to the terms and duration of these programs.

The recent Manitoba Hydro hearing before this Board on matters related to Hydro's Cost of Service Study, and the Board's Directives flowing from that Order, are contained in the Prospective Cost of Service Study ("PCOSS") filed with this application at Tab 11. This is the first regulatory review of the implementation of the Board's directives from the proceeding.

Hydro has filed a number of studies related to alternative rate designs, either with respect to overall structure (such as inverted rates) or timing (time of use). With respect to these alternatives, the present Application includes only modest changes to move Residential towards an inverted structure and changes to begin to consolidate certain General Service Small and General Service Medium classes.

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[4] This amount of revenue is forecast in the event the rate changes were implemented April 1, 2008. Given the current schedule for the proceeding, it does not appear that final rates can be approved for April 1, 2008.

[5] Approved on an interim basis in Board Order 21/07.

[6] Tab 1 page 2.

[7] For example, Order 101/04 issued on July 28, 2004 approved new rates effective August 1, 2004 notwithstanding Hydro's filing in that case seeking rates effective April 1, 2004. Similarly, Board Order 20/07 issued February 28, 2007 approved rates to be effective March 1, 2007, notwithstanding Hydro's application seeking rates to be effective February 1, 2007.

[8] Appendix 10.1

[9] PUB/MH-I-96(i)

Particular items of note in respect of load and system supply in Hydro's forecasts include the following:

- With respect to loads in 2008/09, the current 2007/08 Power Resource Plan[10] indicates total firm domestic loads approximately equal to what was forecast in the 2004/05 Power Resource Plan.[11]

- Hydro's planning now requires Conawapa (4550 GW.h/year dependable) by 2021/22 and this in-service date is only made possible by delaying the retirement of Selkirk Thermal (1060 GW.h/year) one year to 2020/21 from the earlier plan of 2019/20. No Keeyask generation (2880 GW.h/year dependable) is included in the Power Resource Plan, although planning costs for this project continue in IFF07-1.

- The entire Power Resource Plan is predicated on Brandon thermal unit #5 (837 GW.h/year) being available through 2018/19. Absent this assumption, firm energy supply deficits arise for much of the period from the date of assumed retirement of this plant through the scheduled termination of the NSP 500 MW sale in 2014, at which time firm supply obligations are reduced to the point where the system again has sufficient resources.[12]

- Resources from 400 MW of "committed" wind (including the 100 MW already developed) are included in the Plan; no supply from possible other uncommitted renewable power sources (such as further wind, or biomass) are noted.

- The 2007/08 Electric Load Forecast (on which the 2007/08 Power Resource Plan is based) appears to reflect no reductions in Industrial Load Growth related to the proposed New or Expanded Industrial Rate.[13] The 2006/07 Power Resource Plan indicates that in the event a new rate of this type is approved, loads could be lower by 1000-2000 GW.h[14]; no Power Resource Plan alternative scenarios incorporating the rate of this type are presented. In an apparent internal inconsistency, it appears Hydro's IFF07-1 utilizes the load forecasts included in the 2007/08 Electric Load Forecast (which assume no New or Expanded Industrial Rate), but for the purposes of forecasting revenues assumes that the proposed New or Expanded Industrial Rate is in place.

Hydro's filing also includes the responses to various Board directives in Appendices 12.1 to 12.13.

[10] Appendix 45

[11] Filed as part of the 2.25% conditional rate increase Application January 28, 2005.

[12] The 2007/08 Power Resource Plan appears to retain the same assumptions as the 2004/05 Power Resource Plan with respect to this major sale. It is not clear whether recent events since the 2007/08 Power Resource Plan was prepared have resulted in extensions or modifications to this sale agreement.

[13] Coalition/MH-I-42(e).

[14] 2006/07 Power Resource Plan, page 2, Appendix 34.

3.0 FINANCIAL RESULTS AND PROPOSED INCREASES TO OVERALL LEVELS OF RATES

Manitoba Hydro's most recent Integrated Financial Forecast filed with the Application materials (IFF07-1) indicates a marked change in financial position from the financial forecasts reviewed by this Board since practical regulation of Hydro's rates resumed in 2001.[15] In particular, the span of information with respect to this recent history of regulation can be focused usefully on the following two IFFs:

- **IFF02-1:** The first IFF to fully incorporate the purchase of Winnipeg Hydro, as well as the "special export payment" to the Province of Manitoba. This IFF was the last version reviewed as part of the overall process leading to confirmation of the rates approved in Board Order 7/03 (the "Status Update hearing").[16] This IFF was also the basis for Hydro's adoption of the current financial target related to achieving a debt:equity ratio of 75:25 by 2011/12.[17]

- **IFF07-1:** The most recent IFF available to the current proceeding is IFF07-1.[18] Unlike IFF02-1, the current IFF no longer shows Hydro able to meet its financial target of 75:25 debt:equity by 2011/12.

Other Financial Forecasts provided during the intervening period (IFF03-1, IFF04-1, IFF05-1, IFF06-4) in certain cases provide useful points of analysis for cost forecasts that have evolved over the period. A comparative analysis of the above two main IFFs is provided in Attachment B to this evidence. In sum, the Attachment reviews the following matters:

- IFF02-1 is the basis for setting the financial target of reaching 75:25 debt:equity ratio by 2011/12. By IFF07-1, this financial target is no longer achieved.

- Although Hydro asserts a number of factors are causing the deterioration in financial results, with the exception of higher capital spending, most of the rationales cited by Hydro are not supported the current evidence or historical events:

  - **Special Export Payment to the Province –** IFF02-1 already included a special export payment to the province, and still managed to achieve 75:25 by 2011/12. In fact the export payment in that IFF was at $254 million, compared to an actual payment of $204 million. As a result, this is not a reason for deterioration of Hydro's debt:equity ratio.

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[15] Hydro become regulated by the PUB with the passage of the Crown Corporations Public Review and Accountability Act in 1989, and was subject to GRA reviews in 1989, 1990, 1991, 1992, 1994 and 1996. No further reviews occurred until the Status Update proceeding (2001-2002).

[16] The Status Update hearing focused on review of IFF01-1, but following Order 7/03, Manitoba Hydro sought to Review and Vary the decision based on the information contained in IFF02-1. With respect to rate levels, this application to Review and Vary was denied in Order 154/03.

[17] Per PUB/MH-I-23(a)

[18] However, note that the Cost of Service study in the current proceeding is based on IFF06-3.

- **2002-2004 Drought** - While the drought of 2002-2004 did seriously hamper Hydro's progress towards its debt:equity targets, by 2006/07 the level of retained earnings has recovered to the levels forecast in IFF02-1, and by 2007/08 the debt:equity ratio is improved compared to IFF02-1. In short, while the effect of the drought was severe, it was entirely neutralized within less than five years.

- **Higher Domestic Loads and Lower Rate Increases** – It is not correct that actual rate increases have been below IFF02-1 levels. Other than 2003/04, actual cumulative domestic rate levels and forecasts in IFF07-1 are above the level forecast in IFF02-1. In addition, outside of the drought year, actual combined revenues (export plus domestic) and IFF07-1 revenues are higher than forecast in IFF02-1. Of note, the analysis indicates that even in a situation where Hydro is not permitted any special Industrial New or Expanded Loads marginal-cost-based rate, corporate revenues in IFF07-1 are higher than in IFF02-1.

- **Higher Capital Spending** – Upon review, this is the only factor cited by Hydro that genuinely contributes to the deterioration in financial position. While this is indeed one reason that Hydro's debt:equity targets are no longer being achieved, the effect relates mostly to major new generation and transmission, including Wuskwatim. Given that these new generation projects are being pursued on the basis that they will not drive higher rates for domestic customers and indeed will benefit domestic customers over the long-term, the use of this factor as an implicit justification for rate increases at the present time is a matter that should be of concern to the Board.[19]

- The significant increase in Operating, Maintenance and Administration ("OM&A") costs is one factor that Hydro did not cite as contributing to the deterioration in financial targets. As noted in Attachment B, the deterioration totals over $300 million for the period from 2002/03 to 2012/13. This factor alone represents an adverse impact approximating a range of 2-3 percentage points on the debt ratio. All other things being equal, had Hydro maintained OM&A spending at the levels forecast in IFF02-1, the financial targets to 2011/12 would have basically been achieved, notwithstanding the drought and other factors noted above.

Outside of pure analytical results, the comparison of the two IFFs reflects a critical juncture in respect of regulating Manitoba Hydro. For example, while Hydro's financial performance in terms of net income and retained earnings is ahead of all earlier expectations, the financial measures cited by Hydro suggest that Hydro's financial condition has deteriorated from what was intended in the earlier forecasts. Similarly, although sustained domestic rates today and total revenues are higher than past assumed requirements, Hydro now indicates larger rate increases than previously expected are required for the foreseeable

[19] Although Hydro has not indicated it is seeking rate increases to address the costs of bringing Wuskwatim on-line, the net effect of retaining a target of 75:25 under *both* the situation with a Wuskwatim in-service (IFF07-1) and a situation without a Wuskwatim in-service (IFF02-1) is to seek to fund material components of the cost of Wuskwatim with equity. As the Wuskwatim project is not forecast to generate any equity over this period of time (expected to suffer small losses in the first six years), this equity is in effect being sought from domestic ratepayers.

future, above the level of forecast inflation. The entire forecast situation diverges even farther from any past experience with Hydro when viewed in the context of what is only slightly beyond the horizon portrayed – a potential for nearly $10 billion in additional projects coming into service within approximately three years beyond the current IFF period.

The balance of this section reviews two major areas related to Hydro's Revenue Requirement. First, an overview of the current structure of regulation that applies to Hydro is presented. Second, specific comments are provided in respect of Hydro's revenue requirement and the overall level of rates.

3.1 APPROACH TO REGULATION UNDER THE CURRENT MANITOBA FRAMEWORK

In the recent regulatory reviews of Hydro, there has been consistent recognition of the need for appropriate "reserves"[20] to address the risks (most notably drought) faced by Hydro and its ratepayers. Although regulation of Hydro prior to 1998 focused on the need to achieve a quantified level of reserves based on specific quantified calculations, in the more recent reviews (since 2001), practical application of this principle has focused on the long-term achievement of a debt:equity target for Hydro. The materials filed by Hydro in this GRA underline the need to recognize the inadequacy of continuing such an approach in the coming years, in two regards:

- **Overall levels of debt**: In the coming years (including years slightly beyond the current IFF forecast), Hydro is forecast to amass debt on a scale that is nearly unimaginable in the context of any experience with this utility. As the numerator in the debt:equity ratio, this value stands to overwhelm any efforts to achieve target debt:equity ratios in the range discussed today. Future debt:equity ratios for this utility will be massively skewed by major projects, and any efforts to re-establish ratios in the range noted by Hydro would require major rate increases to domestic customers arising due to advancement of export-driven projects, which is opposite the clear policy intention for pursuit of these projects.[21]

- **Sufficiency of Equity:** The current use of retained earnings as the equivalent of reserves serves to significantly neuter the Board's ability to directly influence the key measure of concern. Retained earnings can only be built to the extent that the following two conditions arise concurrently: revenues are maintained or enhanced, *and* costs for operating and capital related expenditures are limited. Under the current framework the Board only maintains direct controls over revenues (via rates).

Each of these matters is addressed below.

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[20] For example, section 14.3 from Board Order 143/04.

[21] Per the Wuskwatim CEC filing, Need for and Alternatives to the Wuskwatim Project, Volume 1, page 6 of the Overview: "Temporary increases to the Corporation's debt/equity ratio and decreases to the level of interests coverage which may occur in the early years of the project are judged to be manageable without impacting the Corporation's financial stability or requiring any offsetting increases to domestic rates. In the medium to long-term, once the project's profits have sufficiently improved the debt/equity ratio, retail customers will realize substantial rate benefits". In addition, the Clean Environment Commission report at page 16 noted: "The Commission's support for the Projects is contingent on MH being able to maintain its commitment that domestic ratepayers will not experience rate increases as a result of the Projects."

3.1.1 Issues Related to the Debt:Equity Target in the Current Expansionary Environment

Hydro's most recent IFF forecasts indicate that it will not achieve its debt to equity ratio target of 75:25 by 2011/12 or even within the forecast period through 2017/18. Notwithstanding this inability to achieve the targeted levels, Hydro's Board has not elected to adjust the targets to a more meaningful level. By the end of 2017/18, Hydro's retained earnings are forecast to have grown from today's level of about $1.7 billion to $2.7 billion, but will remain below the 75:25 target by approximately $0.3 billion.[22]

When the potential for $5 billion to $10 billion of additional capital projects in the three years following the current IFF horizon is included[23], it is apparent that a 75:25 debt:equity ratio could only be achieved with unprecedented added net income on top of that already forecast in IFF07-1. In terms of the resulting retained earnings level, this target equates to requirements for in excess of $1 billion to more than $2.5 billion[24] (i.e., retained earnings levels in the $4 billion to as high as $6 billion level). It is an understatement to say this is not possible within the commonly understood financial framework for Manitoba Hydro.

As an initial step within this GRA review, it is necessary to view Manitoba Hydro's debt to equity target in light of its capital plans. Hydro's debt:equity target of 75:25 by 2011/12 was set by the Manitoba Hydro Board of Directors based on IFF02-1 which did not assume any new Major Generation projects would be in service in the forecast period[25] and contemplated successful achievement of this target with less than $2 billion in retained earnings.[26] Although it sounds mathematically equivalent to target the same ratio (75:25) within the next 10-15 years, the practical effect is that the target has been significantly raised – to the point of being doubled or even tripled – from what was before the Board when this target was first seriously debated.[27]

It is very difficult to conceive of Hydro reaching upwards of $6 billion in retained earnings using the current frameworks in place, within any timeframe less than a number of decades. As a result, it is apparent that the metric of debt:equity has little enduring meaning in providing a useful guide to the PUB and ratepayer decisions regarding the level of domestic rates in any given year.

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[22] IFF07-1 indicates a sum total net income over the period for Electric Operations of $1.879 billion. PUB/MH-II-25(f)(i) indicates the level of net income required to get to 75:25 by 2017/18, totaling $2.196 billion for Electric Operations over the same period, a difference of $317 million.

[23] Rough figures discussed in materials put Keeyask at $4 billion per PUB/MH-I-4(d) and Conawapa at approximately $5 billion per IFF07-1 page 33. It is not apparent that these figures include all related local transmission requirements.

[24] The potential for approximately $10 billion in added major projects by the end of 2020/21 ignores added growth in non-major projects, which would similarly drive some level of need for new equity. Further, Hydro's electricity operations capital forecast for the years 2007/08 through 2016/17 is over $0.900 billion higher in Capital Expenditure Forecast (CEF) CEF07-1 compared to CEF06-1 – no provision is made in these numbers for potential similar escalation in potential future CEF documents.

[25] IFF02-1 assumed a simple new HVDC line would be in service by 2010/11, at a cost of $352 million, or about 15% of the current Bipole 3 concept of $2.248 billion.

[26] By the end of 2011/12 in IFF02-1, the electric operations retained earnings totaled $1.931 billion.

[27] As of the 1996 GRA, the primary target before the PUB was to reach a debt:equity ratio of 85:15 by 2001/02 per the Executive Summary from Order 51/96.

3.1.2 Issues Related to Targets Measured using Retained Earnings, or "Equity"

The analysis in Attachment B gives rise to significant concerns with respect to the regulation of Manitoba Hydro over the past five years and the lack of sufficient linkages between the Board's jurisdiction (limited to rates) and the broad number of factors that affect retained earnings.

At its most basic level, the Board has noted that it desires to ensure ratepayers are sufficiently protected from future risks such as drought via reserves, which is an appropriate regulatory objective. At the present time, these reserves are only conceived of by Hydro as being equivalent to "retained earnings".[28] As retained earnings are largely the sum total of past net income, in any given year Hydro's retained earnings only grow to the extent overall revenues exceed overall costs[29].

Against this backdrop, it is necessary to consider the tools available to the Board to give effect to its concerns over the level of reserves. The key direct control available to the Board is via Hydro's domestic revenues. Using this tool, the Board can only affect Hydro's "top line" General Consumers Revenue. However, evidence indicates that with respect to Hydro's costs, both for OM&A spending, and particularly for normal capital spending, the Board appears to have had little influence on encouraging and giving effect to cost control. So long as this situation remains, intervenors and the Board are left with the sole decision as to how much domestic revenue to provide to Hydro in the apparently vain hopes that sufficient quantities of this revenue will be available, at the end of the day after Hydro incurs its preferred level of operating and capital related costs, to bring the bottom line up to expectations and build reserves as intended. To deal with each topic in turn:

- **OM&A Costs:** At the time of the 2001 Status Update proceeding, the review of Hydro's performance since the 1996 GRA indicated an excellent performance with respect to operating cost control. In particular, comparing IFF95-2 to IFF01-1 showed that actual OM&A costs over the five years from 1996/1997 to 2000/2001 in each year were below the IFF 95-2 forecast. In that proceeding, the evidence of J. Osler and P. Bowman on behalf of MIPUG noted "Two things are suggested from the above comparison: one is that Hydro has been diligent in operating cost control through most of the period under review, and the second is that there have not been any increases in operating costs (compared to forecasts) to parallel the increases in revenues".[30]

  The situation over the last five years does not parallel the earlier experience. As noted in Attachment B, since 2001/02, Hydro's operating cost forecasts have consistently been raised in each subsequent IFF and despite this escalation have routinely exceeded forecasts.[31] Failure to maintain operating costs within the long-term forecasts has been a consistent and compounding reason underlying Hydro's failure to make progress towards the desired target

[28] Numerous examples exist where Hydro rejects any other concept of reserve, including: See, for example, Appendix 42; also Coalition/MH – I-106 and Coalition/MH-II-93.

[29] Also, assumes Hydro continues to be prevented from paying dividends.

[30] See page 16, Pre-Filed Testimony of J. Osler and P. Bowman In Regard to Manitoba Hydro Status Update Rate Review, April 5, 2002.

[31] See Figure B.4-1 in Attachment B.

debt:equity ratio over the past number of years. In Order 7/03, the Board recognized concern over the potential impacts of operating costs if they were not maintained under control by noting at that time: “Although Hydro’s operating and administration expenses appear reasonable, the Board encourages Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force.[32]”

- **Normal Capital Spending:** Unlike operating expenses, Hydro’s sustained record with respect to controlling the level of “normal” capital expenditures during the period from the 1996 GRA to the 2001 Status Update was poor. In this regard, the concept of normal capital spending is consistent with the definition set out in IFF02-1: “All capital construction requirements excluding new major generation and/or major transmission facilities...[33]” The Board expressed strong concerns with respect to Hydro’s capital spending controls going back as far as Order 51/96 (1996 GRA) where the Board recommended that Hydro “...stringently limit its capital expenditures where safety and reliability constraints allow and apply itself to reducing long-term debt with urgency”.[34] By Order 7/03 (Status Update) the Board noted that “The Board remains concerned with the progressive growth in capital expenditures from $250 million in 1996 to $425 million in 2002. The Board reiterates its concerns expressed in Order 51/96”.[35]

  During the 2004 GRA, there was discussion about capital spending and its associated impacts on Hydro’s debt. In particular, at that time Hydro was actively engaged in seeking approvals for the proposed Wuskwatim project and noted that absolute reduction in debt while undertaking major new revenue-generating bulk power projects was neither possible nor desirable. As noted by Hydro:

  > ...anytime we're expanding as we are with -- expect to be with Wuskwatim then, of course, reducing debt is -- is not possible, nor is it desirable because debt is good; that's where we get our source of funds. So borrowing for purposes of growth, as I indicated earlier, is a good thing to do. It's good for Manitoba Hydro; good for its ratepayers. So reducing debt is -- is contrary to the whole concept of growth and in itself is not – is not a good objective for Manitoba Hydro.[36]

[32] Order 7/03 at page 92.
[33] IFF02-1 at page 28.
[34] See Order 7/03 at page 90.
[35] Ibid.
[36] Transcript June 14, 2004, pages 203-204.

Hydro's summary provides a fair commentary on the need for debt financing to bring on new major revenue-generating capital projects; however, this same summary does not apply on a sustained basis to normal capital spending for replacements or general annual system improvements. The Board echoed this concern in Order 143/04 when it noted:

> The Board continues to be concerned with the progressive substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Gull, Conawapa, and may be justified individually when considering each project's purposes and forecast results over the long term.
>
> However, collectively these projects negatively impact MH's debt to equity ratio and net income in the initial years, placing increased strain on the financial stability of MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the company.[37]

The evidence in this proceeding demonstrates that Hydro's normal capital program has not yielded despite the Board's strong directives in Order 7/03 and 143/04:

– The **CEF07-1** capital expenditures total $11.610 billion over 11 years. Approximately $7.484 billion of this amount is for major new generation, transmission and DSM. The residual $4.126 billion yields an average capital spending on "normal" items of $375 million per year.

– In **CEF02-1** the total 11 year expenditures were $4.384 billion, but this includes a number of projects or concepts that are now considered (per CEF07-1) to be major new generation, transmission and DSM[38], which total $1.250 billion. The resulting normal capital spending under the current definitions is $3.134 billion or about $285 million per year average over the 11 years.

This comparison reflects an increase of over 30%, or an average annual growth rate for normal capital spending of nearly 6% between CEF02-1 and CEF07-1, approximately half of which may reasonably be cited as being consistent with CPI typical inflation over the period. Given clear capital project cost

[37] Board Order 143/04 page 95.

[38] This includes $0.640 billion identified as new major projects in CEF02-1, plus $152 million for DSM, $6 million for Kettle GS Improvements and Upgrades, $75 million for Kelsey GS Improvements and Upgrades, $273 million for Pointe du Bois GS Improvements and Upgrades, $57 million for Planning and Study Costs, and $47 million for Herblet Lake to The Pas 230 kV Transmission.

escalation occurring at the present time, it is possible that 6% sustained annual growth may be justifiable as a premium "construction project" inflation over the period, but it is clear that Hydro has not reflected any notable downward cost control measures consistent with the Board's directives.

As an additional cross-check, Attachment B (citing PUB/MH-I-7(b)) demonstrates that over the same 11 year period 2002/03 to 2012/13, CEF07-1 actuals exceed CEF02-1 forecasts for normal capital spending by 40 per cent.

Given the above two items in Hydro's overall cost structure, a simple continued pursuit of higher domestic rate levels cannot provide any real assurance of actual improvements in retained earnings to the Board and intervenors. As long as retained earnings remain the only concept considered for developing ratepayer protection from drought, there is a basis for concern that the Board can do little to fully ensure its desire for an adequate level of reserves is fulfilled.

3.1.3 Direction for Evolution of the Approach to Regulating Manitoba Hydro

Against the backdrop of issues noted above, it is necessary to consider how the Board and intervenors can suitably ensure that their objectives of rate stability and sufficient "restricted" drought reserves can be met. This evidence addresses three major aspects of evolution of the Manitoba form of regulation for Hydro that the Board should adopt or recommend. At a basic level, none of this discussion is new to the Board:

- **Debt:Equity as Insufficient Measure for Determining Level of Needed Rate Changes:** The need to move beyond a simple debt:equity measurement in setting regulatory reserve provisions is consistent with measures identified by the Board in Order 7/03, in particular, setting such reserve provisions based on "a process that identifies and quantifies at least the major risks at a high level" [39]. The Board concluded in that Order, that the measure of reserve levels would be "arbitrary" if they were not quantified based on risks. Measuring reserve levels solely by reference to total capital, as the debt:equity target implicitly does, fails to link the reserve levels with any quantified risk assessment.

- **General Retained Earnings Poorly Fulfill Role as Reserves:** In Order 7/03, the Board determined that a reserve amount should be quantified, and sought development of "a policy to identify a reserve provision amount and in particular, to set the circumstances under which it can be drawn down or increased, keeping in mind the statutory limitations in *The Manitoba Hydro Act*.[40]" The concept as noted by the Board cannot be reasonably interpreted to equate reserve provisions with general unrestrained retained earnings, given there is no need to set circumstances or policy as to how retained earnings can be used or drawn down – retained earnings are solely a mathematical outcome of a series of net income levels. The Board noted in Order 143/04 that it sought information from Hydro on the potential to internally restrict its retained earnings[41] and while Order 117/06 rejected a recommendation by MIPUG "to require MH

[39] Order 7/03, Section 21.4 at page 89.
[40] Ibid.
[41] Board Order 143/03, page 94.

to restrict retained earnings to serve as a specific drought reserve" that conclusion was based on the assumption that such ratepayer reserves would be in addition to Hydro's financial targets, as noted by the Board: "To hold the 75:25 target and set aside a further provision for drought would be to double-count, and is not necessary".[42]

Evidence provided in past proceedings before the Board has identified that many hydro-based utilities that are exposed to risks of drought have internal means to address water flow variations and with regulator approval, other risks. Fully regulated examples exist in Yukon (the Diesel Contingency Fund), Northwest Territories (NWT Power's Water Stabilization Fund) and Newfoundland (the Rate Stabilization Plan). In addition, the same effect arises under the new legislation in Quebec, whereby the unregulated Hydro Quebec Production division is required by law to sell up to 165 TWh to the regulated Distribution division at a fixed price of 2.79 cents/kW.h, regardless of water flows[43] – to the regulated customer this equates to a fully stabilized rate regime for bulk power.[44]

- **Revisit Past PUB Recommendations with respect to Revisions to the Legislation:** The Board's current jurisdiction over the rates Manitoba Hydro charges, without corresponding controls more typical of regulated jurisdictions (and as are found in the Manitoba *Public Utilities Board Act*) gives rise to many of the issues noted above. As far back as 1999 (Board Order 146/99), the Board provided recommendations to the Government of Manitoba that "The *Public Utilities Board Act* be amended to remove Hydro's exemption under Section 2(5)."[45] This same concept was repeated in Board Order 143/04 where the Board noted: "Given the risks related to the very significant additional plant investments and associated borrowings contemplated, the Board is of the view that the Province of Manitoba should re-evaluate the existing legislation".[46]

Each of the above three matters merits serious consideration by the Board. As part of the present proceeding, consideration should be given to the need for a focused debate (similar to the recent Cost of Service hearing) on issues and options regarding establishing secure regulated reserves. In this regard, consideration should extend to the determination of the appropriate levels of these reserves, alternatives for maintaining the reserves fully under the Board's jurisdiction and oversight and measures for calculating, in any given year, the necessary level of appropriation to, or withdrawal from, the reserve account(s).

[42] Board Order 117/06, page 69.

[43] http://www.hydroquebec.com/publications/en/strategic_plan/2002-2006/pdf/strat_69_80.pdf at page 76.

[44] Hydro has cited that BC Hydro terminated its Rate Stabilization Account in 2004 (per Appendix 42), which is not a relevant comparison. In the case of BC Hydro, the utility is regulated on a "Return on Equity" basis, and the Rate Stabilization Account being referenced was a government-ordered account that operated as an after-the-fact adjustment to net income; as such it did not serve to stabilize rates on a prospective basis, but instead, effectively, served to stabilize the dividend to be paid to the BC Government out of Hydro's return on equity pursuant to the legislation in BC.

[45] Order 146/99 ate page 86.

[46] Order 143/04 at page 96.

3.2 SPECIFIC COMMENTS ON THE REQUESTED REVENUE REQUIREMENT

It is difficult to assess the "need" for Hydro's requested overall 2.9% rate adjustment at this time. This is because the tools applied in recent regulatory experience in Manitoba (such as the debt:equity targets) are of diminished value. In addition, it is not apparent in the materials filed by Hydro that the series of 2.9% increases forecast for each year until 2017/18 are not, in effect, being driven by Wuskwatim[47], contrary to the policy directives on this project.

Hydro's own record with respect to determining the required or desired level of rates underlines the present climate of uncertainty. In particular, the following points are noted:

- **Increases approved for 2004, plus two conditional increases for 2005:** Order 101/04 provided for Manitoba Hydro to receive a 5% increase to all classes effective August 1, 2004, followed by two conditional increases of 2.25% each to all customer classes on April 1, 2005 and October 1, 2005.

- **First conditional increase for 2005 sought and approved:** Hydro sought and received approval for the April 1, 2005 2.25% increase in Order 34/05.

- **Second conditional increase for 2005 declined by Hydro:** In a letter dated July 5, 2005, Manitoba Hydro stated that due to "a dramatic turnaround in water conditions" since the 2004 GRA it would forego seeking the 2.25% conditional rate increase tentatively approved for implementation on October 1, 2005. It was stated that after the third worst drought on record, which subsequently led to "the largest financial loss on record in 2003/04", water conditions rebounded to the point that net income was projected to exceed $250 million in 2005/06[48].

- **Increase sought for 2006 and 2007:** On November 1, 2005, Manitoba Hydro filed a GRA seeking electricity rate increases of 2.5% to be effective April 1, 2006, and a further increase of 2.5% to be effective April 1, 2007. On November 4, 2005 the PUB advised MH that as set out in Order 143/04, the Board considered the Cost of Service Study and related issues to be significant, and expected COSS issues to be resolved before the next GRA was filed.

- **2006 and 2007 Request for Increase Withdrawn:** Manitoba Hydro filed an application in November 2005 for a revised COSS. At a pre-hearing conference for the Cost of Service Hearing held on November 24, 2005, Manitoba Hydro withdrew its planned GRA stating that it was projecting a net income in the range of $350 million for the 2005/06 fiscal year - "an all time record for the corporation" (Manitoba Hydro's previous net income record being set in 2000/01 when a profit of $270 million was achieved).[49]

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[47] In particular, note that by 2011/12, Wuskwatim will have contributed to a reduction in retained earnings of $26 million, while driving an increase in total debt to fund essentially the entire project (approaching $1.2 billion per MIPUG/MH-I-10(a)).

[48] Letter dated July 5, 2005 from R.B. Brennan addressed to Mr. Graham Lane.

[49] COSS hearing transcript, November 24, 2005, at page 18-21.

- **2007 Reinstatement of Previously Declined Rate Increase from 2005:** On January 26, 2007, Hydro applied to the Board to reinitiate the conditionally approved 2.25% rate increase from 2005 that had earlier been declined by Hydro due to its then forecast net income, at $102 million, being "well below the level needed to make continued progress towards our financial targets". This increase was approved for March 1, 2007 in Board Order 20/07.[50]

In total, the rate impact from 2004/05 to 2006/2007 exceeds 9.5%.

Appropriate methods of utility regulation would focus on establishing a predictable and measured rate adjustment regime. This situation does not exist today with respect to Manitoba Hydro.

During this period of flux with respect to determining the appropriate long-term rate levels, primary importance must be placed on ensuring that rate decisions have a reasonable means of achieving the regime noted above – that is, predictable and measured adjustments where necessary. Overall increases in the range of 1-3% at this time would not appear to be inconsistent with this broad objective, pending resolution of the regulatory inadequacies as noted above, and assuming confirmation is available to the Board that this level for increase is not being driven or necessitated by the Wuskwatim Generating Station.

With respect to specific items in Hydro's costs or accounting, the following sections review items noted from a review of Hydro's filing.

[50] See letter dated January 26, 2007 from R. B. Brennan addressed to Mr. Graham Lane.

3.2.1 Export Revenue Allocation

In the 2006 Cost of Service proceeding, MIPUG provided evidence which set out that, once a principled cost allocation method is developed to determine the fully allocated costs of serving export revenues (including costs for resources that are above average cost which are pursued or advanced on the basis of serving exports), any residual export revenues might be prioritized as a "preferred approach"[51] to building appropriate drought reserves (and for repayment of Hydro's debt). This MIPUG approach was provided as an alternative to Manitoba Hydro's proposal to apply all such "surplus" export revenues to offsetting the costs of Hydro's general system assets (generation, transmission and distribution)[52] so as to allow for lower domestic rates in the near-term. Following that same principle, the Board noted in Order 117/06 that:

> The significance of MH's net export revenues to COSS and domestic rates depends in large part on the amount of net export revenues credited back to the domestic classes, rather than being employed in some other way. This topic will be revisited at the next GRA hearing, and may be important to future rate decisions.[53]

An attractive alternative for use of export revenues that are in excess of the fully allocated costs of serving exports (measured by principled COSS approaches) remains the allocation of these amounts toward a regulated reserve fund for future use to stabilize rates in the event of a drought. This approach may simultaneously allow for reducing Hydro's net debt (through repayment or repurchase), such that resources are available to stabilize Hydro's net income, and by consequence rates, in times of low flows. 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.

Hydro has prepared PCOSS08 to comply with the directions of Order 117/06. There is one technical correction related to DSM treatment in PCOSS08 that warrants adjustment, as discussed later in this report (Section 4).[54] However, once that technical detail is addressed, the Board will have a sound analytical framework for identifying the costs incurred to serve exports on a fully allocated basis.[55]
Given the newly confirmed COS study, and in particular the forecast fully-allocated costs of exports (on an embedded basis) of approximately $397 million (average 5.15 cents/kW.h when divided by the

[51] Evidence of P Bowman and A McLaren, March 16, 2006.

[52] There is 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 or must declare a dividend or "distributable surplus" that is paid to the respective province. 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. More importantly, however, Manitoba Hydro's current debt:equity ratio exceeds the level at which provincial legislation in many jurisdictions would prohibit a dividend, and Hydro maintains no special reserves to deal with Rate Stabilization or drought. In this regard, the export revenues collected today are not "surplus" as this term is used in other provinces.

[53] Order 117/06, at page 21.

[54] Results following this adjustment are provided in MIPUG/MH-I-25(b).

[55] While the fully allocated costs of exports provide interesting information about average pricing for the system, parties who review the PCOSS must understand that this pricing provides no useful measure to instruct Hydro in a number of areas, such as: when to build a new plant; how to evaluate the economics of a new plant; when to make an export sale; or how to dispatch the system.

number of units exported, at the meter), there is a potential to clearly identify that portion of export revenue that is not presently required to cover the fully-allocated costs to serve exports on a unit basis. Under the present situation, absent a priority allocation of this "surplus" export revenue (such as to fund the Uniform Rates policy), this amount is allocated back to all customers via the Cost of Service study in proportion to each class' total allocated costs. In short, the surplus export revenues serve to allow ratepayers today to pay less than the fully allocated costs of serving their class.

There remains a compelling case, in the event an appropriate and protected reserve provision mechanism can be developed using any number of approaches (from third-party investment mechanisms, to internal "trust" approaches, to regulatory liabilities), to apply this identified "surplus" export revenue amount as an initial allocation to begin to build such reserves. Section 4 of this evidence identifies the potential ultimate allocation as being approximately $131 million.[56] This surplus can only exist to the extent domestic rates are adjusted to remove this allocation (subsidy) from the rate-setting process. It is important to note that these funds only arise to the extent domestic rates are raised to replace this amount of revenue from the appropriate classes of Manitoba customers – this will take time. The eventual outcome of such a transition, where export revenues in excess of their fully allocated costs are prioritized towards building necessary and prudent protected reserves, will help all ratepayers, as these needed funds will be available as of the next drought to help offset or avoid the need for the same level of rate increases that would otherwise be required.

The Board should ensure that any investigation of the potential for protected reserves as noted in the preceding section includes consideration of the implications for long-term rate levels arising from the evolution of net export revenue allocation (what Hydro referred to in the 2006 Cost of Service hearing as "above cost" export revenues) and in particular a revision to ensure these revenues are first allocated to secure ratepayer reserves under the oversight of the Board rather than to the COS analysis.

A breakdown of the PCOSS08 result of $131 million in "surplus" or "above cost" export revenues can be calculated from MIPUG/MH-I-25(b) and is summarized in Section 4.

3.2.2 Sinking Funds

The Manitoba Hydro Act requires the Corporation to make annual sinking fund payments to the Minister of Finance of not less than 1% of the debt and 4% of the sinking fund balance at March 31st of the previous year[57] except where exempted by the Minister. The Minister invests the sinking fund payments in securities that are authorized by Section 27(2) of *The Financial Administration Act*.[58] Maintaining sinking funds for future debt repayment has been reasonably common longstanding practice among Crown owned utilities, such as Newfoundland and Labrador Hydro, NWT Power and New Brunswick Power.

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[56] Per MIPUG/MH-I-25(b), derived from the difference between a fully allocated cost of exports of $414 million and a forecast export revenue of $552 million. However, $7 million of this amount is required as an allocation to the diesel zone and cannot be addressed by the methods noted above.

[57] MIPUG/MH I-12 a).

[58] The authorized securities are detailed in the response to MIPUG/MH I -12 a).

Though Manitoba Hydro indicates it does not maintain detailed information on the sinking fund policies of other Crown utilities[59], Hydro has confirmed that B.C. Hydro's sinking fund requirements were removed from its obligations on all new and outstanding debt as of December 2005.[60] Hydro also notes that no transition provisions were necessary when the sinking fund requirement for B.C. Hydro was eliminated.[61]

Hydro estimates that removing its own sinking fund requirements would result in a benefit to net income of approximately $93 million during the IFF07-1 period[62] (due to reduced finance expense).[63] While these savings represent the immediately apparent avoided costs that may arise, there would also seem to be a potential for further financial benefits from reducing the exposure to interest rate spreads between the earnings on the sinking funds as compared to the interest costs on the underlying debt, and by allowing a more flexible approach to maintaining bullet payment debt. Hydro has indicated that it does not believe eliminating the sinking fund requirements would have any adverse effect on the borrowing rates it is able to secure[64]; its ability to access capital markets[65]; the range of borrowing instruments available to it[66]; or the debt ratings for Manitoba and related contributions of Manitoba Hydro to the provincial debt rating.[67]

Despite the cost savings that would be available to Hydro, with no apparent adverse effects, Hydro indicates that it has not sought relief from sinking fund requirements to date but that it will be pursued at an "opportune time".[68] Given the magnitude of Hydro's planned capital program and associated debt requirement, as well as Hydro identifying upward pressure on capital project construction costs as a key financial risk[69], it is not clear why this is not an opportune time for such evolution.

While Hydro cannot apparently terminate sinking fund contributions without some form of relief under the necessary sections of *The Manitoba Hydro Act*, such relief should be assessed, based on the support of Hydro and the Board, as a clear measure to aid in reducing costs to ratepayers.

3.2.3 Brandon Unit #5

IFF07-1 canvasses for the first time the financial impacts that may arise in the event the Brandon Unit #5 (coal) is prematurely decommissioned; it is estimated that for each year the plant is prematurely shut down (prior to 2019), there will be an adverse impact on net income of $20 million per year.

Hydro provided numerous responses to Information Requests regarding the appropriate management of Brandon Unit #5 and the need for the plant, in light of the environmental permits and licences in place

[59] MIPUG/MH I -12 c)
[60] MIPUG/MH I – 12 d)
[61] MIPUG/MH II-13 c)
[62] MIPUG/MH II-13 a)
[63] MIPUG/MH II-13 e)
[64] MIPUG/MH II-13 h) i
[65] MIPUG/MH II-13 h) ii
[66] MIPUG/MH II-13 h)iii
[67] MIPUG/MH II-13 h) iv
[68] MIPUG/MH I – 12 g)
[69] Page 18 IFF-07-1

(and continuing to be secured). In particular, Hydro notes that the local environmental impacts from Brandon Unit #5 are well within licensed levels, if not negligible.[70] Further discussion on the necessity of the plant and the economics of any decision to prematurely close the plant for GHG emission reasons are noted in the materials, as follows:

- MIPUG/MH-I-5(b) notes that with an early closure of Brandon Unit #5, Hydro would experience a series of years from 2012/13 to 2014/15 where there is a system firm energy shortfall (i.e., risks of not being able to supply all committed loads in the event of a drought).
- MIPUG/MH-I-5(c) indicates that absent Brandon Unit #5, the costs of a major drought to Hydro would increase by $150 million or more depending on market conditions.
- MIPUG/MH-I-5(g) indicates that prematurely closing the plant is not a cost-effective measure to reduce GHG emissions. In particular, even if capital costs of replacing the plant with other thermal generation is ignored, the operating cost (fuel) per tonne of potential GHG emissions avoided by closing the plant ($138/tonne to $140/tonne) are well in excess of even the highest expected cost of offsets (noted in that response at $15/tonne).

On any dominantly hydraulic system it is necessary and prudent to maintain thermal generation resources to provide necessary backup as well as firm energy. This extends to both Brandon #5 (coal) as well as units #6 and #7 (natural gas simple cycle CT). In this situation, concern is merited over any efforts to impair the system capability through early closure initiatives.

3.2.4 Capitalization and Deferral of Costs

In Board Order 117/06, Hydro was directed to provide information on its accounting practices with respect to capitalization and deferral of various expenses. Hydro's response, noting the current practice, is set out at Appendix 12.6.

Approaches to deferring and amortizing costs in a rate regulated environment appropriately focus on matching the amortization period and amounts of any cost with the underlying benefits secured. In certain cases, where no quantifiable benefits arise from major expenditures, amortization approaches may be adopted so as to aid in achieving rate stability. This type of "smoothing" approach may at times vary from the underlying objectives of GAAP reporting, typically towards more acceptance in a rate regulated environment for deferring and amortizing costs than in a strict accounting environment.

Hydro policies with respect to deferring and amortizing costs in most cases appear to be appropriate for a rate regulated environment. While there are a number of deferred cost items to which the Board made particular reference in Order 117/06, three specific items of note are addressed below:

- **DSM costs:** Manitoba Hydro's DSM costs are deferred and amortized over 15 years as standard practice. In contrast, Hydro notes in PUB/MH-II-14(a) that the practice in Quebec is now 10 years, but was previously five years. In B.C., the practice is to use 10 years unless the period of benefit of the program is shorter, in which case the period of benefits is used as

[70] MIPUG/MH-I-5(e); Appendix 12.4.

the amortization period. At a high level, an overly aggressive DSM amortization schedule may serve as a disincentive to certain otherwise economic DSM, and as such the Board should be cautious about proposals to revise Hydro's current horizon for amortization downwards. It may be appropriate in future, in the event Hydro does not already follow this practice, to consider adopting the B.C. Hydro practice of capping amortization periods to no more than the expected life of each individual program (where this can be readily identified).

- **Accounting for Plant Costs related to Uneconomic Generation:** The Board's Order expressed concern over accounting for assets that are "…uneconomic generation with limited expected remaining life (such as the Brandon and Selkirk generation plants)".[71] Hydro's response in Appendix 12.6 provides a clear overview of the requirement for the plants in question, and in particular refutes the Board Order 117/06 statement that "the Board notes no evident direct net present value with respect to future generation and sales from the plants."[72] Further evidence in support of the requirement for these plants, and their economic value to the system regardless as to the expected hours of operation is provided in the 2007/08 Power Resource Plan (Appendix 45 to the filing) at tables A.1 and A.2. With respect to plants with limited economic life, such as Pointe du Bois, Hydro appears to have appropriately addressed this terminal date through changes in the depreciation rates as noted in PUB/MH-I-48(b) page 2. To the extent any of Hydro's major assets have limited economic lives; this is the appropriate mechanism to address accelerated accounting.

- **Planning Studies:** Hydro's approach to capitalizing and amortizing planning studies is to defer and amortize costs related to uncommitted major generation and transmission on a straight-line basis over 15 years. If there becomes a reasonable basis that the project will proceed, any unamortized amounts are transferred to Construction in Progress for the project. While Hydro cited in PUB/MH-II-14(a) B.C. Hydro's current practice with respect to "Large Hydro Investigation Costs", a review of B.C. Hydro's First Quarter Report – Fiscal 2007[73] indicates these costs solely relate to one potential new plant (Site C) and it does not appear that they are being amortized at the present time. Previous to this series of investigations, B.C. Hydro maintained more generic deferral accounts for "studies, investigation costs, and costs of aboriginal negotiations, litigation and settlements"[74] which were amortized over five-10 years. However, it appears these amounts were written off at March 31, 2006[75] due to the ongoing evolution in the form of regulation and accounting for B.C. Hydro. In the event a change was merited in Manitoba Hydro's approach to accounting for planning and study costs, it is worth considering the potential to have no amortization of these amounts until such time as a defined go/no go decision is made on proceeding with the project. For projects that do not proceed, the overriding principle for determining an

[71] Order 117/06 page 80
[72] Order 117/06 page 70
[73] http://www.bchydro.com/rx_files/info/info48100.pdf at page 18.
[74] http://www.bchydro.com/rx_files/policies/policies26794.pdf at page 12.
[75] http://www.bchydro.com/rx_files/info/info46750.pdf at page 90

amortization period in this case is rate stability[76], which appears to support continuation of Hydro's 15 year horizon.

The Board's Order also asked for support for Hydro's policies in respect of capitalization of overheads. While no formal assessment has been done of the detailed policies in preparation of this submission, the conceptual basis for capitalization of overheads is sound and consistent with typical practice in other rate regulated utilities encountered, such as NWT Power and Yukon Energy.

3.2.5 Continue to Push Cost Control

The recent period of regulation of Hydro has been challenging with respect to cost control. Although operating costs were managed carefully and successfully by Hydro over the period from 1996 to 2001, since that time operating cost escalation, and nearly universal increases to the forecast levels year-over-year, has been a major factor in the deterioration of Hydro's financial progress.

The analysis set out in Attachment B to this submission indicates the broad trend in OM&A costs. Of note is the fact that each subsequent IFF, with the exception of IFF05-1, shows a notable increase over each previous forecast for the entire duration of the IFF. As the sole outlier in this trend, IFF05-1 provides an interesting case study. The operating costs in that IFF are specifically noted to be adjusted downwards to reflect "operating savings that are anticipated to result from the new head office building".[77] The head office building was forecast at that time to be in service for 2008/09, which can readily be seen in Figure B.4-1 (in Attachment B to this submission) as the apparently sole reason IFF05-1 has operating cost forecasts lower than IFF04-1. That same rationale for operating cost reductions apparently is no longer a key element of IFF forecasts.

Notwithstanding that the Board's repeated recent expressions of concern to Hydro over operating cost levels[78] have not apparently led to the necessary impetus to bring these costs under control, it is likely necessary for the Board to remain focused on this area of concern. Regulation, by its very nature, does not permit the regulator to supplant the management of the regulated utility. The Board cannot in practice force or dictate that Hydro be vigilant over the level of its costs. The Board can solely encourage Hydro to demonstrate vigilance in this area, lest it fail to receive rates in future to compensate the utility for costs that the Board may deem as unnecessary or copious.

In future applications, the filing of OM&A Expenses in a format that allows consideration by function (Generation, Transmission, Distribution, Customer Service, and Administration) may prove of assistance to the Board and intervenors in assessing the general trend of expenses as they relate to the ultimate

[76] With respect to pure GAAP, it is possible that no amortization would be concluded to be appropriate; however, applying this approach to Hydro's regulated financial statements would impose large costs due to write-downs in a single year and may serve to undermine long-term rate stability.

[77] IFF05-1, page 12

[78] See for example, Order 101/04 at page 22, "The Board will expect MH to maintain vigilance over its costs, so that the additional revenues contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast." See also, Order 7/03 at page 92: "The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies."

level of rates. This approach will particularly aid in the assessment of OM&A expenses per customer, as such a metric is more suitable to distribution and administrative functions than it is to generation, for example.

4.0 COST OF SERVICE STUDY AND GENERAL CONSUMER RATE DESIGN

Unlike the assessment of Hydro's revenue requirement, which is noted above to be in a state of disorder at the present time, Manitoba Hydro's Cost of Service Study has recently been renewed. The comprehensive 2006 proceeding[79] to review Hydro's cost of service method, leading to Board Order 117/06, provides the opportunity for clarity and reliable results with respect to the costs to serve each customer class on Hydro's system.

The current review is the first opportunity to confirm whether Hydro has appropriately and fully implemented the Board's directives in Order 117/06. Outside of that confirmation process and perhaps modest incremental improvements that might be pursued, useful and compelling results can be relied upon from the PCOSS process in this proceeding. At a high level, the COS results indicate the following key points:

- **DSM:** Hydro has incorrectly implemented the Board's directive in respect of DSM, as discussed in detail in the following sections. The net effect of Hydro's approach is to double count the energy associated with DSM (credit this energy effectively to both the domestic customer class where the savings arose, as well as to exports), such that the cost of service study is not balanced. MIPUG/MH-I-25(b) provides a balanced version of the cost of service study results. While the net impacts of the correction are relatively small (less than 2% in RCC for each class, typically less than 1%), there are material changes to certain analytical steps in the PCOSS, and as such the error requires correction.

- **Class Results:** After correction for the DSM double counting, the COS analysis allows for very useful observations into the costs to serve various classes. A few selected examples are set out in Table 4.1. The results with respect to the residential customer class are provided below:

  - Costs – These customers drive average costs for bulk power of 3.78 cents/kW.h (for every kW.h consumed at the meter). However, the Board's directive with respect to DSM cost allocation to exports reduces these costs by 0.06 cents/kW.h, for a net 3.72 cents/kW.h for bulk power. To this, 0.59 cents/kW.h must be added for subtransmission and 3.49 cents/kW.h for distribution. The total cost to serve residential customers is therefore 7.80 cents/kW.h (at row 6 of Table 4.1).
  - Revenues - As to revenues, the average revenue from residential customers is 6.35 cents/kW.h, but the Board's directive with respect to Uniform Rates results in an additional credit to revenues of 0.23 cents/kW.h, for a total 6.59 cents/kW.h (row 10 of Table 4.1).
  - Net Result before Export Credits – Overall, residential ratepayers fail to pay their full costs by 1.21 cents/kW.h. In the event "surplus" export revenues were not credited back to customers in the cost of service study, as was discussed by a number of parties in the

[79] The proceeding covered 11 days of hearings, and cost in excess of $1.25 million per MIPUG/MH-II-3(g), excluding MIPUG's costs which are paid for by the intervenor themselves.

2006 hearing, this is the amount rates would need to be adjusted to fully recover the remaining costs.

- Export Credit - Per PCOSS practice, all as yet unallocated export revenues (approximately $137 million) are credited against the total allocated costs of all functions. The residential class credit approximates 0.89 cents/kW.h (row 12 of Table 4.1).
- Resulting Surplus/Shortfall – For this class, the resulting shortfall in rates is 0.32 cents/kW.h (row 12 of Table 4.1).

A similar analysis was prepared for certain other classes shown in Table 4.1 (and can be completed likewise for any class in PCOSS08).[80]

[80] 1. Total costs (line 6) are taken from the first column of MIPUG/MH I -25 b with the exception of exports, where total costs are reduced by $17.2 million reflecting the uniform rates adjustment.

2. Bulk power, subtransmission, distribution and customer related costs are shown after the creation of an export class, but before net export revenue allocation.

3. Bulk power costs are estimated by adding back the DSM savings of 1,350 GW.h to the export class in column 13 of Schedule D2 of PCOSS08 and reallocating the classified costs in Schedule E1.

4. Subtransmission, distribution and customer related costs are taken from MIPUG/MH I – 25 b) with the net export revenue credits netted out.

5. DSM cost adjustments taken from MIPUG/MH I – 11.

6. Total Sales revenue from column 6 of Schedule C13 of PCOSS08 except for export revenues which are taken from Coalition/MH I – 60 (a) as the sum of dependable and short term opportunity revenues.

Uniform Rates Adjustment taken from column 7 of Schedule C13 of PCOSS08.

7. $61.20 million is the remainder of total export revenue ($551.51 million from Schedule B1). This is assumed to be merchant sales, which seems reasonable as from Coalition/MH I – 33 (a) the average for 2005/06 and 2006/07 is approximately $60.5 million. Net Export Revenue Allocation from column 4 of MIPUG/MH I – 25 b page 2 of 4.

8. Total class metered energy from column 9 of MIPUG/MH I – 25 b, page 3 of 4 except export sales taken from MIPUG/MH II-3 (e).

Table 4.1
Levelized RCC Ratios per kW.h PCOSS08 with DSM Correction

	Residential		GSS-ND		GSM		GSL>100kV		Exports	
	($ M)	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)
Costs										
1 Bulk Power Costs	*$248.8*	3.78	*$54.8*	4.12	*$113.2*	3.84	*$171.1*	3.29	*$372.2*	4.83
2 DSM adjustments	*($4.2)*	(0.06)	*($3.2)*	(0.24)	*($4.2)*	(0.14)	*($6.6)*	(0.13)	*$24.6*	0.32
3 Net Bulk Power Costs	*$244.6*	3.72	*$51.6*	3.88	*$109.0*	3.70	*$164.5*	3.16	*$396.8*	5.15
4 plus: Subtransmission-related	*$38.5*	0.59	*$6.8*	0.51	*$11.7*	0.40	*$0.0*	0.00	*$0.0*	0.00
5 plus: Distrib. and Cust. Serv.	*$229.7*	3.49	*$42.1*	3.16	*$39.7*	1.35	*$2.0*	0.04	*$0.0*	0.00
6 **Total Costs**	***$512.9***	**7.80**	***$100.4***	**7.56**	***$160.5***	**5.44**	***$166.4***	**3.20**	***$396.8***	**5.15**
Rates										
7 Total Sales Revenue	*$417.8*	6.35	*$91.7*	6.90	*$144.2*	4.89	*$164.0*	3.15	*$490.3*	6.36
8 Uniform Rate Credit	*$15.4*	0.23	*$1.2*	0.09	*$0.0*	0.00	*$0.0*	0.00	*($17.2)*	
9 System Merchant Sales									*$61.2*	
10 **Total PCOSS Revenue** (7 + 8 + 9)	***$433.1***	**6.59**	***$92.9***	**6.99**	***$144.2***	**4.89**	***$164.0***	**3.15**	***$534.3***	**6.93**
Surplus/Shortfall before Net Export Credits										
11 **Rates compared to costs** (10 - 6)	***($79.8)***	**(1.21)**	***($7.5)***	**(0.57)**	***($16.3)***	**(0.55)**	***($2.4)***	**(0.05)**	***$137.5***	**1.78**
Net Export Credits										
12 Net Export Revenues Allocation	*$58.6*	0.89	*$11.5*	0.86	*$18.3*	0.62	*$19.7*	0.38	*($137.5)*	(1.78)
13 **Surplus/(Shortfall) after net export revenue credits** (11 + 12)	***($21.1)***	**(0.32)**	***$3.9***	**0.30**	***$2.0***	**0.07**	***$17.3***	**0.33**		
Total Class Metered Energy (GW.h)	*6,578*		*1,329*		*2,949*		*5,202*		*7,707*	

4.1 ASSESSMENT OF OUTPUT OF PCOSS08

Table 4.1 provides the key output of PCOSS08 for a sample of customer classes. The results summarized in Table 4.1 fit with reasonable expectations from the Cost of Service study and include the following:

- **Domestic Bulk Power:** Residential and GS Small bulk power costs are modestly higher than large users such as GS Large due to added line losses between the bulk power system and the meter. This result is expected and is consistent with typical COS results. The GS Small Non-Demand results reflect a somewhat higher cost for bulk power, which may be due to the load profile of the customer (i.e., they may tend to peak at more expensive times than, for example, residential customers who are served at a similar voltage).

- **Export Bulk Power:** Export bulk power costs are higher than domestic classes, as they are served from some of the more expensive resources on the system (such as thermal fuel). The current PCOSS08 approach may understate the true embedded costs to serve exports, as certain potentially higher-than-average cost resources may be pursued by Hydro based on the ability to secure large revenues in the export market; however, in this analysis these resources are simply added into the common "pool" of generation assets. In this vein, there may be merit in considering items such as System Supply Enhancements pursued for economic reasons[81] with a similar treatment to DSM – that is, to have them fully funded by exports to reflect the economic driver of the activity.

- **DSM Costs:** The direct allocation of DSM costs against exports appears to serve a desirable function, that is, to ensure domestic ratepayers are not financially prejudiced by pursuit of DSM programs where the economics of these programs become increasingly challenging (i.e., as the availability of the most economic DSM projects decreases).[82] As the costs of DSM are allocated against exports, this approach means that any such programs will not result in the specific participating customer class being loaded with long-term costs of the DSM programming.

- **Subtransmission and Distribution:** The costs of subtransmission and distribution functions are properly allocated against the classes that use these systems. For smaller users, like the GS Small class, these costs comprise over half of the costs to serve class

[81] Many projects the utility undertakes to renew capital works will serve to enhance the output of the system, due to modern technologies, etc. By economic SSEs, this concept refers only to those projects that are solely undertaken for economic/enhanced output reasons. This can include, for example, re-runnering a plant that otherwise is fully operational because the added output from modern runners more than compensates for the project cost.

[82] It is not appropriate within a regulated rate system to pursue DSM projects that do not pass normal economic tests, such as RIM. Marginally economic projects at times can be hard to justify due to the higher risk that the project savings, compared to project costs, may be insufficient to ensure other "non-participating" customer do not see upwards pressure on their rates due to the project. Under the Board's approved DSM cost allocation approach, this risk is muted, as the individual customer class does not remain responsible for all costs associated with the DSM program in question.

loads. For larger customers, such as Industrial (GSL >100 kV) and Exports, these costs are negligible.

– **Revenues Compared to Fully Allocated Costs:** None of the sample classes reviewed in Table 4.1 are paying the fully allocated unit costs to serve them prior to export credits. It is noted in MIPUG/MH-I-25(b) that of the full complement of customer classes, only one customer class is above 100% RCC before any allocation of net export credits – the Area and Roadway Lighting class (at 101.7%).[83] As a result of the renewed Cost of Service study, this result can now be relied upon to support Hydro's request to have this class receive a lower than average rate increase. Other classes have rates that are below the fully allocated levels to various degrees – ranging from approximately $2.5 million for each of GSL 30-100kV and GSL >100kV, to as high as $18 million for GSL 0-30 kV and $80 million for Residential (shown at line 11 of Table 4.1) and summarized for all classes in Table 4.2 below.[84]

[83] Page 2 of MIPUG/MH-I-25(b), third column.

[84] All data from MIPUG/MH-I-25(b). The third column is the difference between Total revenues less fully allocated costs.

Table 4.2
PCOSS08 Results with Corrected DSM Treatment ($000s)

	Fully Allocated Costs	Total Revenues (after Uniform Rates credit)	Surplus/ (Shortfall) before Export Credits	RCC before Export Credits
Residential	$512,891	$433,136	($79,755)	84.4%
GSS - ND	$100,422	$92,895	($7,527)	92.5%
GSS - D	$116,776	$112,162	($4,614)	96.0%
GSM	$160,478	$144,186	($16,292)	89.8%
GSL 0-30kV	$83,536	$65,925	($17,611)	78.9%
GSL 30-100kV	$38,012	$35,367	($2,645)	93.0%
GSL >100kV	$166,443	$164,004	($2,438)	98.5%
Lighting	$18,919	$19,243	$324	101.7%
SEP	$1,752	$1,561	($191)	89.1%
Total General Comsumers	$1,199,229	$1,068,480	($130,749)	89.1%
Diesel	$11,495	$4,765	($6,730)	41.5%
Total Domestic	$1,210,724	$1,073,245	($137,479)	88.6%

Table 4.2 indicates clearly the impact of reallocation of export revenues (including system merchant sales) which exceed the allocated costs to serve these loads. The total export revenue available for "credit" to the other ratepayers in PCOSS08 (what Hydro referred to in the 2006 Cost of Service hearing as "above cost revenue") is $137 million. Although this amount (less $7 million for a required allocation to the diesel zone) is currently used to maintain domestic rates lower than they would otherwise be, alternately it could be a potential source of funds, over time, for developing an appropriate regulated reserve provision as discussed in Section 3 of this evidence on Hydro's Revenue Requirement.

4.2 ERROR IN IMPLEMENTING 117/06 WITH RESPECT TO DSM COSTS

In Order 117/06, the Board's directive (d) reads as follows: "In addition to the Uniform Rate adjustment, Net Export Revenue is to be further reduced by DSM costs and by the allocation required by Bill 11[85], prior to allocation to the domestic customer classes." This recommendation from the Board followed the arguments of RCM/TREE in the Cost of Service hearing where Dr. Miller noted in respect of the allocation of export revenues (or "fund"):

> Third, funding DSM programs is a natural application of this fund, since doing so not only reduces electric bills in Manitoba, and creates jobs for conservation installation companies in Manitoba; it also increases the revenue from export sales, which to some extent is self-financing if the fund is invested in DSM.[86]

Manitoba Hydro states in PCOSS08 that it has interpreted this directive to mean:

> ....that all DSM energy savings should be assumed to serve the export market. Accordingly, the $25 million in DSM expenses and the associated 1,350 GW.h of annual energy savings associated with all DSM carried out to date are applied to the Export Class. This provided a relatively low cost source of energy (1.8 cents per kW.h) to the Export class.[87]

Hydro's proposed treatment of DSM costs and revenues is incorrect for two reasons:

1. It creates imbalances in the generation supply and sales forecast – effectively double counting the energy related to DSM; and
2. It is not consistent with the Board's directive.

On the matter of double counting, Hydro's proposed treatment creates an imbalance in the energy supply and energy demand assumed in PCOSS08. This imbalance is illustrated in Table 4.3.

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[85] Bill 11, The Winter Heating Cost Control Act, C.C.S.M. c. W165, at section 2(b) sets that one of the purposes of the Act is to:

> b) to provide support for programs and services (i) for electricity and natural gas energy efficiency, enhanced space heat retention and heating efficiency, and (ii) for developing alternatives to natural gas, in order to ensure that sufficient and sustainable energy resources are available in the future.

Section 6(1) of the Act provides that Manitoba Hydro must establish an affordable energy fund sufficient to carry out the following purposes set out at section 6(2) of the Act, i.e., (a) to encourage energy efficiency and conservation; (b) to encourage the use of alternative energy sources, including earth energy; (c) to facilitate research and development of alternative energy sources and innovative energy technologies.

[86] Pages 2349 to 2350 of the transcript May 29, 2006.

[87] Pages 10 and 11. PCOSS08. Appendix 11.1 to the Application.

Table 4.3
Impact on PCOSS08 Energy Supply and Demand
Balance of Hydro's Proposed DSM Treatment[88]

		A	*B*	**C**
		GW.h Prior to Export Adjustments	*less: Directly Assigned to Exports*	**GW.h After Export Adjustments**
1	Thermal Generation	560	*560*	0
2	Hydraulic Generation	29,611		29,611
3	Station Service - Generation	(43)		(43)
4	Total Imports	2,028	*2,028*	0
5	Import Gains	145		145
6	**Total Energy Supply**	**32,301**	*2,588*	**29,713**
7	Sales to Domestic Customers	21,043		21,043
8	PCOSS Adjustment FRWH Derate & S/L Hours	7		7
9	Domestic Losses and Station Service	2,961		2,961
10	DSM at Meter	(176)		(176)
11	Sales to Export Customers and Export losses	8,462	*3,938*	4,524
12	**Total Energy Demand**	**32,298**	3,938	**28,360**
13	*Supply less Demand (line 6 less line 12)*	*3*	*(1,350)*	*1,353*

Column A of Table 4.3 shows the energy supply and energy demand balance assumed in PCOSS08 prior to Hydro's adjustments for costs and sources of supply directly assigned to exports. Column B shows the adjustments Hydro makes to arrive at the export energy served from the generation pool. The adjustments related to Thermal Generation and imports are offsets to both Energy Supply and Energy Demand related to exports (2,588 GW.h). However, the adjustment related to DSM (1,350 GW.h), as applied by Hydro, is only relevant to the Energy Demand portion of the table, and as a result the energy demand:supply relationship becomes unbalanced.

There are two possible measures to correct Hydro's error:

- The less desirable approach to correcting the error would be to maintain the DSM energy as a "credit" to exports, but then adjust each of the domestic classes to "gross up" the load to the levels that would exist had no DSM ever been undertaken. This approach is not advised for two reasons. First, tracking the strict re-allocation of past DSM activities for long periods of time would impose serious technical difficulties. Tracking precise savings from individual DSM programs over time is difficult at the best of times, and given that the results would be

[88] Table based on the response to MIPUG/MH II – 3 e) and PCOSS08.

material to the amounts people are expected to pay through rates, it is likely to become a difficult and contentious area of debate. More importantly, this approach is tantamount to annexing the benefits of all DSM activities undertaken by all classes, as if these activities and all related credit was "purchased" from them at cost to supply exports.

- The more appropriate approach would be to leave the DSM energy credits with the classes that have undertaken the efforts, and not provide exports with a form of priority access to this same power resource. This would retain balance in the cost of service study. In short, this would retain the allocation of DSM costs to exports, but not reallocate the energy, as this energy savings amount would remain as a credit to the classes that undertook the conservation programs.

Not only is the latter correction preferable from a technical perspective, it is consistent with the Board's clear directive. In Order 117/06, the Board directed that Hydro recognize a linkage between energy efficiency, higher exports and higher revenues[89]; however, the Board, specifically directed that this linkage be acknowledged through an allocation of DSM costs, which would include any expenditures arising from any DSM fund established pursuant to Bill 11, as a direct charge against export revenues. The Board provides no discussion of any link to energy savings or the reallocation of energy savings from the classes that participate in DSM activities to serve export loads. There is no direct or implied reference to the inclusion of "energy savings" to be allocated along with the costs of DSM and Bill 11 expenditures.

4.3 RATES FOR GENERAL CONSUMERS

Hydro's application requests rate increases for all general consumer rate classes of 2.9%, with the exception of the Area and Roadway Lighting class. This section reviews Hydro's rate proposals for the General Consumer rate classes.

Hydro's rate proposals for General Consumers are simple, but are not supported by the analysis in this filing. In particular, with the recent investment in a major cost of service review, it would appear timely to ensure that the results of that review are taken into account in rate setting. Specifically, Hydro's proposals fundamentally ignore the results of the COSS, and ignore both Hydro's own rate objectives and the Board's direction in Board Order 143/04.[90]

Hydro identifies its rate objectives as follows:

1. Manitoba Hydro's long-term target is to have all class Revenue Cost Coverage ("RCC") ratios in the range of 95% to 105% and further that all classes should be gradually moved toward RCC's of unity.

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[89] PUB Board Order 117/06 at page 58, notes, "the Board will direct MH to recognize the link between energy efficiency, higher exports and higher aggregate revenues by allocated DM costs as a direct charge against export revenue. Such DSM costs are to include expenditures funded from a Fund that may be established for DSM purposes pursuant to Bill 11."

[90] Manitoba Hydro provided the following response to Coalition/MH-I-45(a): "As stated by the PUB in Order 143/04: *"MH should ensure that all classes are within the ZOR over a reasonable period of time being five to seven years"."* The Zone of Reasonableness (0.95-1.05) established at that time being 0.95 to 1.05)".

2. In conformity with the principles of gradualism and sensitivity to customer impacts, annual adjustments to revenues by customer class are less than two percentage points greater than the overall 2.9% proposed increase in total revenue for the year.
3. Consistent with conservation objectives, the rate schedules propose an inverted rate for the Residential and greater increases to energy charges than demand charges for the General Service Small Demand Medium and Large classes.
4. The combined impact of proposed class average rate increases and adjustments to rate structure results in customer monthly impacts which fall within Manitoba Hydro's guidelines:
    - For Residential customers, no customer will experience a bill increase which exceeds the greater of $3.00 per month or three percentage points more than the class average increase.
    - For General Service customers, no customer will experience an increase in their average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase.[91]

Long-term COSS results[92] are reviewed in more detail in Attachment C.

In addition to its stated long term rate objective of having all class RCC ratios in the range of 95% to 105% with class RCCs gradually moving toward unity, Hydro acknowledges a long-term PUB objective of ensuring that all classes are within the ZOR over a reasonable period of time being five to seven years.[93] The Board also indicated in Order 177/06 that it intended to review costs measured "pre and post" net export revenue. Each of these approaches is noted below.

4.3.1 Cost of Service Results "Post-" Net Export Revenue Allocation

Hydro's cost of service study is prepared with a typical focus on RCC ratios post net export revenue allocation (i.e., as the final right hand column in each study). Looking at these RCC results, Hydro's rate proposals do not address issues related to Residential and General Service customer classes with RCC ratios that do not presently meet established Zone of Reasonableness ("ZOR") tests of 95% to 105%.

Table 4.4 compares the annual rate increases required to achieve RCCs of unity or within the ZOR given the overall level of rate increases assumed in IFF07-1. Note that these adjustments are based on Hydro's PCOSS08, which includes the DSM double counting – no similar results are available for the situation with this item corrected, but the results are not expected to be materially different, at least with respect to direction.

[91] Page 3 line 20 through Page 4 line 7. Tab 10 of the Application.

[92] In PCOSS08, Hydro introduces a new RCC metric that it calls the "RCC Reflecting Retained Earnings Deficiency". Manitoba Hydro states that "...because retained earnings are deficient relative to the target, it is reasonable that RCCs should reflect this deficiency" at page 3, PCOSS08. Hydro confirms that the Retained Earnings Deficiency RCC incorporate as a cost, the forecast deficiency relative to a debt to equity ratio of 75:25 at March 31, 2008 in MIPUG/MH I-26 (b). However Hydro also indicates that the tables are not intended to indicate March 31, 2008 as any meaningful target date for achieving a 75:25 debt to equity ratio in MIPUG/MH I-26 (c) and as such it is not apparent how these Retained Earnings Deficiency RCCs have any useful value in a COS context.

[93] Order 143/04 as restated in response to Coalition/MH I-45 a).

A review of Table 4.4 indicates that the rate increases proposed by Hydro in the Application are not consistent with a rate objective of achieving rates for all customer classes and subclasses with the ZOR and gradually moving toward unity.

Table 4.4
Consistent Annual Rate Changes Required to Achieve RCC and ZOR Targets with IFF-07-1 Proposed Rate Increases[94]

Customer Class	Required Annual % Increase to get all classes and subclasses to unity within 5 years	Required Annual % Increase to get all classes and subclasses to within ZOR in 5 years	Manitoba Hydro's Proposal
Residential	3.78%	2.90%	2.90%
General Service - Small Non Demand	1.92%	2.90%	2.90%
General Service - Small Demand	1.26%	2.40%	2.90%
General Service - Medium	2.65%	2.90%	2.90%
General Service - Large 0 - 30 kV	5.36%	4.11%	2.90%
General Service - Large 30-100 kV	2.04%	2.90%	2.90%
General Service - Large >100kV	0.93%	2.08%	2.90%
Area & Roadway Lighting	1.31%	2.35%	1.00%

Compared to Hydro's rate request, the above analysis indicates that useful application of the results of the recent Cost of Service review suggest at minimum a higher than average rate increase for the GSL 0-30 kV class, and a lower than average increase for the Lighting, GS Small Demand and GSL >100kV classes. To target the 95-105% range within five year, to the extent that the other classes receive a rate change that varies from the overall average to focus instead on achieving unity, the priority would appear to be on securing higher than average increases to the Residential classes, and lower that average increases to the GS Small Non-Demand GS Medium, and GSL 30-100 kV.

It appears that Hydro could largely accommodate either set of rate increases within its two class revenue related rate design objectives:

- Either of these rate proposals would provide better progress toward RCC ratios within the ZOR.
- All of the class revenue adjustments except one would be within two percentage points of the 2.9% general consumer rate increase, as required by Hydro's rate adjustment guidelines.

4.3.2 Cost of Service Results "Pre-" Net Export Revenue Allocation

Hydro has not provided detailed tables of the type indicated in the previous section showing rate changes needed to reach the ZOR for COS results prior to an allocation of net export revenue. The current RCCs for this situation are presented in Table 4.2, which is repeated below as Table 4.5.

[94] Refer to the responses to MIPUG/MH I-30 (a) ii and MIPUG/MH I – 30 (c) ii.

Table 4.5
PCOSS08 Results with Corrected DSM Treatment ($000s)

	Fully Allocated Costs	Total Revenues (after Uniform Rates credit)	Surplus/ (Shortfall) before Export Credits	RCC before Export Credits
Residential	$512,891	$433,136	($79,755)	84.4%
GSS - ND	$100,422	$92,895	($7,527)	92.5%
GSS - D	$116,776	$112,162	($4,614)	96.0%
GSM	$160,478	$144,186	($16,292)	89.8%
GSL 0-30kV	$83,536	$65,925	($17,611)	78.9%
GSL 30-100kV	$38,012	$35,367	($2,645)	93.0%
GSL >100kV	$166,443	$164,004	($2,438)	98.5%
Lighting	$18,919	$19,243	$324	101.7%
SEP	$1,752	$1,561	($191)	89.1%
Total General Comsumers	$1,199,229	$1,068,480	($130,749)	89.1%
Diesel	$11,495	$4,765	($6,730)	41.5%
Total Domestic	$1,210,724	$1,073,245	($137,479)	88.6%

As noted in Table 4.5, compared to the post net export revenue results, the results before net exports show only a limited number of classes within the ZOR; notably the Lighting class (which is slightly above 100%), GSL >100kV and GS Small Demand. These classes can therefore presumably retain reasonable cost coverage results over time with a modest predictable level of rate adjustments.

In the event net export revenue is confirmed to be best targeted towards the type of reserves noted in Section 3 of this evidence, all other classes will require rate increases above typical levels in order to derive from each domestic ratepayer class the amounts noted as “shortfalls” in the above table.

Similar to the results in the previous section on post net export results, the class farthest from achieving full revenue to cost coverage on a percentage basis is GSL 0-30 kV. There is also a significant basis for concern for the Residential class, as the need to target rate adjustments in the range of $80 million (in addition to increases related to Hydro’s revenue requirement) will require diligent pursuit of above average increases to this class.

As a comparative cross-check, this result appears reasonably consistent with the rate pressures being experienced in B.C., which recently concluded a COS and Rate Redesign proceeding[95] that confirmed a three year transition to unity (not ZOR) requiring the following total rate rebalancing over three years: Residential – increase of 11%; GS Small (<35kW) decrease of 18.9%; GS >35kW decrease of 6.4%; Irrigation increase of 20.4%; Streetlights decrease of 20%; Industrial (transmission) decrease of 2.6%.

[95] BCUC Order G-111-07

These rate adjustments are solely to rebalance RCC ratios and do not reflect any increases needed to address overall changes in B.C. Hydro's revenue requirement.

Given the results in this section and the previous section, there is a need to revise Hydro's rate proposals to ensure application of the confirmed Cost of Service results. Hydro should be directed to pursue the rate adjustments in Section 4.3.1 above, so as to target unity within five years (as compared to the BCUC target of unity within three years). In the alternative, in the event an appropriate mechanism can be adopted to develop a protected reserve provision under the control and direction of the Board, the RCC ratios in Section 4.3.2 should be considered as a guide to overall rate adjustments for the foreseeable future until such time as "surplus" export revenues are fully credited to the noted reserves and consequently fully extracted from being credited back to retail customers in the year earned.

In order to ensure continued progress towards the COS analysis levels the Board's directed rate adjustments should not be limited to the single 2008/09 rate change set out in Hydro's Application. Hydro should be directed to implement a second rate adjustment effective April 1, 2009, that is revenue neutral to Hydro, but continues rebalancing between the various classes to continue the progress towards unity within five years and within the rate blocks for the major customer classes to continue progress towards meaningful inverted rates.

5.0 INDUSTRIAL COST-BASED RATE DESIGN

It has long been recognized that Manitoba Hydro's current rate design for industrial customers is inadequate from a number of perspectives:

- **Inverted Rates:** The current industrial rate design does not encourage conservation by providing sufficient price signals at the "margin" (i.e., the last unit of consumption). This type of rate design for industrial customers is not novel among Canadian utilities – Yukon had such in rate in place in the mid-1990s, B.C.'s stepped rate structure is well known and there is presently a cooperative working group between the utility and major customers developing a similar style of rate in Newfoundland. Since at least 2004, evidence provided by MIPUG has stressed the need to move forward on this type of cooperative rate development process.[96]

- **Self-Generation:** The current industrial rates do not encourage customers who have the ability to develop self-generation (such as biomass) at the full export prices Hydro pays to facilities such as Wind Non-Utility Generators ("NUGs"). Hydro continues to insist that industrial customers who develop their own generation not receive fair and equal treatment with wind NUGs.[97]

- **Time-of-Use:** Hydro's industrial rates do not include any time-of-use component, either on a seasonal or a daily basis. While many industrial customers cannot take advantage of time-of-use rates, proper rate design would not penalize these customers (as their cost profile would not change). For customers who have some ability to shift their loads, a rate design that included time-of-use components could reduce Hydro's costs and these cost savings could flow, at least in part, to the load-shifting customer. Properly designed time-of-use rates can provide incentives to optimize the use of the generation and transmission system, resulting in cost savings or increased export revenues, to the benefit of Hydro and customers.

- **Winter Ratchet:** The industrial rates maintain a weak but contentious capacity price signal via the "winter ratchet" that is poorly understood, controversial, and coarse at best. As far back as the 1996 GRA, the Board recognized that "The winter ratchet has been used to signal customers regarding the higher cost of winter capacity; but it is a crude signal which sends far too strong an incentive to some customers and none at all to others."[98]

It is not necessary to belabour these points. Each is well understood as a component of contemporary industrial rate design, and although there are significant details to work out, such details are not barriers to proceeding to develop each concept today. For example, Hydro's claim that a period of 12 to 18

[96] MIPUG evidence of J Osler and P Bowman in the 2004 GRA, page 10 line 28 to page 11 line 9; evidence of P Bowman and A McLaren in the 2006 Cost of Service hearing, Attachment C.
[97] See, for example, MIPUG/MH-I-24(e)(v) and MIPUG/MH-I-23(b).
[98] Board Order 51/96 page 47.

months would be required to develop inverted rates for industrial customers[99] is likely justified if there were bona fide cooperation with the customers and their representatives to accomplish this, similar to the present situation in Newfoundland which is expected to be resolved with a joint proposal to the Newfoundland PUB from the utility and industrial customers developed over a period of about 12 months.

In this regard, it is worth noting that Hydro did bring forward to the PUB an application for time-of-use rates in its November, 1995 GRA, which was rejected by the Board as there had been insufficient discussion with customer groups and "Because of the lack of clarity as to the impact on the General Service Large and Medium classes, the Board will not, at this time, approve the introduction of seasonal rates".[100] Further, "The Board will direct Hydro to prepare a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off-peak and seasonal rates. This report should include consultation with all interested parties and consideration of the rationale and implications of any future phase-out of the winter ratchet."[101]

With progress towards, and eventual adoption of some or all of the above rate designs, Hydro's rate signal to large industrial customers will be significantly enhanced. In particular, if an appropriate revenue-neutral baseline determination approach can be developed, simple economics may serve to enhance the number of opportunities open to firms to become more efficient and cost competitive, consistent with the Board's broad goals of conservation. Given this simple fact, it is not apparent why no serious effort has been expended by Hydro to ensure such rate designs are in service for nearly 15 years after the first modest efforts in this area.

For the present application, Hydro has indicated it is seeking to apply the Industrial rate change entirely to the energy component (and not the demand component) of the rate. Given the substantial outstanding issues arising from the lack of contemporary pricing mechanisms as noted above, Hydro's efforts at improving the price signal are effectively irrelevant, and should be rejected.
Instead, the Board should direct Hydro to establish a logical process for implementing, in consultation with customers, rates that address these contemporary elements of industrial rate design. In the meantime, any rate increases for these customers should be implemented as an equal percentage increase to demand and energy components of the existing rate structure.

[99] Appendix 12.2, page 4
[100] Board Order 51/96 page 48.
[101] Board Order 51/96 page 49.

ATTACHMENT A - RESUMES

PATRICK BOWMAN
PRINCIPAL AND 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. Appear before YUB as expert on revenue requirement matters. 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 in rate proceedings, as well as cost-of-service methodology hearing. 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 (2004-present),** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the 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.

Patrick Bowman Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission	NorthWest Company (commercial customer intervenor)	2004	No
Nunavut Power (Qulliq)	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission	NorthWest Company (commercial customer intervenor)	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2006	No - Negotiated Settlement

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 Consultant/ 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 utilities. Prepare evidence and regulatory filings and review testimony for regulatory proceedings.

- **For Northwest Territories Power Corporation (2000-present)**, primary responsibility for coordinating and developing all aspects of the ratebase and revenue requirement sections for the 2006/08 General Rate Application. Provided technical analysis regarding the Corporation's 2001/03 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, including testimony before the Manitoba Public Utilities Board in the 2006 Cost-of-Service Study hearing.

- **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),** preparation of analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Submitted pre-filed testimony (with Patrick Bowman) on behalf of the Island Industrial Customers in regards to the Newfoundland & Labrador Hydro 2006 General Rate Review before the Board of Commissioners of Public Utilities. Lead consultant for the Industrial Customers in a working group with NLH to develop a marginal cost based rate proposal.

- **For NorthWest Company Limited (2004-2005),** review rate application and rider applications, provide analysis and prepare filings before the Nunavut 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.

ATTACHMENT B - FINANCIAL RESULTS AND FORECASTS

Integrated financial forecasts

In the current proceeding, Manitoba Hydro has provided three different sets of Integrated Financial Forecast (IFF) information as part of its Application:

- IFF06-3 – Consolidated Integrated Financial Forecast[102]
- IFF06-4 Statements[103]
- IFF07-1 Integrated Financial Forecast[104]

Manitoba Hydro notes that the only differences between the IFF-06-3 statements and the IFF-06-4 statements are updates for water conditions and rate increases in 2007/08 through 2009/10.[105] Manitoba Hydro also indicated that it is not updating rate proposals in the Application as a result of IFF-07-1 and that any substantial differences in proposed revenue for 2008/09 between the forecasts would be incorporated into rates filed in future rate applications.[106]

In addition to the financial information filed in this proceeding, information related to previous IFFs helps provide the relevant context to evaluate Hydro's current financial position. IFFs reviewed in this respect have included:

- IFF99-1 which the Board has used as a basis for comparison in some of its questions.[107]
- IFF02-1 which Hydro indicates the MH Board used in setting the debt/equity target of 75:25 by 2011/12.[108]
- IFF03-1 which was included with the 2004 General Rate Application.
- IFF04-1 which was included with Hydro's January 2005 Application in support of a 2.25% conditional interim rate increase.
- IFF-05-1 which is the IFF Hydro submitted in response in MIPUG/MH I – 1 b) when asked to identify the information it considered in making the decision to forego the October 1, 2005 conditionally approved rate increase.

This section contrasts Hydro's actual performance[109] and forecasts with respect to key financial indicators in the different IFFs.[110]

[102] Appendix 5.2 to the Application
[103] Appendix 5.3 to the Application.
[104] Appendix 22 to the Application provided on November 23, 2007.
[105] Coalition/MH I-22 b).
[106] MIPUG/MH I – 1 a).
[107] See PUB/MH I-62 a) through c)
[108] PUB/MH I -23 a).
[109] Actual information in this section is taken from the response to Coalition/MH II-18. Need to confirm
[110] Hydro has provided summaries of some of the IFF information in Appendix 30 to the Application.

Debt to Equity Ratio

Manitoba Hydro notes that its Board adopted a consolidated Debt/Equity target of 75:25 by 2011/12 in IFF02-1.[111] Hydro states that the current consolidated IFF continues to make reasonable progress toward its debt:equity ratio target.[112] However, it should be noted that IFF-07-1, unlike IFF02-1, does not show Hydro achieving that target in 2011/12; Hydro does not even achieve the target within the forecast period.[113]

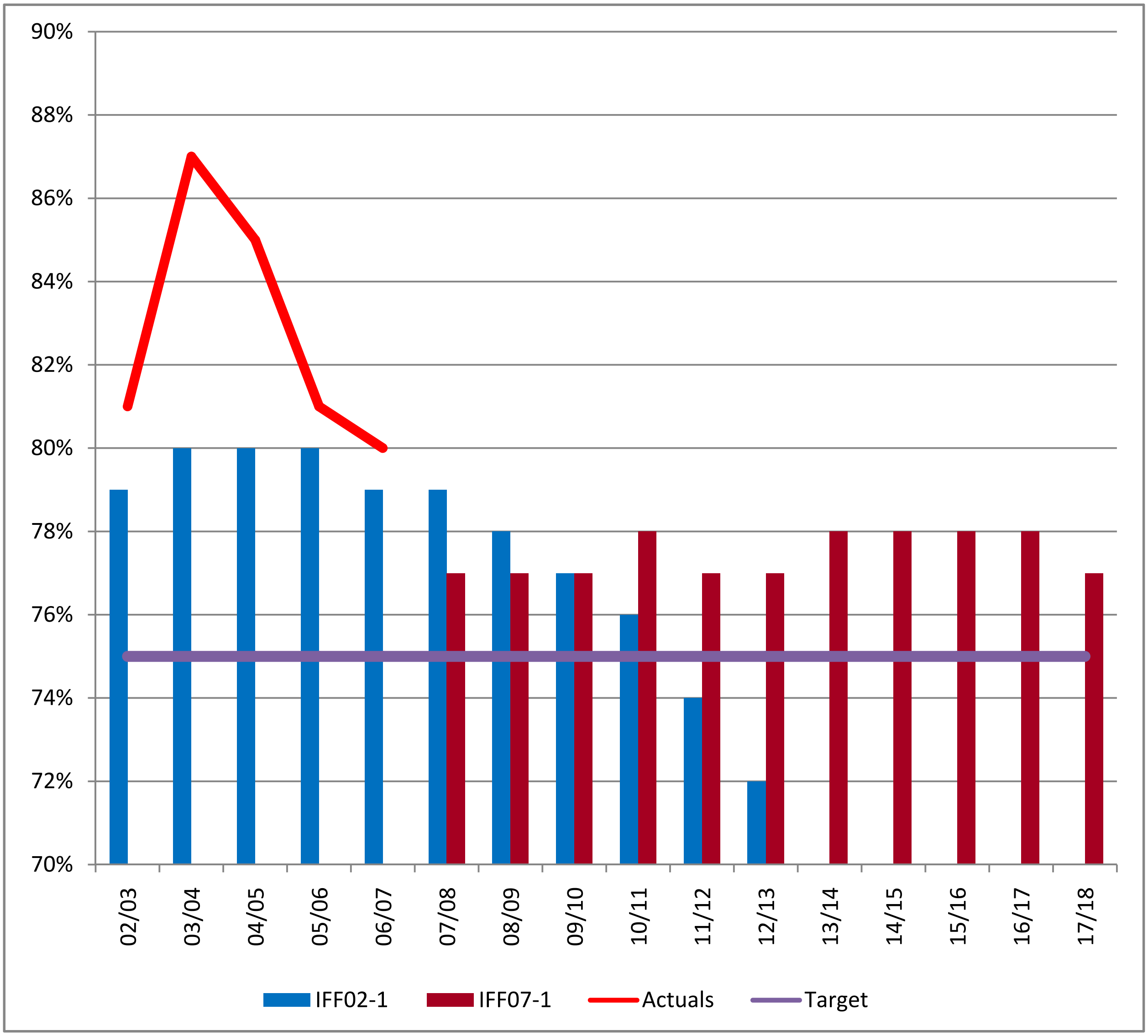
Figure B.1 illustrates a comparison of the debt ratios for electricity operations from IFF02-1 and IFF07-1. Figure B.1 also includes actuals for the years available. A review of Figure B.1 indicates that for the years 2007/08 through 2009/10, IFF07-1 has a lower debt to equity ratio forecast than IFF02-1 (i.e., an improved financial position). However, for years beyond 2009/10 the debt to equity ratio erodes in IFF07-1 compared to IFF02-1 such that IFF07-1 forecasts a debt ratio of 77:23 in 2011/12 compared to 74:26 in IFF02-1.

[111] PUB/MH I -23 a)

[112] Lines 29-30 page 3 of 20 of Tab 5 of the Application as revised December 7, 2007.

[113] Page 14 of IFF-07-1 shows a consolidated debt:equity ratio of 78% in 2011/12 and 77% in 2017/18.

Figure B.1
Comparison of Electricity Operation Debt Ratios



The reasons for this erosion in the debt:equity ratio merit consideration. Hydro gives a number of reasons for the erosion:

- **2002 to 2004 Drought:** As the primary reason, Hydro states that: "The largest single factor contributing to the delay in the achievement of the 75:25 debt/equity target was the 2002 to 2004 drought".[114] At first glance, this assertion does not appear to bear out, as the debt:equity ratio had more than recovered from the drought by the 2007/08 and 2008/09 forecast levels as noted in Figure B-1. A more complete analysis of this reasoning can be completed based on a comparison between the two IFFs which, if Hydro's assertion is correct, should indicate an

[114] PUB/MH I – 63 a).

erosion in the level of retained earnings compared to IFF02-1. This analysis is set out in section B-1 below.

- **Domestic Load Levels and Rates:** A second reason noted is lower than forecast rate increases to domestic customers[115] combined with increasing domestic load that reduces the export revenues.[116] A reasonable point of analysis for the merits of this assertion is a comparison of total revenues, broken down into domestic and export, and also an analysis of the cumulative level of domestic rate increases, per Section B-2 below.

- **Capital Spending:** The third rationale cited by Hydro is increasing capital costs due to load growth, aging equipment and upward market pressures.[117] This is addressed by way of a comparison of Net Plant in Service, in section B-3 of this Attachment.

- **Special Payment to Province of Manitoba:** Finally, Hydro cites the special payment to the Province based on export revenues in the years prior to the drought as a reason for the erosion in financial position. However, this is not a credible reason for Hydro failing to achieve its debt to equity target, given that the special payment to the Province was included in IFF02-1, and further that it was included at a higher level than ultimately materialized.[118] Given this outcome, the lower special payment to the province compared to IFF02-1 should in fact be a contributor to a stronger financial position than forecast at that time, not an erosion.

Following review and testing of each of the above factors, there are only two additional material matters in Hydro's cost structure – annual payments to government, and OM&A Expenses. Outside of an increase to the Provincial debt guarantee fee (from 0.95% to 1.0%)[119] and some potential modest revisions to the measurement and timing of payments for sinking fund management fees, debt guarantee fees, etc., the level of government charges has not increased dramatically during this period.

With respect to OM&A expenses, these are reviewed in Section B-4 of this Attachment.

B-1: Retained Earnings

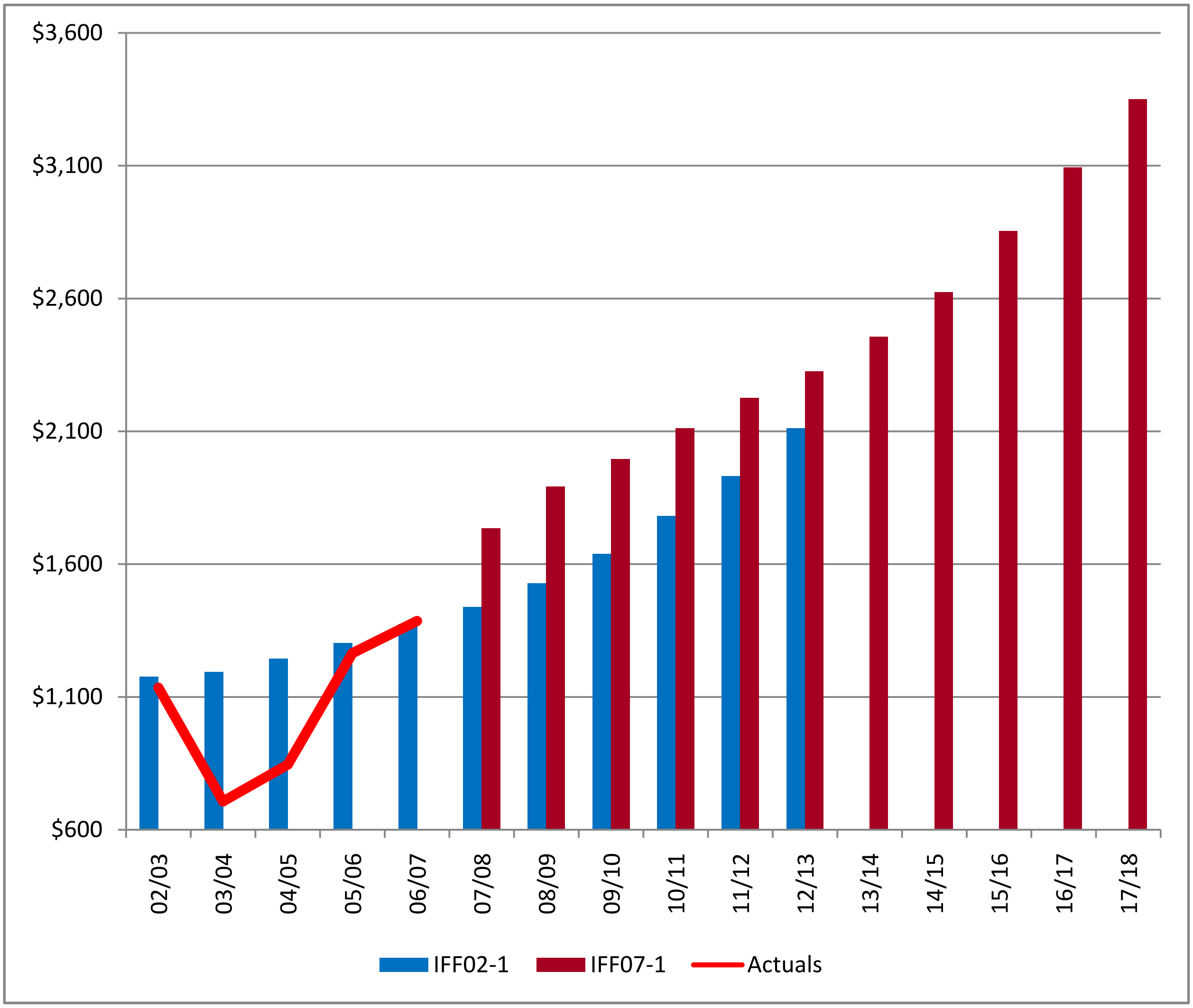
Figure B.1-1 compares actual electric operations retained earnings and forecasts from IFF02-1 and IFF07-1. A review of Figure B.1-1 indicates that from 2002 to 2006, retained earnings were lower on an actual basis compared to those forecast at the time of IFF02-1. However, by 2006/07 the overall level of actual retained earnings is approximately the same as the IFF02-1 forecast ($1.386 billion in actuals compared to $1.374 billion in IFF02-1). Retained earnings forecast for years 2007/08 through 2012/13 are substantially higher for IFF07-1 compared to IFF02-1. Retained earnings forecasts for the 2011/12 fiscal

[115] Refer to PUB/MH I – 63 a).
[116] Coalition/MH-II-18(b)
[117] Refer to PUB/MH I – 63 a).
[118] IFF02-1 notes at page 2 that it forecasts $254 million as total special payments to the province through 2003/04. Actual payments were approximately $204 million as noted in the response to MIPUG/MH I – 29 a).
[119] No justification has been noted for this increase in terms of any increased value to ratepayers of the guarantee, or increased costs to the province of providing their guarantee.

year, Manitoba Hydro's target for achieving the 75% debt ratio, are $295 million higher (15 per cent) in IFF07-1 compared to the same year in IFF02-1.[120] In short, although the drought was a significant event in the years where it occurred, Hydro's recovery from the drought has been quite dramatic and as a result, there are no lingering financial target impacts from the 2002-2004 drought.

[120] $1,931 million in IFF02-1 compared to $2,226 million in IFF07-1.

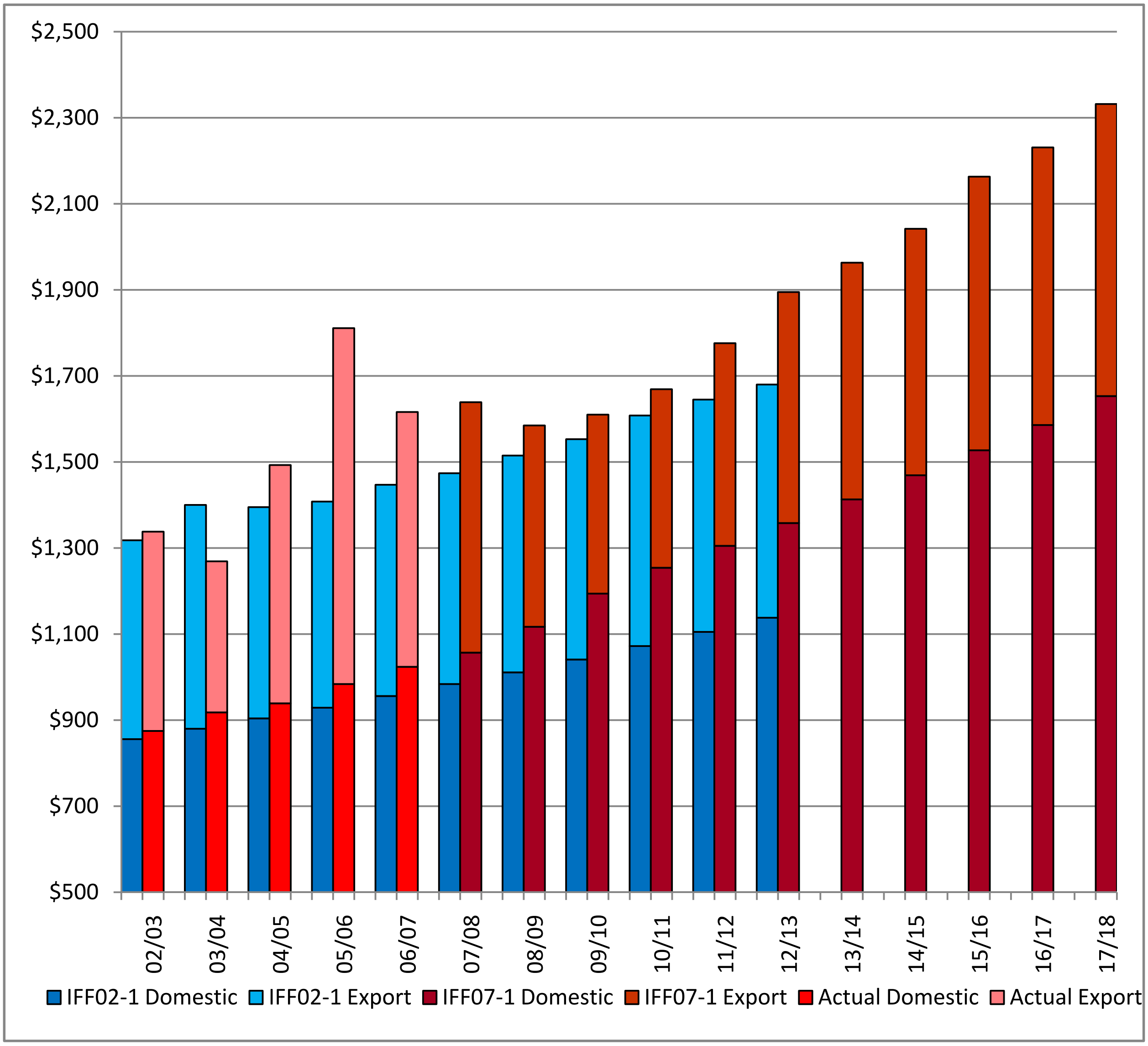
Figure B.1-1
Comparison of Electricity Operation Retained Earnings ($ millions)



B-2: Total Electric Revenues

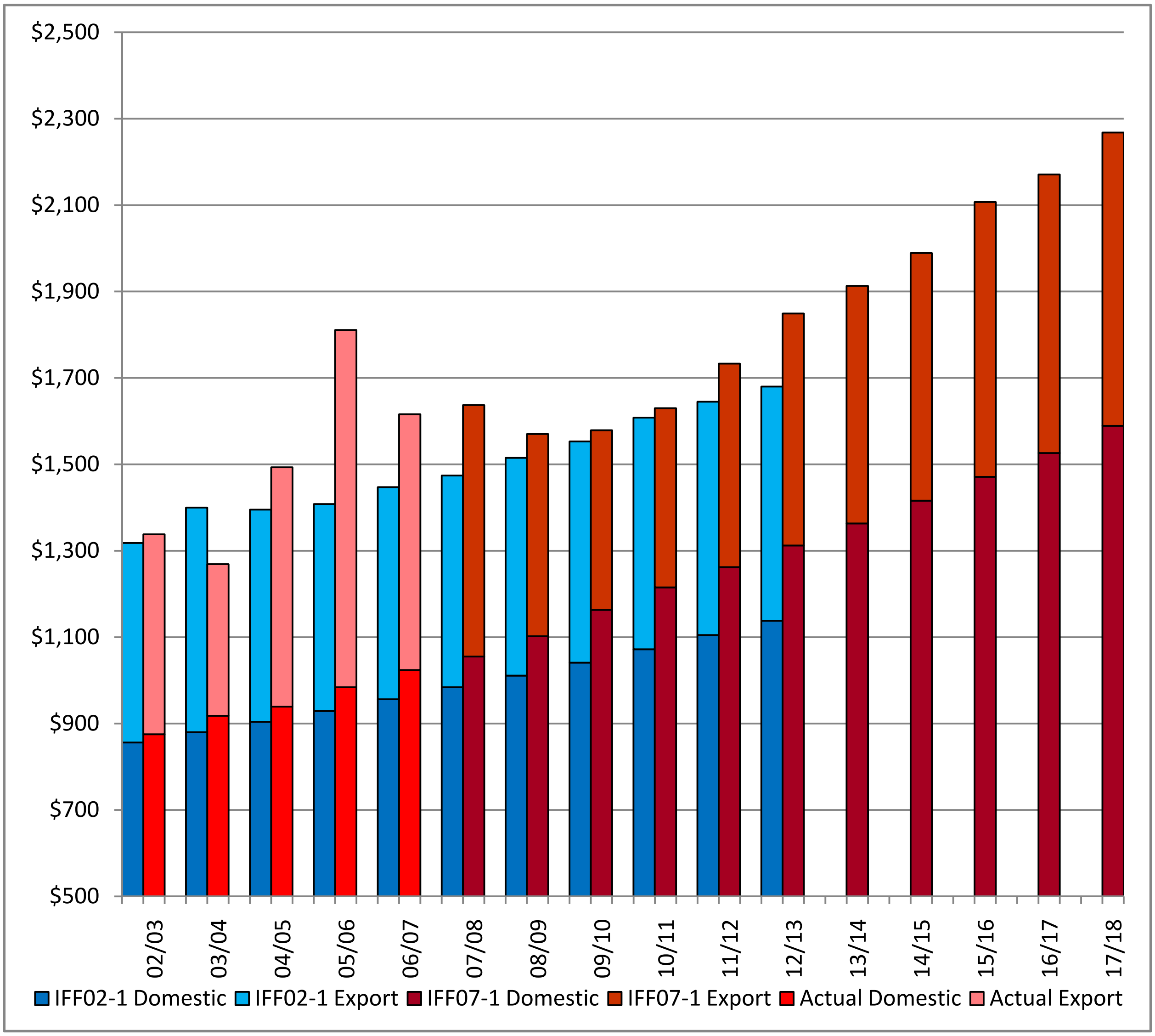
In assessing the situation with respect to overall revenues, Figure B.2-1 compares actual electricity revenues (domestic and exports) to forecast revenues in IFF02-1 and IFF07-1. A review of Figure B.2-1 indicates that while electricity revenues declined on an actual basis in 2003/04 compared to 2001/02 forecasts, actual revenues since that time and forecasts in IFF07-1 have been higher than forecast at the time of IFF02-1.

Figure B.2-1
Comparison of Electricity Operation Revenues ($ millions)



In order to ensure that the results shown in Figure B.2-1 for the IFF07-1 period are not skewed by the proposed marginal-cost-based industrial rate revenues, Figure B.2-2 shows the same information for the IFF07-1 case prepared assuming no new rate for GSL new or expanded loads. In short, the current situation with respect to revenues, even without the new GSL marginal-cost-based rate, still exceeds the rate levels forecast to be required in IFF02-1.

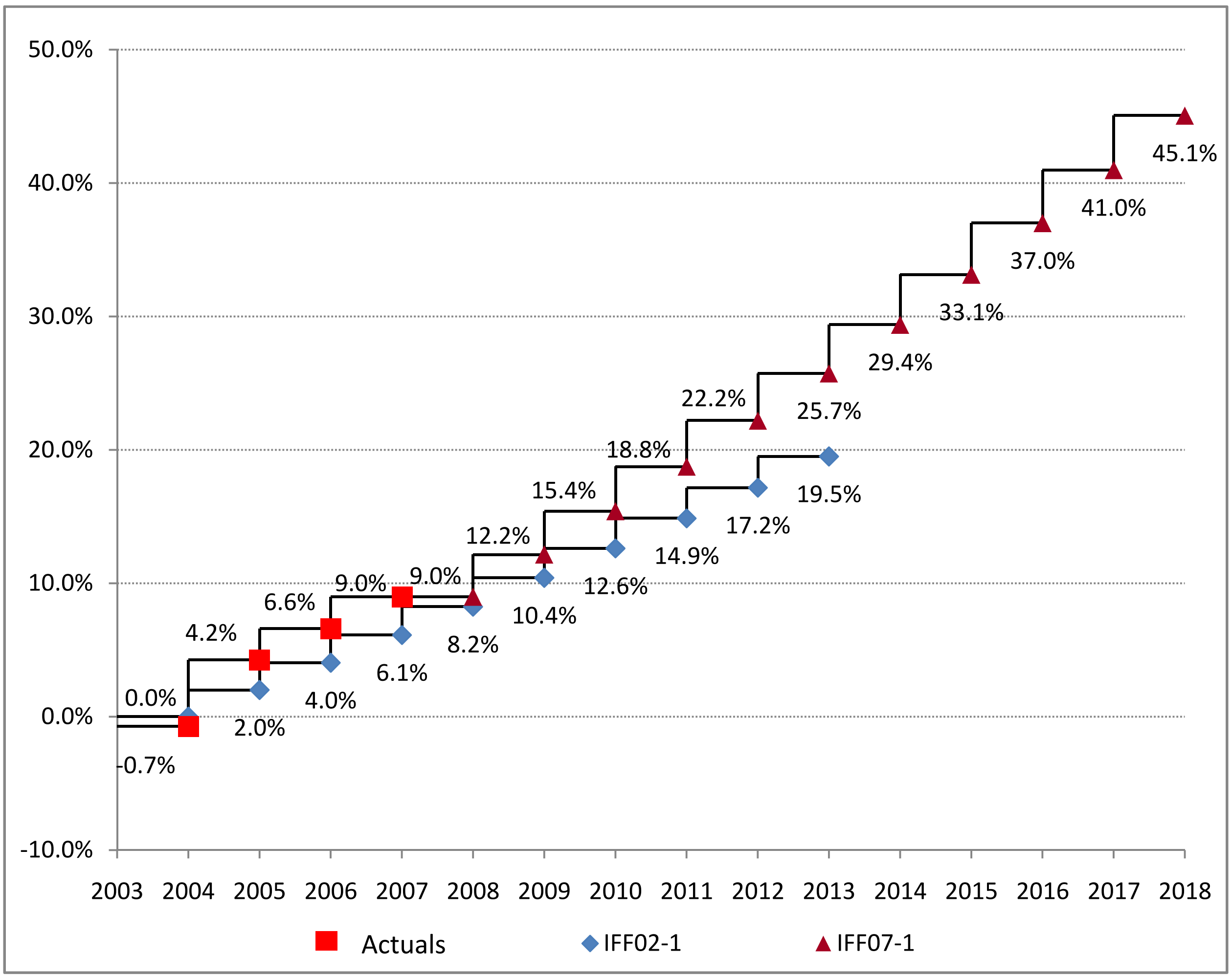
Figure B.2-2
Comparison of Electricity Operation Revenues
Assuming no new rate for GSL New or Expanded Loads[121] ($ millions)



[121] IFF07-1 case without the GSL New or Expanded Loads rate was prepared in response to MIPUG/MH II 2 a) i).

As to the assertion that one of the reasons Hydro has not achieved its debt to equity target is because it has had lower than forecast rate increases, Figure B.2-3 shows the cumulative rate increases for domestic rates assumed in IFF02-1 and actuals plus increases assumed in IFF07-1. Figure B.2-3 includes the slight decrease awarded to GSL and GSS customers in 2003, followed by the subsequent actual rate increases. Overall, Figure B.2-3 shows that, basically throughout the period in question, the cumulative rate increases in IFF07-1 are higher than assumed at the time of IFF02-1. Based on the review of these figures, there is no basis to support a claim that lower than forecast rate increases or revenues are responsible for Hydro not achieving its debt to equity target.

Figure B.2-3
Electricity Operation Cumulative Rate Increase[122]

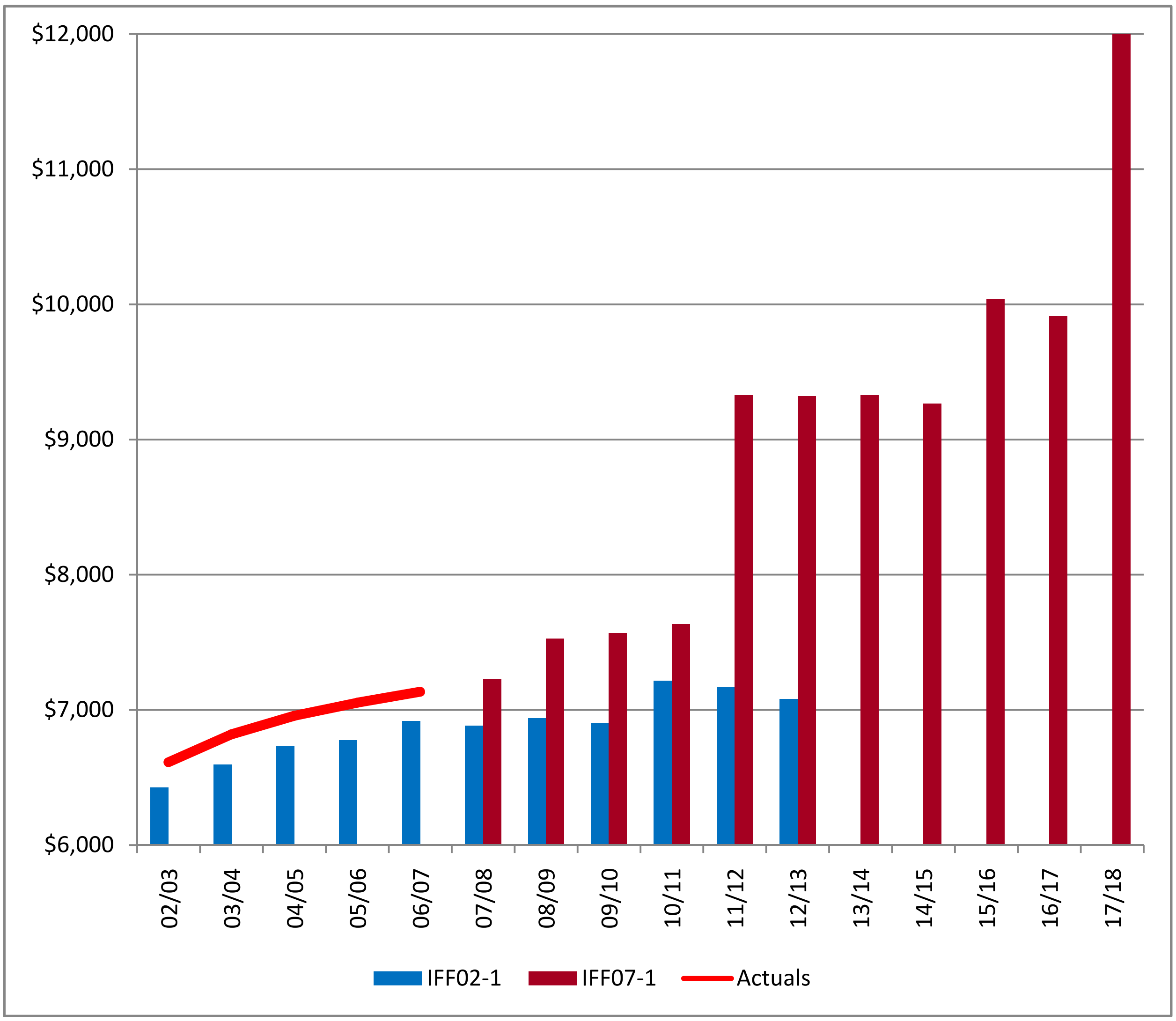


[122] Rate decrease in 2003/04 is estimated based on $6.454 million shown in the response to CAC/MSOS/MH I – 54 from the 2004 GRA divided by electricity general consumer revenues of $901 million in 2003/04 shown in IFF03-1 provided in the response to PUB/MH-8 from the current proceeding. Actuals also reflect the 5% increase effective August 1, 2004; the 2.25% rate increase effective April 1, 2005 and the 2.25% rate increase effective March 1, 2007.

B-3: Net Plant in Service

Figure B.3-1 compares the net plant in service on an actual basis and forecasts in IFF02-1 and IFF07-1. A review of Figure B.3-1 shows that net plant in service has been higher on an actual basis from 2002/03 through 2006/07 than forecast in IFF02-1. IFF07-1 forecasts continue to be higher than IFF02-1 forecasts, particularly late in the forecast period. The forecast for 2011/12 is $2.157 billion (30 per cent) higher in IFF07-1 compared to same forecast year in IFF02-1.[123] This reflects in large part the advanced in-service date for the Wuskwatim Generating station.[124]

Figure B.3-1
Comparison of Electricity Net Plant in Service ($ millions)



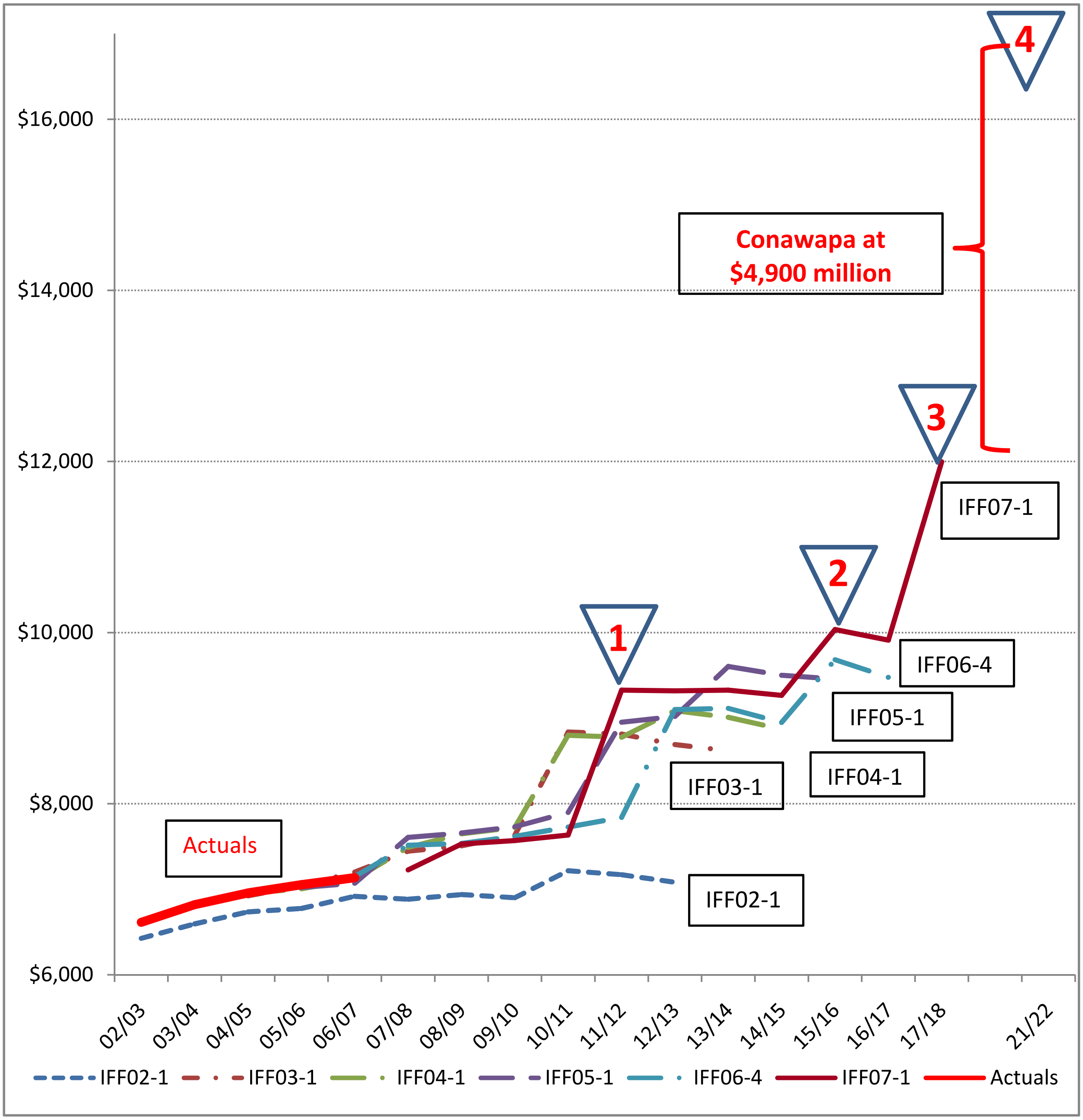
[123] $7.169 billion in IFF02-1 compared to $9.326 billion in IFF07-1.

[124] IFF02-1 assumed a Wuskwatim in-service date of 2020/21 while IFF07-1 assumes an in-service date of 2011/12.

The increase in net plant-in-service is undoubtedly a key driver in the changes to the forecast debt:equity ratios. Due to the nature of the accounting cost profile of capital spending, the impact of this higher level of capital expenditures will have increasing cumulative impacts on the level of net income in the future. Figure B.3-2 shows the net plant in service forecasts for a series of recent IFFs. Three points are identified on the chart that shows the in-service dates assumed in IFF07-1 for major generation and transmission projects: Wuskwatim (point 1); Pointe du Bois (point 2) and Bipole III (point 3). Figure B.3-2 also shows the impact of adding the nearly $5 billion Conawapa project[125] just beyond the last forecast year in IFF07-1.

[125] Refer to IFF07-1 page 33.

Figure B.3-2
Expanded Comparison of Electricity Net Plant in Service ($ millions)



The present situation with respect to capital spending is skewed to some degree by spending on major new generation and transmission projects. Hydro's definition of major projects changes between the various IFF and CEF documents over time, which makes comparisons somewhat difficult. Using a consistent standard definition of major project[126] to net out these special items, it is possible using the

[126] This definition is similar to the one used today by Hydro: includes Brandon CT, Wuskwatim Generation and Transmission, Conawapa, Keeyask/Gull, Wind Generation, Bipole III, Radisson-Riel 500 kV line, Riel 230/500 kV station, Northern AC transmission

data in PUB/MH-II-7(b) to determine the spending on non-major projects. For the consistent period 2002/03 to 2012/13, CEF02 amounts for these non-major projects totalled $3.135 billion, while CEF07 includes $4.411 billion or an increase of $1.275 billion (40%) over CEF02 levels. Given this is for the same period, there is no inflationary effect attributable to this increase.

B-4: Operations, Maintenance & Administration Expense

Figure B.4-1 compares Hydro's Operations, Maintenance & Administration Expense ("OM&A") by year for recent IFFs and actuals through 2006/07. A review of Figure B.6 indicates that Hydro's OM&A forecasts have generally trended higher for each IFF, with IFF07-1 being the highest of the group. The Figure also indicates that actual Operation and Maintenance expenses have been above forecast in almost all cases during this period.

system requirements, Kelsey Generation Improvements, Kettle Generation Improvements, Pointe du Bois Improvements and Upgrade, Pointe du bois and Slave Falls Transmission, Planning and Study Costs, Herblet Lake-The Pas Transmission, and DSM.

Figure B.4-1
Comparison of Operations, Maintenance & Administration Expense ($ millions)

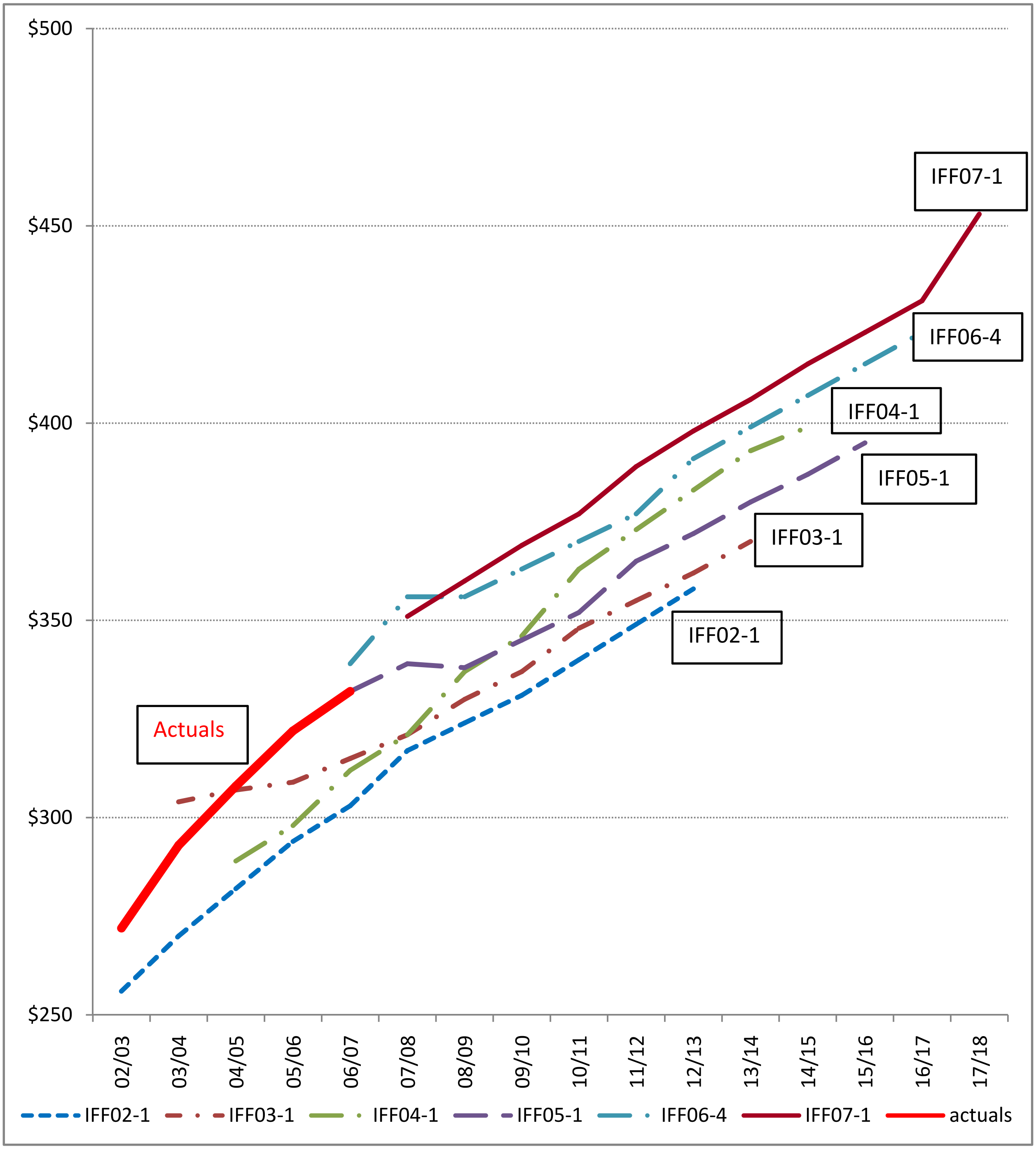


Table B.2 shows the cumulative OM&A expense for the period from 2002/03 through 2012/13 for each IFF, including actuals for the appropriate years for IFF03-1 through IFF07-1. Table B-2 shows an ever increasing amount of OM&A spending for this period, such that total OM&A spending for the years 2002/03 through 2012/13 is 10 per cent higher in IFF07-1 (forecast and actuals) than was forecast in IFF02-1 for the same period (i.e., no inflationary pressures present).

Table B-2
Cumulative OM&A Expense 2002/03-2012/13[127] ($ millions)

OM&A	IFF02-1	IFF03-1	IFF04-1	IFF05-1	IFF06-4	IFF07-1
02/03-12/13	$3,424	$3,560	$3,645	$3,638	$3,747	$3,771

[127] Forecasts taken from each of the referenced IFFs. Actuals are taken from the response to Coalition/MH II – 18 a).

ATTACHMENT C – COST OF SERVICE RESULTS SINCE 1992

Once an overall level of revenues to be recovered from domestic customers is determined, the relative cost responsibility of each customer class is determined based on principles of "cost-of-service". Manitoba Hydro uses a Cost-of-Service Study ("COSS") as a method for determining a fair allocation of its costs to the customers it serves based primarily on principles of cost causation. For more than a decade, Manitoba Hydro's COSS consistently indicated that certain customer classes were paying well above the fair costs to serve their loads while other customer classes paid rates that were not sufficient to recover a fair apportionment of their costs.

In its Order following the 2004 GRA, the Board indicated its concern that the COSS was in a state of flux and in the Board's view, incomplete. As such, the Board could no longer rely on the COSS results for assessing the revenue to cost coverage ratios. The Board directed Hydro to file three separate COSS models, as well as studies that considered the merits and rate impacts of allocating less expensive generation costs to domestic classes with higher generation costs being allocated to domestic and export customers. Hydro was also directed to file a report on the utilization of the Zone of Reasonableness ("ZOR") concept where all customers are moved to unity within five to seven years.[128]

In response to the Board's directive, and following the filing of a General Rate Application that it subsequently withdrew, Hydro filed an application in November 2005 for a revised COSS. The Board heard evidence from Hydro and three intervenors during a hearing process that lasted 11 days in May and June 2006.[129] Following the proceeding, the Board issued Order 117/06, which summarized its views and findings with respect to Hydro's COSS. The total cost to Hydro of the proceeding was approximately $1.282 million.[130]

The following sections review these topics:

- Implementation of Board Directives from Order 117/06.
- Review of Historic RCC Ratios

[128] Refer to pages 96 and 97 of Order 143/04.

[129] As summarized in Board Order 117/06, page 6.

[130] MIPUG/MH II-3 (g). It should be noted that this excludes costs incurred by intervenors who did not apply for cost recovery, including MIPUG.

Implementation of Board Directives from Order 117/06

In Order 117/06, the Board provided six specific directives to Hydro with respect to its COSS method, these were:

- There shall be one export customer class, instead of two export classes recommended by Manitoba Hydro.
- Costs, including direct, indirect, fixed and variable costs, are to be allocated to the export customer class in a manner that reflects cost causation, similar to the methodologies applied to the domestic customer classes. In particular, costs directly assigned to the export class are to include "trading desk" related costs, MAPP and MISO costs, thermal plant costs, water rental and purchased power costs, and other costs that are directly attributable to export sales.
- Twelve SEP time periods are to be used in the determination of marginal cost weighting, rather than the four time periods proposed by MH.
- In addition to the Uniform Rate adjustment, Net Export Revenue is to be further reduced by DSM costs and by the allocation required by Bill 11, prior to allocation to the domestic customer classes.
- The diesel customer class is to be included in the Cost of Service Study, as recommended by Manitoba Hydro.
- Net export revenue is to be allocated to the domestic customer classes, including diesel customers, using the methodology recommended by Manitoba Hydro.[131]

Of these six directives, two simply confirm methods that were recommended by Manitoba Hydro (1 (e) to include the diesel customer class and 1 (f) related to allocation of net export revenue).

Manitoba Hydro provides discussion in PCOSS08 on its approach to developing a COSS that complies with Order 117/06 and characterizes the following as "significant changes from the recommended methodology":

- Allocating Generation costs on the basis of marginal cost weighted energy using twelve SEP time periods rather than four;
- Utilizing a single Export Class and allocate costs to that class in a manner comparable to the allocation of cost to domestic classes;
- Directly assigning the cost of Trading Desk, MAPP and MISO; thermal plant fuel; water rentals and power purchases to the Export Class. Any associated energy is considered to serve export load;
- Directly assigning the costs of Demand Side Management ("DSM"), with the associated DSM energy savings considered to serve the export market. Consequently, the costs of the DSM initiatives are no longer directly assigned to individual customer classes; and
- Allocating Transmission costs on the basis of demand only. The distinction between those lines serving the export market (allocated on energy) and all other transmission lines serving

[131] Order 117/06, page 76.

the export market (allocated on energy) and all other transmission lines (allocated on demand) as done in the recommended version of PCOSS06 is no longer made.[132]

With respect to using 12 SEP periods to calculate the marginal cost weighted energy allocator instead of four, Hydro agreed to this change during the 2006 COSS proceeding.[133] With respect to the allocation of Transmission costs, this change was proposed by Hydro in its rebuttal evidence where Hydro stated:

> Subsequent internal review leads to the conclusion that the Transmission system, whether it provides energy or reliability benefits and whether it serves domestic or export customers, is an integrated system and is more appropriately viewed as a single function. Further, the impact of subfunctionalizing the Transmission system and allocating the two parts on a different basis is minimal; export related Transmission is only 17% of total Transmission, or approximately 3% of the total bulk power system costs to be allocated. Consequently, Manitoba Hydro now believes it would be appropriate to classify the entire Transmission system as demand related and allocate its cost on the basis of the 2 CP allocator.[134]

The other changes noted by Hydro appear to be references to the remaining Board directives. Hydro has created a single export class in the COSS and allocated costs on a consistent basis with the other customer classes. This is consistent with the Board's directives 1 (a) and 1 (b) in Order 117/06.

Hydro's treatment of Trading Desk, MAPP and MISO fees; power purchases and water rentals directly attributable to the export class in PCOSS08 appears to be reasonable and consistent with the Board's directions.

With respect to thermal plant fuel expenses, Hydro notes that it has directly assigned the fuel costs for thermal plants to the export class. The remaining operating and capital costs of thermal plants are considered part of the common generation pool that are allocated to all customer classes, including exports. Hydro indicates that this treatment recognizes to some degree the domestic benefit of thermal facilities and is consistent with treatment in previous COSS of applying only a portion of fuel costs of thermal facilities to exports. 135 There remains an issue with respect to Hydro's approach to implementing the Board's directive regarding the treatment of DSM expenditures. This is addressed in section 4 of this evidence.

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[132] PCOSS08, pages 2 and 3. Appendix 11.1 to the Application.

[133] Transcript page 389 line 11 through page 390 line 10. 2006 COSS proceeding.

[134] Refer to Lines 15-22, page 43 of Manitoba Hydro Rebuttal Evidence dated April 27, 2006. 2006 COSS proceeding.

[135] Refer to PUB/MH I -8 a).

REVENUE TO COST COVERAGE RATIOS

The cost of service studies produced for each Hydro rate review calculate the revenue cost coverage ratio for each customer class and subclass; this is essentially a 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. In Hydro's current COSS, costs are defined to include all revenues required by Hydro, including required contributions to Hydro's reserves.

It has been the Board's long standing practice to use Revenue to Cost ratios ("RCC"s) as a benchmark for evaluating rate proposals for different customer classes. For example, 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 order to evaluate Hydro's rate proposals, the Board has established a Zone of Reasonableness ("ZOR") as a target level for assessing the RCC's and consequently the level of rates charged to each class.

Hydro provides the following discussion with respect to the ZOR:

> The Zone of Reasonableness (ZOR) is a target level established by PUB, with the current target of 0.95 to 1.05 to account for the subjectivity and judgments used in the development of allocators used in a cost of service study (COS). This level is established as it relates to evaluating RCCs relative to Manitoba Hydro's embedded cost of service study.[136]

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 prior to 1996 that equalled 90% to 110%, and revised this range to 95% to 105% in Order 51/96.[137]

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.

[136] Coalition/MH I-45 (b)

[137] 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.

- **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 Order 117/06.

Table C-1 reviews the RCC ratios from 1991/92 to 2007/08.[138] 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 2007/08, the cost of service methodology continues to show this variance.

[138] Using the consistent 1996 COS methodology, including the 1999 adjustments. 2005/06 RCC based on MH revised PCOSS06 as directed by Order 117/06.

Table C-1
Revenue Cost Coverage Ratios 1991/92 to 2007/08
(prior to Hydro's proposed COS methodology revisions)[139]

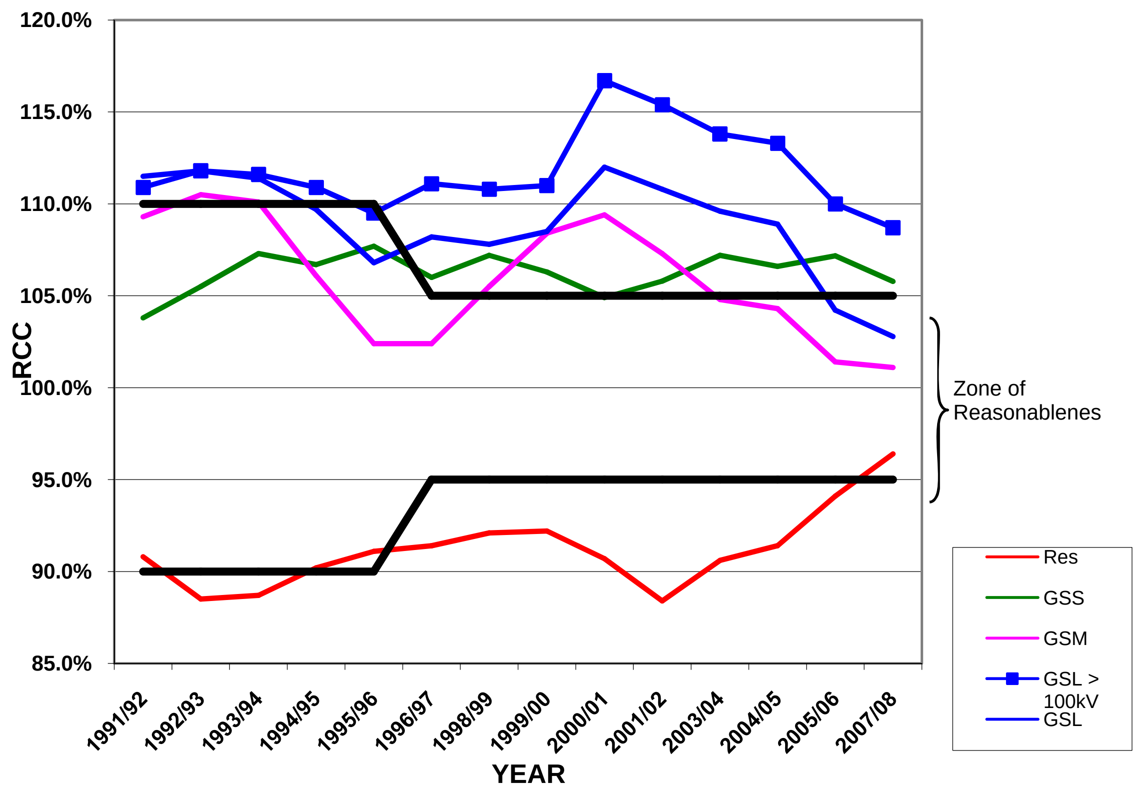
PCOSS	91/92	92/93	93/94	94/95	95/96	96/97	98/99
Res	90.8	88.50%	88.70%	90.20%	91.10%	91.40%	92.10%
GSSmall	103.80%	103.20%	105.60%	105.30%	106.20%	104.50%	107.70%
GSMed	109.30%	110.50%	110.10%	106.10%	102.40%	102.40%	105.50%
GSL<30kv	109.00%	109.70%	109.50%	105.20%	98.50%	100.90%	101.40%
GSL30-100kv	122.50%	117.50%	114.80%	111.80%	109.40%	108.10%	110.30%
GSL>100kv	110.90%	111.80%	111.60%	110.90%	109.50%	111.10%	110.80%
GSCurtail							107.50%
Lighting	118.70%	119.00%	117.00%	119.60%	112.50%	108.80%	93.40%

PCOSS	99/00	00/01	03/04	04/05	05/06	06/07	07/08
Res	92.20%	90.70%	88.40%	90.60%	91.40%	94.10%	96.40%
GSSmall	105.80%	105.40%	105.80%	107.20%	106.60%	107.20%	105.80%
GSMed	108.40%	109.40%	107.30%	104.80%	104.30%	101.40%	101.10%
GSL<30kv	101.20%	102.60%	99.90%	99.90%	100.30%	91.30%	90.40%
GSL30-100kv	112.00%	118.80%	118.50%	109.50%	108.60%	104.70%	103.70%
GSL>100kv	111.00%	116.70%	115.40%	113.80%	113.30%	110.00%	108.70%
GSCurtail	110.30%	114.50%	111.30%	114.60%	112.60%		
Lighting	95.30%	92.00%	97.60%	108.90%	109.80%	107.70%	105.80%

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

[139] 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 was taken from Hydro's revised PCOSS06 as directed per Order 117/06. 2005/06 GSL>100kv including curtailment customers. 2007/08 data was taken from PCOSS08.

Figure C.1
Revenue Cost Coverage Ratios 1991/92 to 2007/08



1. 1991/92-1996/97 data from MIPUG/MH/CR - 2 (b) from the 1996/97 GRA.
2. 1998/99-2001/02 approved data from MIPUG/MH I - 30 (a) from the 2001/02 GRA.
3. 2002/03-2003/04 data from PUB/MH I-28 (c) from the 2003/04 GRA.
4. 2004/05 data from MIPUG/MH I-21(f) from the 2003/04 GRA.
5. 2005/06 data from MH revised PCOSS06 per Order 117/06. GSL>100kv includes the curtailment customers.
6. 2007/08 data from PCOSS08.
7. No Cost of Service Study was done for 1997/98 and 2002/03.

A review of Table A-1 and Figure A-1 clearly indicates that the relative changes to rates have not been successful in moving the rate classes and sub-classes to within the ZOR target of 95%-105%.