PRE-FILED TESTIMONY OF

P. BOWMAN

IN REGARD TO MANITOBA HYDRO 2012/13 and 2013/14

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. MIPUG's current membership and concerns are outlined in Section 1.2. The qualifications of Mr. Bowman are provided in Attachment A.

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's ("Hydro" or "MH") 2012/13 & 2013/14 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 utilities:

- Financial performance from the time of the last Public Utilities Board ("PUB" or "Board") review, forecast financial performance within Hydro's current 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.
- Proposed rates for general consumers and in particular industrial customers.

Consistent with the Board's Decision in Order 98/12 and letter to Manitoba Hydro dated November 6, 2012, this testimony does not address matters related to Hydro's Cost of Service study and methodology (Tab 13 and related Appendices), class differentiated rate increases to the various classes arising from the conclusions of the Cost of Service study (Appendix 10.11), industrial Time of Use Rates (Appendix 10.11) or proposed revisions to the demand billing provisions in the industrial rate schedules (Appendix 10.11). In the PUB's letter dated November 6, 2012, the Board indicated that Manitoba Hydro's Cost of Service Study and Methodology will be reviewed in a separate process to be scheduled for the spring of 2013. The PUB also indicated that as part of that process, it will allow for separate Information Requests to be advanced of all Parties.

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

- The Hydro GRA 2012/13 & 2013/14 General Rate Application, including appendices, and the responses to the majority of Information Requests to Hydro.
- To a limited extent, Hydro's evidence in the 2010/11 & 2011/12 GRA proceeding and earlier rate hearings as they relate to the current proceeding.

The evidence is presented in the following sections:

- Section 2 provides background on the InterGroup assignment, including the main context of the clients (MIPUG), and the main principles for regulation of Manitoba Hydro that were relied upon in this review.
- Section 3 provides an overview of Hydro's Application, focusing on matters of particular interest and relevance to this testimony.
- Section 4 provides comments arising from the review of Manitoba Hydro's financial forecasts.
- Section 5 provides comments on the appropriate rate levels given the results of the review, and on the Curtailable Rate program.

1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

This pre-filed testimony concludes, on the basis of analysis of Hydro's filing and Integrated Financial Forecast ("IFF") 11-2, that the rate increases being sought by Hydro are not required in their entirety. Despite this, a specific alternative rate proposal has not been provided. This is because the current proceeding is expected to continue beyond the point at which Hydro's subsequent year IFF12-1[1] will be made available with considerable updated data.

On the basis of IFF11-2 alone, the evidence in this proceeding does not support the necessity of the full proposed increases of $105 million/year to $117 million/year plus a one-time $25 million transfer from funds presently set aside for ratepayers.

GRA Context

The current GRA occurs as a close follow-up to the longest and most costly PUB hearing in Manitoba Hydro's history (the 2010 GRA and "Risk Review"). That proceeding reviewed, to the extent that information was made available, Hydro's short and long-term plans, and implications for rates over the coming 20 years. While the Board was formally addressing a Hydro rate proposal for a two year test period, the Board ultimately concluded its deliberations based on very large and very long-term considerations, namely that: "the Board is concerned that if MH proceeds with its "preferred development plan" the consequences for Manitoba ratepayers, as to be evidenced in rate increases, may be much higher than MH currently projects"[2]. The Board based its considerations on the fact that "MH's primary objectives include serving domestic load reliably, and at rate levels consistent with Manitoban expectations" but despite this objective, noted "(t)he Board is not at all confident that the risk tolerance

[1] PUB/MH II-27(a).
[2] Board Order 99/11, Page 6.

exhibited by MH is shared by the majority of its ratepayers"[3]. As a result the Board concluded that it would deny Hydro's proposed rate increases, and instead provide a rate decrease from the level of interim rates then being charged (which has yet to be implemented).

In this GRA, Hydro's filing and requested rate approvals can be assessed without such a grand and long-term focus. This is convenient as (a) the information base to understand the grand plans is large, massively complex, and extremely costly and time consuming to review and (b) the information base necessary to complete such a review has not been made available by Hydro[4].

IFF11-2 Rate and Cost Projections

Hydro's costs continue to escalate incrementally at a pace higher than inflation, but slightly slower than in the last GRA. While this cost escalation can be cited as being inflation-driven, it fails to reflect any serious retrenchment of the type Hydro's internal documents indicated the utility was targeting (as reviewed in the prior GRA).

This incremental growth in costs, however, is vastly exacerbated by proposed changes to the timing for recognition of costs. For the GRA test years (2012/13, but also in particular 2013/14), Hydro's project net income of $68 million understates the degree of net income that would arise with more fulsome cost tracking, by as much as $130 million/year. This is comprised of up to $98 million/year due to excessive expensing of costs that appear to be properly related to supporting the capital program and as such are more appropriately capitalized, and $32 million/year due to a proposed adoption of a new depreciation methodology (Equal Life Group, or ELG) that is not suited to Hydro's operation. This $130 million change is equivalent to greater overall rate requirements each year of approximately 11% per year.

Hydro also proposes to eliminate recognition of sizable assets from the calculated reserves that are recorded to benefit ratepayers at times when risks arise, such as droughts. These primarily relate to the PowerSmart DSM programs, which Hydro proposes to no longer account for as having enduring value to the Corporation.

While many of the above changes are cited as being driven by accounting standards, Hydro: (a) has overstated the degree to which accounting standards indeed require the above changes, (b) has typically adopted changes that are the most onerous on current day ratepayers, such as the ELG approach, (c) has offered no options to the Board to mitigate in any way these impacts (unlike basically every other regulated utility or jurisdiction reviewed, which each have adopted measures to help mitigate impacts on ratepayers) and (d) has fundamentally altered the cost profile of capital intensive assets so as to most

[3] Board Order 99/11, Pages 6-7.

[4] Hydro has taken the position that this information is relevant to a future NFAAT review and not to the current GRA.

aggressively recognize their costs early in the asset's life (as well as even before the asset is even in service) despite these assets having lives that can be over a century, with the vast majority of the economic (i.e., ratepayer) benefits occurring in the middle to later years of the asset. Against a backdrop of imminent investment in the largest capital program in the Corporation's history, the inconsistency could not be more stark.

While Hydro's own portrayal of the requirement for rate increases hinges on the recent reductions in export market prices (including a $250 million reduction in 2013/14 as compared to IFF09-1 from the 2010 GRA), the evidence indicates that notable change has been substantially naturally offset by much lower costs for fuel and purchased power in general, and in the case of a drought ($100 million for lower average annual fuel and purchased power plus $60 million in reduced net income serving as an annual contribution towards financial reserves) and the adverse impact that remains is largely offset by savings in interest costs from lower long-term borrowing rates than previously forecast ($70 million).

In short, the current GRA is not an "export market decline" GRA – it a GRA necessitated by failure to control costs, and to a larger degree by proposals to aggressively advance the recognition of capital-related costs, such that today's ratepayers are increasingly burdened with costs related to future capital investment. To be clear, in the event Hydro sought the support of this Board to retain the full approach to cost recognition that was applied in 2008, there would be no current-year requirement for rate increases today and net income could be maintained at levels higher than set out in the IFF11-2.

The IFF financial performance is also hampered by cost impacts of Wuskwatim coming into service, with export prices below that needed to cover all plant costs in the early years (affecting both the interest coverage and Debt:Equity targets), and by increasing levels of long-term debt related to future capital projects such as Conawapa and Keeyask which are not in service in the test years (affecting the Debt:Equity target). This large scale debt has a tendency to skew the Debt:Equity ratio in a manner that makes it appear near-term reserves are becoming less sufficient. This is not true. Reserve levels are growing throughout the IFF period, and would be growing considerably faster if proper cost recognition was adopted. Further, the adequacy of reserves today is vastly better than even two years ago, given the costs of drought have declined massively (by more than 30%) and the "risks" of lower natural gas prices and export markets are now already substantially priced into the IFF forecasts.

Rate Requirements

Despite the above conclusions regarding net income in 2013/14, normal inflationary rate increases are advisable. In particular, the evidence prepared on behalf of MIPUG over the last series of GRA's dating back to 2004 has advocated:

a) Continued focus on efficiency in Hydro's operating costs and "normal capital" program to help minimize costs to ratepayers;

b) Predictable rate transition for customers to reflect where Hydro's costs are going in the medium- to long-term with respect to service to Manitoba customers;

c) The continued provision of reliable and secure reserves that serve to protect ratepayers, and that help ensure orderly predictable rate transitions can also be maintained in the face of adverse events, such as droughts; and

d) A fair allocation of costs and reserve allocations to all classes of domestic ratepayers.

This rate outcome could be achieved, for example, based on IFF11-2 by the following combination of rate outcomes:

1) Finalize rates for 2012/13 and 2013/14 at the current levels (the rates approved as interim as of September 1, 2012). In effect this approves 4.5% in new increases plus eliminates ratepayer entitlement to the 1% rate decrease that would not now be implemented, for a total 5.5%.

2) To maintain the integrity of the previous Board Orders, Hydro not be permitted to retain the approximately $25 million that has accrued in the "ratepayers deferral account" to date. These funds should be returned to customers where practical (through restatement of bills since April 1, 2010), or for classes where this is impractical (e.g., residential, small general service) through one-time measures that beneficially serve the class such as one-time specific funding of DSM programming.

3) Implementing differential rate changes that reflect the conclusions of the Cost of Service study after the second PUB review is completed.

Specific rate recommendations for the current hearing will be provided following review of IFF12-1.

GRA Recommendations

This submission addresses the following specific GRA recommendations:

1) Rate setting assessments at this time should focus on near-term years of the IFF (test years, and possibly 1-2 years subsequent). The remainder of the IFF is atypically speculative and increasingly hypothetical as the forecast goes out. This is because the IFF's reliability in the later years is highly dependent on factors that are: 1) outside of Hydro's control and difficult to predict (e.g. natural gas prices) and 2) that are as-yet uncommitted (such as the Needs for and Alternatives To (NFAAT) conclusions and Government of Manitoba Order-in-Council decisions regarding construction of new power plants). Further, the later years of the IFF are not comprehensible at the necessary level of detail without information that Hydro asserts is NFAAT-related and not GRA-related. Despite this limitation, the later years of the IFF forecast are in no way inconsistent with the recommendations otherwise adopted in this submission.

2) The Board must continue to recognize and address Hydro's escalation in costs year-over-year, particularly if an increasing share of those costs is proposed to be charged to ratepayers in the year incurred (although such cost shifting is recommended to be rejected in this submission).

3) For rate setting calculations, ensure calculations of net income, retained earnings and reserves are portrayed and assessed based on appropriate regulatory principles. To the extent required (i.e., in the event regulatory accounting cannot be accommodated in Hydro's audited financial statements), Hydro should provide the Board with "regulatory" statements and calculations as an alternative to the IFF, for the purposes of assessing rate requirements, based on the following:

    a) Long-term debt linked to projects that are not yet in service should be removed from regulatory Debt:Equity calculations. Accumulated Other Comprehensive Income (AOCI) should also be excluded from Debt:Equity calculations.

    b) Maintain regulatory accounting practices that provide for recognizing amounts spent on PowerSmart and DSM as valuable long-term assets and as part of the valuation of reserves.

    c) Maintain allocations of overhead and administrative and general costs to capital on the basis of full cost accounting, as permitted by CGAAP, consistent with approaches used by Hydro in the 2008-2010 period.

4) Hydro should proceed with eliminating net salvage from depreciation rates, as recommended by Gannett Fleming.

5) Hydro should reject the Equal Life Group (ELG) method of depreciation, in favour of retaining the Average Service Life (ASL) method consistent with other Crown owned and hydro dominated

utilities. While the ASL is a well-accepted straight-line method of depreciation, the ELG approach instead yields far higher costs in the early years than ASL, which is inconsistent with the economic cost profile of capital intensive bulk power assets, like hydro stations.

6) Hydro should be permitted to eliminate Options C from the Curtailable Rate Program (CRP) but not to reduce the subscription caps on Options A or R.

7) Broader options for industrial customer cost management, such as self-generation, and demand-response, should be investigated and pursued by Hydro, in cooperation with affected customers.

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

2.0 THE INTERGROUP ASSIGNMENT

InterGroup has been retained by MIPUG to review Hydro's GRA in light of the concerns of industrial customers, and in light of normal regulatory principles and considerations relevant to Hydro, in particular as a rate-regulated, Crown-owned and hydropower generation dominated utility.

This section sets out the over-riding considerations that guided InterGroup's review of Hydro's filing.

2.1 OVERVIEW OF MIPUG MEMBERSHIP AND CONCERNS

InterGroup set out to review Hydro's GRA in light of the facts and concerns expressed by the MIPUG members. This section sets out InterGroup's understanding of the key concerns of MIPUG which guided the InterGroup review.

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:

- Vale, Thompson;
- HudBay Minerals Inc., Flin Flon;
- Tolko Industries Ltd., The Pas;
- Canexus Chemicals, Brandon;
- Koch Fertilizer Canada ULC, Brandon;
- ERCO Worldwide, Virden;
- Gerdau Long Steel North America – Manitoba Mill, Selkirk;
- Amsted Rail - Griffin Wheel Company, Winnipeg;
- Enbridge Pipelines Inc., Southern Manitoba; and
- TransCanada Keystone Pipeline, Southern Manitoba.

The majority of the MIPUG load is in the >100 kV class; however, MIPUG also includes companies who represent over half of the smaller 30-100 kV class.

The MIPUG members compiled information on each of the member companies for an economic impact study in the spring of 2012, as an update to earlier 2005 and 2008 versions that had previously been filed with the Board[5]. According to the information available at the time the 2012 economic impact study update was undertaken, MIPUG member companies:

- Provide approximately 4,300 full-time jobs and employ 1,300 contract workers;
- Contributed almost $2.3 billion to provincial GDP;
- Contributed $260 million in taxes to local governments, Manitoba and Canada; and
- Have $6.5 billion in capital investments in Manitoba.

In short, the study indicates MIPUG companies are significant contributors to Manitoba's economy and are particularly important to some of Manitoba's larger communities outside of Winnipeg. Nearly all of the 4,300 full-time and 1,300 contract jobs are cited as being located outside of Winnipeg. Many MIPUG companies are the largest employers in their respective communities. The combined annual sales of MIPUG companies total almost $2.6 billion. MIPUG members 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.
- The need to ensure Hydro's long-term system planning promotes rate stability and predictability over the long-term.
- 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.

[5] The 2005 Economic Impact of the Manitoba Industrial Power Users Group was requested in 2008/09 GRA proceeding. The IR response (MIPUG/MH-1) indicated it was being updated and the 2008 update was provided as Exhibit MIPUG-9 on March 25, 2008.

- Assurance that general customer rates are reasonable within the context of long-term cost projections and provision of secure financial reserves that are appropriate in light of Hydro's past practice and the specifics of the Manitoba market.
- Assurance that rates to each customers class reflect Cost of Service calculated in accordance with principles appropriate to Canadian regulatory practice for Crown electric utilities.

MIPUG has indicated that the basis for their intervention is that electricity prices matter greatly to industrial customers. MIPUG members have indicated that they are concerned about persistent electricity rate increases undermining the advantage of operating in Manitoba. Cost-based, stable and predictable electricity prices are cited as being critical to the success of Manitoba industry and provide a competitive advantage and help to offset some of the challenges of operating in Manitoba, including climate and distance to market. MIPUG companies have made long-term investments in Manitoba, based on expectations of stable, cost-based rates, clear and transparent regulation, and reliable service.

In addition to the need to maintain stable, cost-based rates in Manitoba, MIPUG members have expressed concerns regarding their competitiveness in relation to sister plants and their competitors. While Manitoba Hydro indicates they offer some of the lowest published electricity rates in North America, MIPUG companies have been clear that this is not the same as being the lowest cost for power. Members are aware of significant rate options that exist in other locations, which result in the members companies having access to lower overall costs for power than they have in Manitoba. MIPUG members who own plants with operational flexibility also indicate that their sister operations in other parts of Canada or the United States can often alter their loads to access low daily or seasonal market prices and avoid or capture the benefits of times of high market prices. Similarly, for those companies who can generate some proportion of their own power, other jurisdictions offer the opportunity to receive economic price incentives on that generation (similar to what Manitoba Hydro offers to wind IPPs, but specifically prohibits with respect to industrial generators). With this flexibility, some members indicate that sister or competitor plants in other jurisdictions are able to achieve a lower overall power cost profile than exists in Manitoba, despite those other jurisdictions having higher published rates.

A similar problem was noted during the mid-1990s when Hydro similarly claimed to have the lowest published rates, but MIPUG member experiences made clear that Manitoba was not necessarily the overall lowest cost for power. In that instance, Manitoba Hydro worked with MIPUG members to develop rate options that provide a long-term benefit for Hydro, industry and customers in other rate classes, most notably the Curtailable Rate Program. This program allows Manitoba Hydro to curtail electricity service to certain industrial users during emergency supply conditions, to help ensure reliability of supply to all other users, avoid additional backup generation costs, while providing financial incentives to the participating industrial customer. This is an example of successful cooperation to help industry and Hydro reduce costs, but in the current GRA that curtailable program is proposed to be scaled back. No new rates or programs of this type, which are of large scale interest to industry, have been developed in Manitoba since that time. MIPUG members have indicated that there could be benefits from new options that increase the flexibility for firms to manage their power costs, such as Demand-Response type programs that exist in other jurisdictions.

As context to InterGroup's review, it is noted that in the utility's 2007 and 2008 load forecasts, Hydro's forecast load growth for the >100 kV customer class was extraordinary, with some forecasts indicating an increase in industrial load from historic levels of approximately 5 TW.h[6] to 7 TW.h by 2018. This led to initiatives to find ways to curb this growth. It was at this time that Hydro proposed the contentious Energy Intensive Industrial Rate (EIIR)[7]. Since that time, the unrealistic load growth forecasts have been moderated (forecasts now show current loads below 5 TW.h and struggling to re-achieve this level by 2020)[8], as has Hydro's approach to addressing large industrial customer rate issues. The EIIR proposal, which was viewed by industry as punitive and unprecedented, has been withdrawn, and newer rate re-designs based on more balanced and revenue-neutral concepts are now being proposed.

2.2 RATE MAKING PRINCIPLES FOR A HYDRO-ELECTRIC CROWN UTILITY

This testimony has been prepared taking into account regulatory and rate making principles appropriate to Manitoba Hydro as a Crown-owned and hydro generation dominated utility. This section reviews the key principles and their rationale.

2.2.1 Background

As a general principle, prices for electricity throughout Canada are set based on one of the following three basic approaches – 1) based on markets such as in Alberta or Ontario (with government subsidies or rebates at times being provided to certain groups); 2) by government, based on political considerations, such as in Quebec for bulk power, in Nunavut, and in Manitoba prior to the *Crown Corporations Public Review and Accountability Act* of the late 1980s[9]; or 3) based on regulated cost-of-service approaches, such as in British Columbia, Yukon, Northwest Territories, Newfoundland, and Nova Scotia[10].

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[6] 1 TW.h is 1,000 GW.h.
[7] The Energy Intensive Industrial Rate was filed with the PUB by Hydro on September 30, 2008, http://www.hydro.mb.ca/regulatory_affairs/electric/energy_intensive_rate_app/eiira.shtml.
[8] MIPUG/MH I-40(a).
[9] This approach is also similar to that used by other non-electric utilities such as many Canadian water and sewer services.
[10] In some cases, only a portion of the respective utility's rates or tolls are regulated based on cost-of-service principles.

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

The premise of rate regulation is that customers generally, or a single class of customers specifically, require protection from a monopoly supplier who could, in the absence of a principled decision on the fairness of rates, charge them prices that are unreasonable. The "reasonableness" in this context represents a number of considerations, including:

- The price for service to customers overall reflects the costs of providing that service[11] ("Revenue Requirement").
- The costs are measured based on the assets that are used and useful in the period in question, and at a level that reflects prudency in the costs of acquiring the asset (the "Used and Useful" and "Prudent Investment" tests)[12].
- The costs are allocated on a principled basis to the various classes of customers that share in receiving service from a single system ("Cost of Service").
- The rates ultimately charged are to yield the appropriate revenues to Hydro under varying conditions and meet a series of important rate objectives ("Rate Design").

2.2.2 Revenue Requirement and the Used and Useful Test

Hydro's revenue requirement is approved by the PUB and includes reasonable costs required to run the utility. The PUB has the ability to determine which costs are reasonable versus which costs are not. *The Crown Corporations Public Review and Accountability Act* identifies items that the Public Utilities Board may take into consideration when setting rates[13]:

(i) The amount required to provide sufficient moneys to cover operating, maintenance and administration expenses of the corporation;

(ii) Interest and expenses on debt incurred for the purposes of the corporation by the government;

(iii) Interest on debt incurred by the corporation;

(iv) Reserves for replacement, renewal and obsolescence of works of the corporation;

[11] See, for example, Bonbright, J.C., 1960, "Chapter IV – Cost of Service as the Basic Standard of Reasonableness".
[12] Charles F. Phillips, The Regulation of Public Utilities (3rd. ed,) at pp. 340.
[13] The *Crown Corporations Public Review and Accountability Act*, Part IV, Public Utilities Board Review of Rates, Section 26 (2).

(v) Any other reserves that are necessary for the maintenance, operation, and replacement of works of the corporation;

(vi) Liabilities of the corporation for pension benefits and other employee benefit programs;

(vii) Any other payments that are required to be made out of the revenue of the corporation;

(viii) Any compelling policy considerations that the board considers relevant to the matter; and

(ix) Any other factors that the board considers relevant to the matter.

The PUB makes the final determination regarding what costs are reasonable and recoverable by Manitoba Hydro from domestic ratepayers. The PUB's concern must reside with determining what amounts of Hydro's spending (all, or potentially not all) is ultimately recovered from ratepayers, and when.

In making this determination, the PUB must look to the years in question (the "test years")[14], and to a lesser degree, to relevant subsequent periods to the extent needed to take into account the critical concepts of rate stability. For example, Bonbright notes, in relation to the instability of rates that can arise with an over-focus on short-run costs that such pricing methods should not "deprive consumers of those expectations of reasonable continuity of rates on which they must rely in order to make rational advance preparations for the use of services"[15].

2.2.3 Cost of Service and Rate Design

In order to fulfill normal ratemaking principles, the relative levels of rates charged to various customer classes by Manitoba Hydro are to be developed based on principles of "cost of service", or determining a fair allocation of Hydro's costs to the various classes based on a consistent set of principles. This retains the concept of used and useful – for example, if a customer class does not use a component of the system (e.g., distribution), its rates are not to include the costs of that component of the system; likewise if only one class uses assets (such as streetlights) all costs related to those assets are to be allocated to the relevant class.

Based on these allocated costs, a rate design can be developed to recover the appropriate level of costs from the various customer classes, as well as achieve key objectives such as stability, efficiency, etc.

[14] For example, as far back as 1922, the New York Public Service Commission noted: "Consumers should not pay in rates for property not presently concerned in the service rendered, unless- (1) Conditions exist pointing to its immediate future use; or (2) Unless the property is such that it should be maintained for reasonable emergency or substitute service; and in studying these two exceptions the economic factor should be carefully considered." Elmira Water, Light & R.R., 1922D Pub. Util. Rep. (PUR) 231, 238.

[15] Bonbright, J.C., 1960, Page 396-397.

An analysis of a Cost of Service Study is required in order to ensure that different rates which collectively result in generating sufficient revenue for Hydro are individually just and reasonable to each class of ratepayer.

2.2.4 "Heritage Resources" and Hydraulic Generation

The above principles and excerpts from the literature highlight normal utility regulation and ratemaking principles as they apply to the power utility industry generally and in particular to private utilities. A unique additional consideration is at work in jurisdictions such as Manitoba (and similarly in systems such as Quebec) where the development of power systems has not been pursued on a private investor/equity return basis. This is a common feature of hydro dominated systems, given the unique nature of hydro projects:

- **Capital Required:** Hydro projects require massive commitments of capital. If this capital is to be sourced from investors (equity) it requires a considerable return to attract sufficient investment to complete a large project. Also the nature of very capital-intensive projects is that there is a very high "fixed" annual cost related to the investment, and low operating costs. For example, a typical investment by Hydro today in each $1 billion project likely requires 1%-2.5% of the capital cost (on average) for depreciation and a further 5% for interest cost[16], for a minimum net cost in the first year of $60-$75 million (if not offset by new revenue, this would mean a 5%-6% impact on rates[17]).
- **Low Initial Returns:** Hydro projects would normally be expected have extremely low (or zero, or slightly negative) economic returns in the near-term, but basically assured to have high returns over the medium to very long-term. Government entities, relying on a debt guarantee of the citizenry can find these economics attractive. This pattern of economic returns however, is not generally attractive to private sector investors needing to pay annual dividends to investors.
- **Annual Risk:** Hydro projects have no assurance of economic returns in any single given year, or even in any single decade, due to water flow variation. It is possible to calculate a very favourable return statistically over any longer-term period, but the duration of drought risk, with its attendant cost and cash flow challenges, would be unattractive to private investors, or would demand excessive risk premiums on equity returns.

In short, hydro projects are exceedingly challenging economic projects to develop, and are exceedingly risky from year to year due to water flows, but are in fact among the lowest risk (if not the lowest risk) power projects available over any longer-term horizon. While a comparable capacity of thermal plant

[16] Based on the projected 2013/14 interest rate of 4.05% plus 1% guarantee fee.
[17] At approximately $12 million per percentage point of rate increase.

would cost a fraction of the cost of hydro plants, and bring a far more stable annual cost profile year-to-year over the short-term, the intense long-term risk with respect to fuel prices and almost certain higher life cycle cost over the full plant life cycle make such plants more attractive to investors, and much less attractive over the long-term to ratepayers.

For a jurisdiction with a good hydro potential, there exists a potentially excellent development opportunity, but a very challenging investment opportunity. If the returns are permitted to be very high, this development can attract private capital. More typically, jurisdictions in Canada with this resource profile elect to use the "Patient Capital" that is more characteristic of provincial governments (or aboriginal governments) including low-cost borrowings that can be available to provincial governments (even on a highly leveraged basis) when backed by the full faith and credit of the citizenry. This latter government entity approach leads to far more advantageous rates, particularly for a cost-based Crown utility like Manitoba Hydro.

Against this backdrop, an overriding principle that must be brought to bear in regulation is ensuring that the costs of these very large developments (e.g., costs to develop new projects, costs to depreciate existing projects) are recognized in the appropriate time period, and in particular not in advance of when the bulk of the economic benefits of the plant arise. With exceptional long-term economics that get better with time, one role for regulation is to ensure that today's ratepayers are not being burdened with costs that are appropriately collected from ratepayers later in a hydro plant's life when the economic prospects are vastly improved. This principle is front-and-centre in the current GRA.

It is also important to acknowledge the fundamental tenets underlying electricity pricing and policy existing in Manitoba since at least the 1970s[18]. Manitoba electricity prices are based on the costs required to operate the public power electricity system put in place in past years. These prices reflect the underlying "heritage resources" developed and paid for by Manitoba electricity consumers[19] who took on the costs and risks related to major generation and transmission developments (both one-time investment risks, as well as ongoing risks related to water flows, plant performance, etc.). In this regard, the generation and transmission resources currently in place (the "bulk power" system) represent the entitlements of ratepayers to attractive and stable electricity prices. Export revenues have been integral to this policy approach, in that the ability to export power enables development (and in some cases allows advancement of development) of large northern hydro stations, in excess of what would be

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

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

required for solely domestic requirements at any given point in time[20]. This allows larger scale and more economic plants to be developed, and allows rates to be lower than they would otherwise be (were the major hydro developments not otherwise possible) and more stable (since fluctuations and risks related to Manitoba load levels can be offset in part by complementary changes to quantity of power exported, and since the ongoing costs of hydraulic generation are not subject to fuel price fluctuations).

Similarly, these same basic tenets have been the basis for the current Manitoba initiatives to develop new renewable hydro. These plans are founded on the ability to construct generation projects sooner than they would otherwise be triggered for solely domestic use, and to use the intervening "advancement" period to make valuable sales to export markets. As such, Hydro's supply is bolstered, the utility has increased flexibility to address such situations as unexpected load growth, and the new hydro plants are constructed earlier, and at a lower cost than would otherwise arise (due to inflation) and to have the investment partially "paid down" by early years export sales. In each case, the premise put forward by Hydro (such as at the Wuskwatim CEC hearings) is that these generation investments are aimed at maintaining stable and low cost electricity for Manitobans, along with all the associated advantages for cost-of-living, jobs and investments, and development of renewable public resources (and in the current hydro developments, opportunities for northern community investment). Unlike major new generation brought on-line in places such as Ontario in past decades, which resulted in major rate increases, Manitoba Hydro continues to indicate that its intent is to develop new generation such that there are long-term beneficial impacts on Manitoba ratepayers, but no near-term adverse impacts.

2.2.5 The Role of Reserves

With the above noted cost profile for hydro developments, the final component of the regulatory framework becomes determining an appropriate level of reserves. A Crown utility has no investor or shareholder "equity" *per se*. While there is a mathematical benefit to paying down the utility's debt (lower interest payments), there is no absolute guidance from stock markets, or lenders, or business theory for Hydro to have a specific balance of debt. The assets are paid for as they are being used by ratepayers, and the debt financing of the assets is being retired commensurate with this depreciation. Lenders do not require an equity cushion to know they will be repaid (they moreso require a principled rate regulator, a rate regime that appears able to absorb some degree of higher costs in the event adverse events arise, and a provincial government guarantee[21]). Many Crown utilities (both electrical and other) have operated for long periods with little to no "equity".

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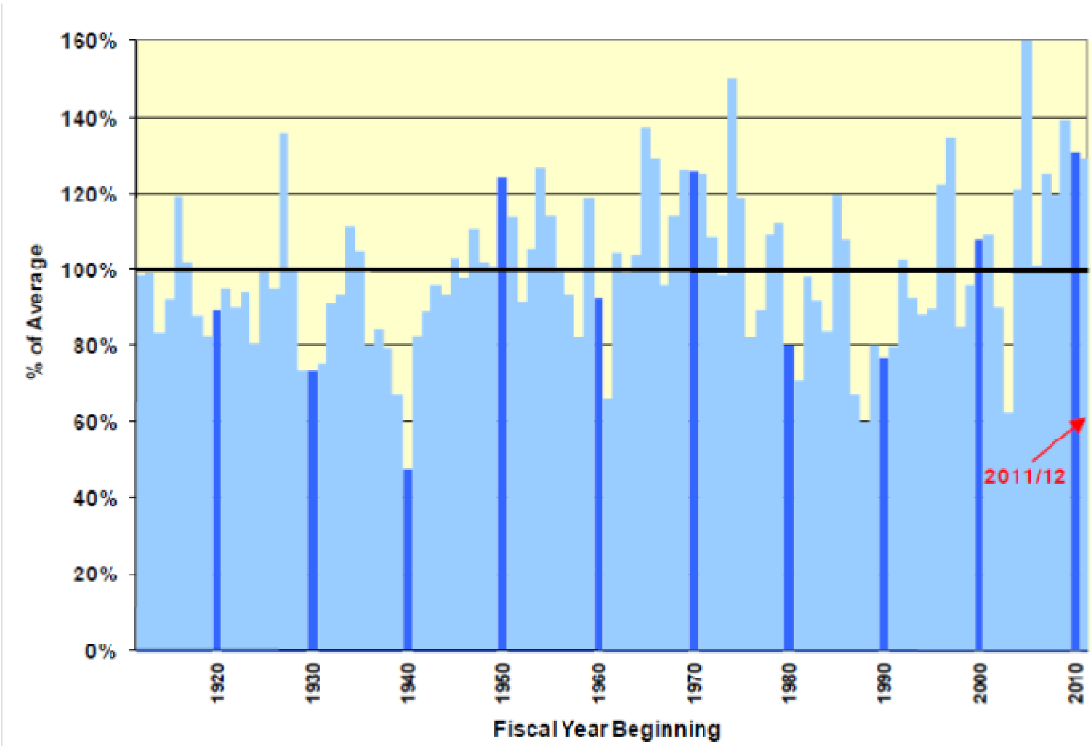
[20] This basic relationship is set out in detail in the PUB's Report to the Minister regarding Manitoba Hydro's 1990 Capital Plan, Section 3 and Page 5-4.

[21] Each of these criteria exist in Manitoba, with a longstanding PUB, relatively low power rates, and the guarantee of the Government of Manitoba on Hydro's debt.

Despite this lack of clear guidance, it is clear that Hydro requires relatively substantial reserves. Hydro's chart at page 22 of Tab 9 is reproduced below as Figure 2-1 to illustrate the degree of water flow variability inherent in its system.

Figure 2-1: Historical Water Supply: System Inflows[22]



The chart in Figure 2-1 shows the extent to which water flows can vary from year to year and drive large swings in financial returns in any given year (or longer), even if the long-term trend is mean-reverting.

The financial implications of the inflows shown in Figure 2-1 are portrayed in MIPUG/MH I-35(a), as shown in Figure 2-2 below.

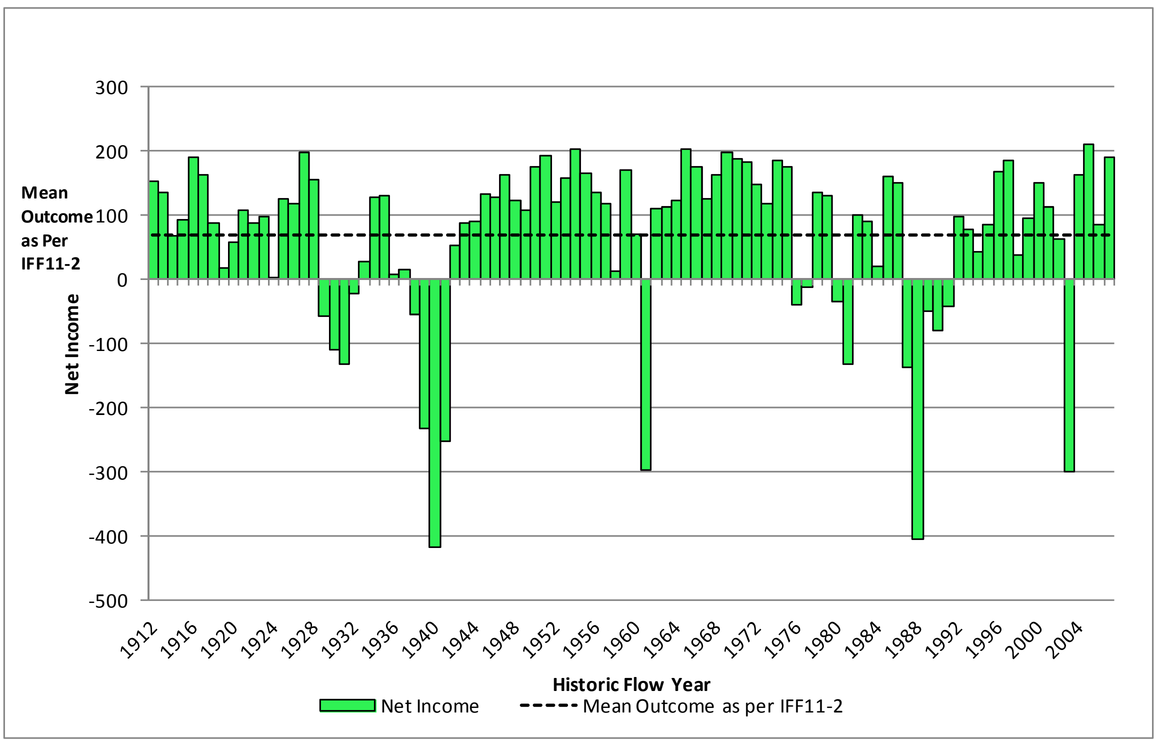
[22] Figure 9.6.1 Historical Water Supply from Tab 9: Energy Supply from Hydro's 2012 GRA, Page 22.

Figure 2-2: Financial Implications of Flow Variability

Flow Year	Annual System Inflow	MH Hydraulic Energy	Net Revenue	Variation of Net Revenue from Average
	Kcfs	(GWh/yr)	(M $Cdn)	(M $Cdn)
1912	112	33311	163	85
1913	118	32586	145	67
1914	98	29436	78	0
1915	105	30489	104	26
1916	136	35587	199	121
1917	118	33818	172	94
1918	105	30401	99	21
1919	98	27720	28	-50
1920	103	29204	67	-11
1921	113	31050	117	39
1922	105	30392	98	20
1923	111	30721	108	30
1924	98	27261	12	-66
1925	119	31994	135	57
1926	111	31450	127	48
1927	154	37324	208	130
1928	114	33612	165	86
1929	87	25626	-46	-124
1930	89	24518	-100	-178
1931	87	24074	-121	-199
1932	95	26473	-12	-90
1933	101	27936	39	-39
1934	118	32074	138	60
1935	117	32275	141	63
1936	96	27498	18	-61
1937	98	27794	26	-52
1938	89	25634	-44	-122
1939	79	22487	-223	-301
1940	55	20042	-406	-484
1941	92	22218	-242	-320
1942	101	29103	63	-15
1943	108	30218	97	18
1944	106	30400	101	23
1945	119	32241	143	65
1946	113	32110	139	60
1947	125	34004	173	95
1948	113	32939	134	56
1949	116	31104	117	38
1950	144	35273	184	106
1951	132	36093	202	124
1952	106	31902	131	53
1953	124	33367	168	90
1954	142	37174	213	135
1955	132	34986	174	95
1956	118	32997	144	66
1957	113	31665	128	50
1958	95	27565	24	-54
1959	137	34268	179	101
1960	102	30318	81	3
1961	75	21612	-288	-366
1962	118	31334	121	43
1963	110	31345	123	45
1964	113	31738	133	55
1965	156	36961	212	134
1966	151	35673	184	106
1967	115	32846	136	58
1968	133	33801	172	94
1969	147	37347	208	130
1970	144	36113	198	120
1971	140	35744	192	114
1972	125	34240	158	79
1973	116	31592	129	51
1974	164	36449	195	117
1975	139	35487	186	108
1976	94	26961	-29	-107
1977	100	26793	-1	-79
1978	121	32405	146	68
1979	136	33443	140	61
1980	93	26105	-24	-102
1981	86	24082	-121	-199
1982	115	30779	110	32
1983	111	30740	100	22
1984	99	27876	30	-48
1985	137	33909	171	93
1986	131	34115	161	83
1987	83	23940	-127	-206
1988	72	20209	-395	-473
1989	90	25839	-39	-117
1990	86	25187	-70	-148
1991	91	26074	-31	-109
1992	115	30747	107	29
1993	106	29974	88	10
1994	102	28723	52	-26
1995	104	30239	96	18
1996	142	34890	177	99
1997	153	36080	196	117
1998	106	29969	49	-29
1999	112	30608	105	27
2000	126	33153	161	83
2001	129	32678	124	46
2002	107	29637	73	-5
2003	74	21460	-290	-368
2004	129	33671	173	95
2005	187	37846	221	142
2006	114	32052	96	18
2007	150	36202	201	123
Average	**114**	**30744**	**78.12**	**0**

The values shown in Figure 2-2 reflect the financial impact on a given year from the flow variation shown in Figure 2-1; that is, 'if the historical water flows repeat themselves with today's system and today's prices, and given Hydro ability to store water and make market transactions, what would be the financial implications?'. The column noted as "Net Revenue" is a summary of a combination of flow related impacts as described in the response to MIPUG/MH I-35(a), but in simple terms serves as a rough approximation of the net income that would arise in fiscal 2013/14 with the noted flow event[23]. Over the 96 flow year history, this chart represents a net increase to reserves over the long-term, but with periods where reserves are drawn down substantially due to drought. For example, during a repeat of the 1937 to 1941 five year drought flow sequence, reserves would be drawn down by $939 million[24] (not including compounding interest impacts), as shown in the following Figure 2-3.

Figure 2-3: Variation of Flow Related to Net Income for 2013/14 ($ Millions)



It is important that Hydro have reserves to at least the level of the net loss arising during severe droughts shown in Figure 2-3 to sufficiently protect ratepayers. Comparable numbers for the 1987-1991 period is a drawdown of $712 million. These are the worst two instances in the historic record shown.

[23] The mean "Net Revenue" of all flow sequences, considering the noted factors, is $78 million. The forecast net income in 2013/14 is $68 million as seen in IFF11-2 Page 31, meaning that the sum of all non-flow related revenues and costs is net negative $10 million. A more precise approximation of net income for the fiscal year means that this net negative $10 million from non-flow related items.

[24] The summation of the values shown as Net Revenue for those five years, plus $10 million/year for non-flow related transaction.

The main rationale for targeting a particular capital structure or reserve level is to have ratepayers contribute, through today's rates, to protect themselves from future rate shocks, through appropriate reserves for rate stabilization. Regardless as to how such amounts are recorded in audited statements (e.g., as shareholder's equity), the clear purposes of the reserves is linked to the ratepayer risks (in aggregate), the largest of which remains major infrastructure failure and drought[25]. Much like an insurance concept, the risks that are large, relatively sudden, and acute (such as droughts), require appropriate reserves – otherwise when the event happens, rates would have increase rather quickly and markedly to the detriment of ratepayers. Risks that are smaller, or longer-term, or have natural offsets or hedges, do not require reserve backing to the same degree, as, in the event they arise, they can be addressed by a long-term incremental adjustment to rates.

Hydro has not presented the facts regarding reserves in any way inconsistent with this theoretical framework, such as in PUB/MH I-33: "Hydro also requires retained earnings to cover numerous other risks that it is exposed to. As such, it is important that Manitoba Hydro continue to maintain an adequate level of retained earnings and that rates be raised gradually even during years of exceptional water flows in order to ensure that customers continue to have stable rates in the future."

In contrast, Hydro's gas operations, being a largely "flow through" operation, present very few such risks that are suitably addressed by reserves. Consequently, that operation can reasonably continue with very low annual net income (more appropriately thought of as "contribution to reserves") in any given year, and low total reserve levels.

[25] See, for example, CAC/MH II-38(a).

3.0 OVERVIEW OF APPLICATION

Manitoba Hydro's 2012/13 & 2013/14 General Rate Application requests a lengthy number of approvals from the PUB. Rather than adopt the $12 million/year rate decrease (1%)[26] that was directed by the Public Utilities Board in Order 5/12, Hydro's IFF11 indicated a proposal to cancel the 1% rate reduction, and implement new rate increases for 2 year increases (2012/13 and 2013/14) of approximately $90 million/year (7%), which has since been amended to approximately $105 million/year (8%) by IFF11-2.

The rate requests being sought which are addressed in this submission are as follows:

Current Test Year Rates

- **April 1, 2012:** Final approval of Orders 32/12 and 34/12 approving a 2.0% across-the-board interim rate increase effective April 1, 2012. The effect of this increase is approximately $25.4 million annually[27] based on 2012/13 load forecasts.
- **September 1, 2012:** Approval of a 2.5% across-the-board rate increase effective September 1, 2012, which has to date been largely implemented on an interim basis by Orders 116/12 and 117/12 (with the notable exception of $0.7 million of annualized residential and small non-demand fixed monthly charges[28], which have yet to be implemented). The annualized impact of this increase is approximately $32.0 million based on 2013/14 loads, of which $31.3 million has been approved on an interim basis[29].
- **April 1, 2013:** Approval of a 3.5% increase in overall revenue effective April 1, 2013. Pursuant to a letter dated November 7, 2012, this is now proposed to be implemented on an across-the-board basis pending the Cost of Service and Rate Design review. This increase is proposed to be collected largely by way of increases to energy rates (>3.5%) with most demand charges and basic monthly charges being unaffected. In the GRA filing, Hydro estimated this would be sufficient to generate additional revenues of $47.2 million in 2013/14[30].

Revision to Past Rates

- **1% Roll-Back:** Board Order 5/12 approved <u>final</u> rates for 2010/11 and 2011/12 (subsequently confirmed by the Board in rejecting Hydro's Review and Variance Application in Orders 19/12 and 21/12). Those final rates have not been implemented to date. Instead Hydro has charged rates

[26] Awarded for all domestic rate classes (except Area and Roadway Lighting, which was not included in the initial interim rate increase).
[27] The 3.5% increases was estimated in Appendix 6 of the April 1, 2012 Interim Rate Application filing at $44.4 million.
[28] Per Manitoba Hydro letter to the PUB dated August 31, 2012, and Appendix 27.
[29] GAC/MH II-31(a).
[30] Appendix 10.12: Proof of Revenue. Updated on November 7, 2012.

since April 1, 2010 that are approximately 1% higher than provided for in Board Order 5/12 and, pursuant to PUB Order, was to track the ongoing difference to a deferral account (the "1% roll-back"). Hydro now seeks a revision to the terms of the Order 5/12 rates so as to revert to the higher rates originally approved for 2010/11 and 2011/12 on an interim basis in Orders 30/10 and 40/11, and to include in current year revenues now the amounts in that deferral account[31]. The net effect of this request is a failure to implement approximately $12 million annually in rate revenue decreases. Additionally, it allows Hydro to take into income ratepayer funds held in the deferral account which total some $25.3 million to June 2012 and increasing by $3 million per financial quarter.

Other Matters

- **Curtailable Rate Program:** Hydro seeks the Board's approval to amend the Terms and Conditions of the Curtailable Rate Program ("CRP") to eliminate "Option C" and to lower the cap setting out the maximum participation in "Option A".

The Hydro requests related to customer-class specific "differentiated" rate increases, Time-of-Use rates and proposed changes to the industrial rate demand calculations are not addressed here, pending a subsequent proceeding as directed by the Board.

Hydro's filing provides information on net income and financial position for 2011/12, and indicates the company has reached over $2.45 billion in retained earnings, the highest level of retained earnings in the corporation's history[32]. Hydro now has a Debt:Equity ratio which exceeds the company's target of 75:25[33]. At the same time, Hydro's filing also indicates what appears to be a material reduction in long-term forecast financial performance, with the Debt:Equity eroding to 81:19 by as early as 2013/14 and forecast to remain 4-6 percentage points worse through the 20 year forecast horizon than was forecast in IFF 10-2 at the previous GRA[34].

Manitoba Hydro indicates at Tab 2 that the basis for the rate increases is to avoid a net loss in light of "lower prices in export markets and higher power purchases"[35] and that failure to implement the increases "would have serious consequences on the credit rating of the Province and Manitoba Hydro"[36]. Hydro also provides an updated International Financial Reporting Standards (IFRS) transition plan at

[31] In Order 30/10 the PUB approved an interim rate increase of 2.9% effective April 1, 2010. In Order 40/11, the PUB approved an interim rate increase of 2.0% effective April 1, 2011. In Order 5/12, the PUB approved final rates of 1.9% effective April 2, 2010 and 2.0% effective April 1, 2011.

[32] Tab 2: Summary and Reasons for Application. Page 1.

[33] Manitoba Hydro 2012/13 and 2013/14 GRA, Appendix 5.8, Manitoba Hydro-Electric Board Annual Report Year Ended March 31, 2012 , Page. 6.

[34] PUB/MH I-30(a).

[35] Tab 2. Page 1 lines 20-21.

[36] Tab 2. Page 3 lines 28-29.

Appendix 5.5, which notes material upward pressure on the annual Income Statement from changes in the timing with which Manitoba Hydro will recognize certain costs (largely capital-related).

IFF11-2, which is the basis for the Application, reflects an atypical approach to forecasting[37]. In particular, the first major forecast year of the IFF is normally forecast using long-term median inflows. In the case of IFF11-2, the forecast instead reflect the "near record dry conditions leading up to the preparation of the IFF which strongly indicated that spring runoff would be well below normal"[38] in April 2012. In short, IFF11-2 is a drought-based IFF for the initial years. Net extraprovincial revenues for 2012/13 are apparently projected to be $32 million less in IFF11-2 than in IFF11 as a result of this lower forecast inflow[39]. Since the preparation of IFF11-2, Hydro indicated that they have experienced "above average inflows from June to August leading to above average hydraulic generation"[40]. This increased hydraulic performance has not been incorporated into GRA forecasts.

Other items of note contained in Manitoba Hydro's Application include:

- **Capital Expenditures:** The Capital Expenditure Forecast for 2011 (CEF11)[41] dated November 2011 indicates forecast capital expenditures for the period through 2021/22 of $19.4 billion. Major new generation and transmission projects make up $14.1 billion of that forecast[42].
- **Power Resource Plan:** The external-use 2011/12 Power Resource Plan (Attachment 3 to September 1, 2012 rate increase supporting materials) indicates Hydro is now planning in its Base Case IFF to be pursuing the "Sales Package" which is the largest export package identified in that document. Alternative plans now include a "250 MW Interconnection" package which remains an export focused development plan, but at a smaller scale Wisconsin Power sale, and a "No New Interconnection" plan which now has combined cycle gas as the first resource, and no new hydro until 2027/28 (Conawapa). This plan is now 15 months old, and no new Power Resource Plan has been provided. The 2011/12 Power Resource Plan now shows sustained system surpluses exceeding 1250 GW.h (the dependable output of Wuskwatim) through 2018/19.
- **Drought Costs:** Hydro's estimated cost of a 5 year drought has dropped dramatically since the previous GRA. As set out at Tab 9, page 25, the reduction in export market prices and in natural gas fuel costs means that the impact of a 5 year drought, with compounded interest, is now $1.6 billion or 33% below the previous estimate of $2.4 billion[43]. Further, projected net income over

[37] MIPUG/MH-1-43(b).
[38] MIPUG/MH-1-43(c).
[39] Manitoba Hydro 2012/13 and 2013/14 GRA, Appendix 4.2. Page 3.
[40] PUB/MH II-20(a).
[41] Appendix 6.1.
[42] Manitoba Hydro 2012/13 and 2013/14 GRA, Tab 6. Page 3.
[43] Tab 8: Energy Supply from 2010 GRA. Page 19.

this period totals approximately $0.6 billion[44], so the total net loss in a repeat of the worst 5 year drought on record is now down to $1.0 billion.

- **Depreciation Study:** Hydro has provided a series of updated depreciation studies, as described in Appendix 5.7, which portray a substantially longer life for many assets than was previously assumed. As a result, Hydro concludes that the annual depreciation rate on many of its assets should be lowered, and calculates that there is a $550 million past over-depreciation[45] of assets as of March 31, 2010. Subsequent to this conclusion, Hydro makes two further conclusions. First, that the collection of the costs of "future removal" of assets should be eliminated from ongoing depreciation and instead become a cost item to be dealt with when the cost is incurred at the time of removal. This change serves to lower depreciation rates and increase the calculated present day over-depreciation. Second, Hydro proposes to adopt a much more aggressive approach to calculating grouped depreciation starting in 2013/14, the ELG method. This ELG approach serves to raise depreciation rates and decrease the calculated present day over-depreciation. The end result of these two changes is a slight reduction in the rate of depreciation, and a slight increase in calculated over-depreciation, now up to $600 million as of implementation of the proposed approaches at April 1, 2013[46].

- **Industrial Load Forecasts:** Hydro's load forecasts show a new marked decline in forecast industrial growth. In particular MIPUG/MH I-40(a) at pages 7-8 shows that in the latest load forecast, by about 2017, industrial (>100 kV) loads are expected to be about 1-2 TW.h lower than assumed in the recent load forecasts (since 2008), with this reduction sustained throughout the forecast period. Industrial loads today are already 1.5 TW.h lower than they had been expected to be based on the 2008 load forecast.

[44] IFF11-2. Consolidated Projected Operating Statement. Sum of Net Income 2014 – 2018. Page 19.
[45] MIPUG/MH I-15(e).
[46] MIPUG/MH I-15(h).

4.0 COMMENTS ON HYDRO'S FINANCIAL FORECASTS

Hydro's application attempts to portray the need for annual rate increases over the test years, as well as sustained rate increases above inflation over the coming decade and beyond, in order to satisfy three main financial objectives:

1) Provide for operating costs in each year;
2) Cover the costs of capital allocated to each year, in the form of depreciation and interest expenses; and
3) Ensure the Corporation is able to meet its short and long-term financial targets.

As compared to a typical regulatory review, Hydro's IFF11-2 and the rate requirements are complicated by three major factors:

- **Export Price Decline:** This GRA reflects a substantial reduction in opportunity export prices, and natural gas fuel prices, leading to reduced export revenues but also lower overall costs for fuel and for serving extreme droughts which form part of the IFF "averaging" calculations. In the test years, this price impact since IFF09-1 is estimated at approximately $250 million[47], with an offsetting average savings of $100 million in fuel costs[48]. A further $60 million of the change arises in the form of lower net income[49], which is consistent with a somewhat reduced need for building reserves in the face of much less exposure to expensive drought events. Of the remaining $90 million net impact[50], approximately $70 million is saved in the form of lower interest rates than those assumed in IFF09-1[51] plus a series of other small changes. In short, the export price declines in the test years are largely addressed by other offsetting factors within Hydro's cost structure as compared to earlier assumptions. Also of note is that the decline in export prices has not affected dependable sales, instead primarily affecting opportunity sales, as shown in Hydro's Figure 9.5.2 in Tab 9[52].
- **Accounting Changes to Advance The Timing For Recognition of Largely Capital-Related Costs:** Hydro's selection of proposed accounting approaches for Operating, Maintenance and Administration (OM&A) and depreciation result in costs in the test years that

[47] IFF09-1 shows extraprovincial revenue for 2013/14 at $615 million; IFF11-2 shows $363 million.
[48] IFF09-1 shows fuel and purchased power for 2013/14 at $260 million; IFF11-2 shows $158 million.
[49] IFF09-1 shows net income for 2013/14 at $125 million; IFF11-2 shows $68 million.
[50] ($250 million less $100 million in fuel costs less $60 million net income).
[51] IFF09-1 shows interest for 2013/14 at $527 million; IFF11-2 shows $452 million.
[52] Tab 9. Page 14.

approximate $130 million/year higher[53] than under past practice, and a further one-time write-off to retained earnings of approximately $341 million[54], a full 2.0 percentage points adverse impact on the calculated electric operations Debt:Equity ratio[55].

- **Ongoing Investment in "Work in Progress" Towards the Power Resource Plan Projects, and other assets not yet in service:** By 2013/14, the end of the current test years, there will be approximately $1.4 billion of investment in Keeyask and Conawapa[56], driving a further decline of 2.4 percentage points of the electric Debt:Equity ratio. A further $0.9 billion of debt (1.8 percentage point decline on the Debt:Equity ratio) is related to the Bipole III project[57], which similarly will not be serving ratepayers until approximately 2017/18.

In short, for the actual test years in question, the current GRA filing is challenged to reflect the fair financial requirements specific to the two test years in a way that is representative of assets actually in service and serving ratepayers. Instead, unprecedented financial and capital transactions overwhelm the longer-term financial forecasts. There is no "status quo" utility portrayed in the GRA materials. The IFF and rate proposals are presented as being inseparable from 15 sustained years of massive capital investment including projects advanced for export purposes, major new export sale commitments, and sustained rate increases above inflation.

In practice, the large future capital program serves as a distraction from the scale of changes being proposed by Hydro in the immediate future that serve to burden today's ratepayers with a substantial shift of costs that had previously been considered to be relevant to provision of service in the future, and not today. The rate requirements in the current GRA test years are in fact driven more by a combination of cost shifts (moreso than cost increases) as expenses that are related to future construction and future use of assets are instead proposed to be included in the costs that Hydro seeks to recover from today's ratepayers.

This section of the testimony addresses:

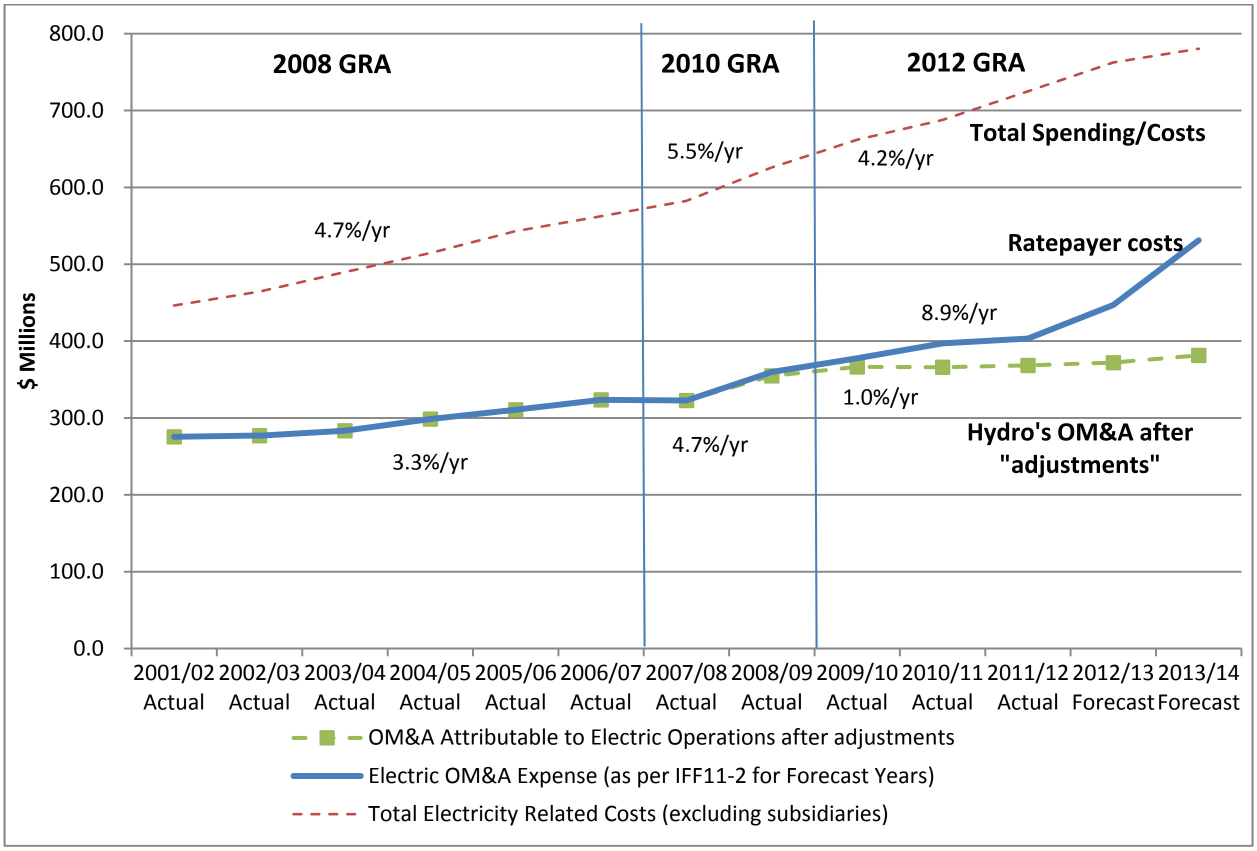
- Hydro's overall level of costs, particularly OM&A costs;
- Hydro's proposals with respect to the timing for recognition of costs; and
- Changes to Hydro performance towards its financial targets and reserves.

[53] PUB/MH I-42. Schedule A (Page 2) in 2013/14 calculation as follows: $32 million ELG + $62 million CGAAP Changes + $36 million Admin and General IFRS Changes.
[54] Per PUB/MH I-42, Page 4, at $288 million, excluding the $53 million related to Net Salvage Depreciation.
[55] Per PUB/MH I-30(c). 2013/14 as forecast by Hydro at 0.81. Including additional $341 million in Retained Earnings drops this ratio to 0.79.
[56] CEF11 Total Project Spending excluding all remaining spending after 2013/14. Page 2.
[57] CEF11 Total Bi-Pole III spending (Transmission Line, Converter Stations and Collector Lines) excluding all remaining spending after 2013/14. Page 2.

4.1 LEVEL OF COSTS

Hydro's costs in the current GRA filing continue to show sustained growth, as shown by the "Total Spending/Costs" line in Figure 4-1, and further discussed in Attachment B.

Figure 4-1: Hydro Total Spending/Costs and Ratepayer Costs 2001/02 to 2013/14[58]



	2001/02 Actual	2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
OM&A Attributable to Electric Operations after Adjustments	275.4	277.0	283.5	298.7	310.7	323.6	322.8	354.7	366.4	366.1	368.4	372.0	381.4
Electric OM&A (as per IFF11-2 for Forecast Years)	275.4	277.0	283.5	298.7	310.7	323.6	322.8	359.7	377.6	397.0	403.4	446.9	531.1
Total Electricity Related Costs (excluding subsidiaries)	446.2	464.3	489.9	514.5	543.1	562.3	582.3	626.0	662.0	687.8	725.0	762.5	780.3

The "Total Spending/Costs" line in Figure 4-1 shows the growth in "top line" costs (not including purchases directly charged to capital), prior to allocations to the capital program. The long-term trends remain above 4% annually, somewhat below the 5.5% shown in the actual years leading up to the 2010 GRA. Hydro further indicates that the forecast costs also do not include an estimated $50 million/year

[58] Data from 2001/02 to 2006/07 numbers from Appendix 12.11: O&A Expenses; Variance from 2008 GRA, Page 2; 2007/08 to 2008/09 numbers from Appendix 4.4 of 2010 GRA, Page 14; 2009/10 to 2013/14 numbers from Appendix 5.6 of 2012 GRA, Page 7; Adjustments from PUB/MH I-42 of 2012 GRA.

that will be required for distribution system OM&A and capital (that is presently unbudgeted) to "upgrade aging distribution" and "avoid large-scale and long-duration outages"[59].

Figure 4-1 also highlights the ratepayer costs in a given year (those costs not capitalized) shown as the solid line, highlighting the significant implications for ratepayers arising from new proposed changes to cost allocation and recognition changes, as addressed in following sections of this submission. Hydro's "adjusted" OM&A portrays the values Hydro focuses on in calculating its own achievements towards Corporate Strategic Plan targets (such as OM&A cost/customer[60]). In particular, this calculation is adjusted to remove one-time reallocations that serve to increase costs, such as the proposed inclusion of PowerSmart activities in OM&A. At the same time one-time reallocations that serve to decrease costs, such as the elimination of leases due to the move to the new head office building (which is matched by higher attendant new costs for depreciation and interest which show up in other categories) are not "adjusted" out of the values[61].

Staffing levels also continue to increase. Board Order 5/12 discusses Labour and Benefits as part of OM&A costs and the capitalization of these costs coming out of the 2010/12 General Rate Application:

> A major driver in the increase in O&A expense is due to increased staffing levels which are projected to grow from 5,769 Equivalent Full Time (EFTs) in 2004 to 6,669 EFTs [in 2010/11 and 2011/12], an increase of 900 EFTs or over 15%[62].

For the current filing, EFTs are projected to further increase to 6,842 in 2012/13[63]. Figure 4-2 below shows the comparison of capitalized versus uncapitalized EFTs (including standard-time and overtime hours) for actual and forecast years.

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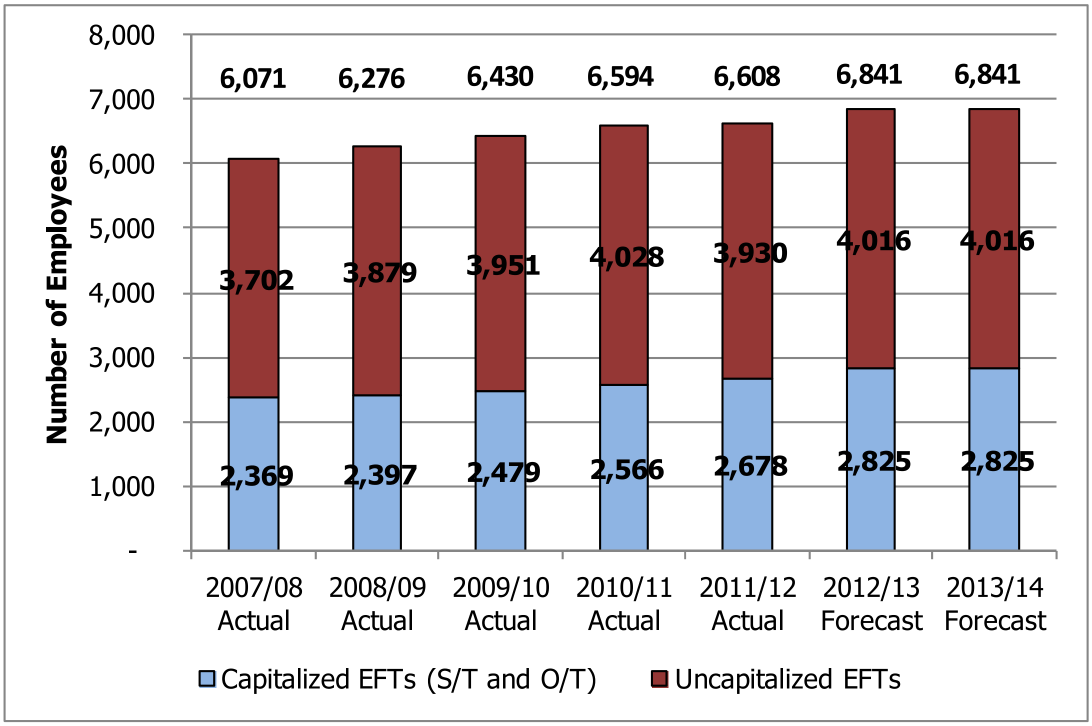
[59] Appendix 5.6, Page 3.
[60] Appendix 5.6, Page 1.
[61] Appendix 5.6, Page 10, lines 21-24.
[62] Manitoba PUB Board Order 5/12. P. 91 (January 17, 2012).
[63] Forecast EFTs from Appendix 5.6: Operating, Maintenance and Administration (p. 12).

Figure 4-2: Capitalized and Uncapitalized EFTs 2007/08 to 2013/14[64]



It is also important to note that the 2013/14 value for capitalized employees in Figure 4-2 appears to be prior to the International Financial Reporting Standards (IFRS) related changes to capitalization. If these changes are included, the average number of capitalized employees in 2013/14 would be considerably lower than the 2,825 shown above, potentially as low as 2,189 employees[65].

Understanding the growth in staffing is difficult, as Hydro has provided inconsistent data in relation to the staffing levels and vacancy rates. In MIPUG/MH I-29(d) Manitoba Hydro calculated the vacancy rate used for the forecast years, using a number for "Total Positions" (6,882) that does not reconcile to any other number filed in the Application, and further appears to note that only 6,456 are "Budgeted Positions" which appears entirely inconsistent with the data from PUB/MH I-38(e)[66] used in Figure 4-2.

[64] PUB/MH I-38(e) from 2012/14 GRA.

[65] This is based on the fact that 2,825 employees capitalized arises from the 41% capitalization ratio shown in PUB/MH I-38(e); however, after accounting changes this ratio drops to 32%, based on a further $71.6 million of costs no longer being capitalized in 2013/14 as per MIPUG/MH I-9(a).

[66] In MIPUG/MH II-15(a), MIPUG asked for further calculations in an attempt to reconcile EFTs to which Manitoba Hydro restated the same number and same approach without any explanation to where the 6,882 EFT number came from in this Application.

One item of particular note is in MIPUG/MH I-29(h), where Hydro shows that they have consistently under forecast the vacancy rate compared to actuals for all years since 2007/08 (average budget vacancy rate of 5.8%, average actual vacancy rate of 8.0%)[67]. The actual average vacancy rate is consistent with the expected performance during a period of hiring freezes[68] when vacancies would be expected to be higher than during typical periods. If the 8% vacancy rate is maintained in practice (instead of the 6.2% rate currently being forecast) total staffing levels will remain flat through the 2010/11 to 2013/14 period.

Hydro's performance on cost control, on a simple incremental basis, remains typical if not slightly below, the increases over the past number of years. In short, the current cost control initiatives appear to have had at most a small effect on the rate of growth. With specific reference to the memorandum issued by Hydro's President in 2009 and 2010[69], concerns were expressed with Hydro's cost control performance, as follows:

- "Over the past five years, travel expense has increased at an average annual rate of 6.6% per year".
- On wages, salaries and benefits: "Over the past five years, this component of operating expense increased at an average annual rate of 5.0% per year including a 6.2% increase over the past year. EFTs peaked at an all-time high of 6620 during 2009/10".
- "Overtime costs have grown at a very significant average rate of 8.3% per year over the past five years. In 2009/10, overtime costs exceeded $50 million, an increase of 9.6% over the previous year" (Exhibit MH-112).
- The memorandum also noted a potential freeze on executive and management salaries as of December 31, 2010. As noted at transcript page 5555 from the 2010 GRA this freeze was not implemented.

While it can be challenging to directly compare two utilities, a recent aggressive operating cost review was conducted on BC Hydro by a committee of three Deputy Ministers, which concluded that significant savings were possible in that utility. One excerpt of note from their review is as follows:

> It is the panel's opinion that, due to the regulatory environment and the corresponding corporate culture in BC Hydro, "being the best" and the resulting desire to have the gold standard is not necessarily for lowest cost or greatest value for money. The corporation

[67] This forecast methodology appears to be different than the approach used to forecast vacancies at the time of the 2010 GRA where Hydro stated the following: "As part of the budget process a vacancy factor is calculated for each year based on historical data as well as known or expected turnover for the upcoming forecast years. Consideration is given for expected retirements, as well as time allotment for the hiring process" in CAC/MSOS I-15(b) from 2010/12 GRA.
[68] MIPUG/MH I-29(f).
[69] Exhibits MH-112 and MH-124 from the 2010 GRA.

is focussed on justifying incremental rate increases and associated costs rather than employing a zero-based operating budget development methodology to understand its underlying cost structure. Understanding the base costs will provide BC Hydro greater opportunity to challenge the current costs and improve overall cost effectiveness[70].

In the context of Hydro's OM&A cost presentation, the criticism of "justifying incremental rate increases and associated costs"[71] rather than focusing on the underlying cost structure is particularly noted. As an example, the BC review specifically concluded that BC Hydro should target "a more reasonable staffing level" of 4,800 employees[72] (in contrast to the current 5,900[73]), rather than simply comparing the change in employee numbers from one year to the next to determine reasonableness.

4.2 RECOGNITION OF COSTS

In respect of accounting changes that alter the timing of recognition of costs, the current GRA presents a lengthy list of changes, the most notable being:

- **Elimination of Full Cost Accounting principles from calculation of overheads to be capitalized[74]:** This change reflects a gradual implementation, with the advancement of cost recognition starting in 2009/10 ($13 million/year), but ramping up considerably through 2010/11 ($33 million/year) and through 2013/14 ($62 million/year)[75].
- **Further narrowing of capitalization of overheads for "Admin and General":** Timed as part of IFRS implementation (assumed at 2013/14 in IFF11-2, since confirmed that will not occur until 2014/15[76]). This item drives an advancement of cost recognition of $36 million/year[77].
- **Elimination of Future Removal or Net Salvage costs from depreciation:** This item is proposed to match the implementation of IFRS; however, it reflects adoption of an accounting approach used by many utilities in past decades, and further expanded in the early 2000s well before IFRS was initiated. The change yields a decrease in net costs of $55 million/year[78].
- **Adoption of the more aggressive Equal Life Group (ELG) method of depreciation**: Timed to match implementation of IFRS, this change advances recognition of capital-related

[70] Review of BC Hydro, June 2011, Page 2, at: http://www.newsroom.gov.bc.ca/downloads/bchydroreview.pdf.
[71] Emphasis added.
[72] Review of BC Hydro, Page 6.
[73] Review of BC Hydro, Page 23.
[74] PUB/MH I-61(a).
[75] PUB/MH I-42 Schedule B. Line: 'Annual Change to OM&A'.
[76] MIPUG/MH II-1(a).
[77] PUB/MH I-42 Schedule A. IFRS Changes to OM&A Line: 'Admin and General'.
[78] PUB/MH I-42 Schedule A Cont'd. IFRS Changes to Depreciation Expense: Line 'Removal of Net Salvage from depreciation rates'.

costs by $32 million/year and growing[79]. This approach is more aggressive in that for the same asset more of the costs are depreciated in the early years of the asset's life.

One further change which affects largely the balance sheet and not the net income is as follows:

- **Elimination of Power Smart/rate-regulated assets from retained earnings, and expensing all Demand Side Management (DSM) activities in future:** Timed to match the proposed implementation of IFRS. This item has limited impact on net income, but a material impact on retained earnings.

Outside of the elimination of future removal costs from depreciation, which is a reasonable approach for rate setting regardless as to IFRS implementation, the remaining items each reflect an advancement or an early discharge of costs that were previously recognized when the economic benefits from the spending were realized (i.e., in the future). Specific details on the proposed changes are addressed in the following section.

At a general level, however, Hydro justifies a considerable range of changes on the implementation of IFRS or other accounting changes (CGAAP). However, Hydro's subsequent IR filings clarify that these items are not in fact driven by proscribed accounting changes:

- The elimination of Full Cost Accounting is included under the heading "CGAAP Changes" in PUB/MH I-42 Schedule A, but later at PUB/MH I-79(a) Hydro clarifies that: "The full cost accounting approach has been used in the utility industry for decades and is permissible under CGAAP[80].
- The adoption of the ELG method of depreciation is presented in PUB/MH I-42 as being an "IFRS Change" and described in the Application (Appendix 5.7) as an IFRS compliant depreciation practice specifically noting that "Manitoba Hydro will implement IFRS compliant depreciation rates effective April 1, 2013 which will include a change in depreciation methodology to the Equal Life Group (ELG) and the removal of asset retirement costs from depreciation rates"[81]. However, in CAC/MH I-47(a) Hydro clarifies that the change from the existing ASL method to ELG is not required by IFRS, as follows: "IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS"[82].

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[79] PUB/MH I-42 Schedule A Cont'd. IFRS Changes to Depreciation Expense Line: 'Change to Equal Life Group Depreciation method'.
[80] PUB/MH I-79(a).
[81] Appendix 5.7 Page 1.
[82] CAC/MH I-47(a) Page 1.

- Hydro portrays the impact of IFRS on the basis that "rate-regulated accounting" will not be allowed. However, the very reason for the extended delays in implementing IFRS for utilities (further delayed by one-year as of a decision dated September 5-6, 2012[83]) is due to an active and as-yet unresolved debate about the recognition of rate-regulated activities under IFRS or comparable outcomes. Further, when asked to provide an IFF that shows the impacts of continuing rate regulated accounting (PUB/MH I-78(b)), Hydro is excessively narrow in its definition of "rate regulated accounting" as encompassing only the Power Smart and related write-offs, and failing to consider the possibility that the rate regulator may also impose a broader definition of rate-regulatory accounting to include other items that meet the normal test of "sufficient assurance of future recoverability" [84] such as potentially a more complete capitalization of overheads.

Further, Hydro provides no alternatives for consideration regarding mitigating the impacts of these changes. In the 2010 GRA, Hydro discussed this problem at transcript pages 4446 to 4448 and provided examples of solutions that should be pursued, such as a "supplementary schedule" which forms the basis for rate setting separate from IFRS financial statements, or alternatively electing an accounting approach that leads to a qualified audit which was described as being "…not the end of the world…"[85]. Hydro's response to CAC/MH I-36(g) also notes that for a number of Canadian jurisdictions (including BC, Alberta, Ontario, Newfoundland) the regulators have adopted measures to ensure the more onerous effects of IFRS accounting do not become driving factors in setting rates, and notes that many utilities have in fact rejected IFRS entirely where the option exists to use US GAAP which, permits regulatory accounting (unfortunately the approach used by these other utilities is linked to their traded securities, which is not an option available to Manitoba Hydro). In the case of BC Hydro, who similar to Manitoba Hydro cannot use securities law to justify the use of US GAAP, a direction was sought from the Province that the utility is to apply a modified IFRS, known as the "Prescribed Standards"[86] that permits the utility to continue to record items as assets that the regulator has or is likely to permit to be recovered in future rates. Instead, in the current filing, no such alternatives are identified or pursued by Manitoba Hydro.

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[83] http://www.frascanada.ca/accounting-standards-board/meetings/decision-summaries/2012/item67809.aspx.

[84] As is discussed in the CAMPUT Letter to the IFRS Committee re: Agenda Paper 7A: Project Plan for Agenda Request on Rate Regulated Activities (October 27, 2008). http://www.auc.ab.ca/items-of-interest/ifrs/Documents/IFRS/2008-10-27%20IFRIC%20Letter.pdf.

[85] Tr. 4448; 2010 GRA. (March 21, 2011).

[86] BC Hydro First Quarter Report – Fiscal 2013. Page 2 http://www.bchydro.com/etc/medialib/internet/documents/about/company_information/reports/f2013_q1_report.Par.0001.File.F2013-Q1-Report.pdf.

4.2.1 Capitalization of Overheads

Hydro's GRA sets out proposed adjustments to markedly reduce the scale of costs being capitalized as "overheads" (the direct and indirect costs of supporting the capital program). These changes, which began as early as 2008/09, are described in PUB/MH I-79(a). In particular Hydro cites that its previous approach of "full cost accounting" was and continues to be permitted under CGAAP. Despite these approaches being permitted under CGAAP, Hydro began reducing the magnitude of costs that it capitalized noting that the revised more narrow approach was "also permissible under CGAAP"[87]. Hydro then goes on to explain that its earlier full cost accounting approaches, and its ongoing revisions through 2009-2013 are not permissible under IFRS.

The move to shift costs that were previously classified as capital-related into the OM&A costs of the current year conflicts with Hydro's changing cost profile, which if anything suggests an increasing portion of the Corporate cost structure is in fact being driven by capital. In particular, the significant increases in the scale of the capital program is a part of the justification behind increases in staffing levels, cited in Board Order 5/12 as being a growth from 5,769 EFTs in 2004 to 6,669 EFTs, and further in this GRA to 6,842 EFTs (an almost 19% increase). The Board earlier noted:

> This increase in staffing levels was defended by MH as due to increased work requirements. The staffing level increases are due in part to the capital expansion plans of the Corporation, as a large number of those hired were to work on capital projects[88].

Hydro's filing does not provide any attempted rationale to suggest that: (a) the previous full cost accounting approach to capitalization is in any way an inferior approach for rate making and should not be continued; or (b) the change to shift $130 million/year[89] of capital-related costs into current day rates is in any way more representative of the changing cost structure at Hydro than the previous approach.

Instead, the evidence suggests that despite adding over 1,000 EFTs since 2004[90], with a large part of this complement being justified on the basis of the growing capital program, in practice Hydro is effectively capitalizing none of these EFT additions.

4.2.2 Depreciation

Manitoba Hydro has filed at Appendix 5.7 two updated Depreciation Studies for depreciable assets in service as of March 31, 2010, prepared by the consulting firm Gannett Fleming. The intent of the studies

[87] PUB/MH I-79(a).
[88] PUB Order 5/12, Page 92.
[89] Mentioned on Pages 4-7 and 4-8 from PUB/MH I-42: $32 million ELG change to Depreciation Expense plus $62 CGAAP Changes to OM&A plus $36 million IFRS Admin & General Changes to OM&A per year starting in 2013/14.
[90] 6,842 Forecast EFTs less 5,769 EFTs equals 1,073 EFTs.

is to determine the annual depreciation accrual rates and amounts for financial reporting purposes applicable to the original cost of plant as of March 31, 2010 (using two different approaches). The studies will be implemented in stages[91]:

- As of April 1, 2011, updated asset lives are incorporated into depreciation rates, for a reduction in annual depreciation expense of $33.9 million/year;
- As of April 1, 2012 further updated lives are apparently incorporated, for a reduction of $3 million/year; and
- At April 1, 2013[92], two new depreciation effects arise:
  - A further change in asset lives, for a reduction of $2.2 million/year; and
  - A change in depreciation methodology, from the ASL approach to the ELG approach, for a net annual increase in depreciation expense of $32.3 million. A further adjustment (reduction) to retained earnings of $31 million will also occur at transition[93].

In addition to the above, the study incorporates an elimination of net salvage from depreciation rates, which is addressed in a later section of this testimony.

In general, concerns with the study relate primarily to:

1) The proposed change to the ELG approach as being in "full compliance" with IFRS. This approach appears inconsistent with long-lived hydro-based assets, which are financed consistent with the Manitoba Hydro approach (primarily debt-financed, backed by an investment regime of Patient Capital (as defined in Section 2.2 of this submission)). The change to ELG is not required to comply with IFRS[94], and the primary other rationale offered by Manitoba Hydro in support of ELG (rate stability[95]) does not bear out on review.
2) The approach to amortizing material depreciation variances (approaching $600 million under ELG, much larger in the event the March 31, 2013 depreciation rates revert to the straight-line ASL approach[96]). The proposed approach leads to very little recognition of these variances in the early years of the application of the new rates.

[91] MIPUG/MH-1-15(p).
[92] Note that the April 1, 2013 date was timed to coordinate with the implementation of IFRS for Hydro. Manitoba Hydro has since indicated (MIPUG/MH II-1(a) that it will take advantage of a further one year delay in IFRS implementation to 2014/15. It is not clear if this will delay by one year the effects noted above.
[93] Appendix 5.5, Page 29.
[94] CAC/MH I-47(a).
[95] CAC/MH I-47(a).
[96] MIPUG/MH I-15(e) and (h).

The net effect of these aspects of the study is to propose a materially more aggressive depreciation methodology and associated cost for ratepayers compared with the current straight-line ASL, and a limited benefit for past variances. As a Crown-owned hydro-utility, an aggressive, ELG approach to depreciation with variances amortized over the remaining life appears to lead to an inferior outcome for the following reasons:

1) **Not consistent with peers:** No other Canadian Crown utility nor hydro-dominated utility is cited as making use of the ELG approach. This includes the following Canadian utilities as set out in Attachment C, Table C-1: BC Hydro and BC Transmission and Corporation; Newfoundland and Labrador Hydro; Northwest Territories Power Corporation; Qulliq Energy Corporation; SaskPower and Yukon Energy Corporation. The utilities specifically cited as using the ELG approach are predominantly private sector firms, using largely thermally-based generation[97].

2) **Not consistent with economic focus of IFRS standards:** The more aggressive ELG approach appears inconsistent with the spirit and intent of IFRS standard IAS 16, Section 60, which notes:

   > The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity[98].

   For a hydro asset such as Limestone, the "future economic benefits" are clearly large today and of increasing value into the future as a low-cost, long-lived and largely inflation-protected supply. Note also that Gannett Fleming does not base their study on this economic definition of depreciation, but rather on the "loss in service value" concept (which is not a concept cited in the IFRS standard). As set out in Attachment C to this testimony, this definition is more closely linked to engineering and accounting concepts of wear and tear or obsolescence.

3) **Not consistent with realities of hydro-generation:** The ELG standard reflects a perspective linked to asset depletion. However, hydro assets are not generally thought of as having their value "depleted" or "consumed" over time with use or even with deterioration. This is because the assets are very long lived and provide the largest part of their economic benefit in the middle to latter years of their lifespan (for example, Wuskwatim is providing very little to no net economic benefit early in its life). Further, for thermal assets the largest cost profile of the plant over its life is the fuel consumed not the capital invested; in the case of Hydro because the effective fuel supply to the plant is fully renewable, different economic considerations are relevant. Finally, a substantial component of the investment or value in a hydro asset is never "depleted" (such as the environmental/social general "licence" to develop and use a waterway

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[97] PUB/MH I-85(a).

[98] As provided in CAC/MH I-47(a).

and capture its energy for power production – even with a major rebuild of a plant the costs and efforts required are well below the scale required with Greenfield sites). As a result, more aggressive depreciation methods are not well suited to rate setting for hydro generation assets.

4) **Becomes barrier to new development:** Where new capital-intensive and long-lived assets are being assessed, the largest economic barriers to development are typically not related to life-cycle returns, but to onerous annual accounting costs in the early years of the project. Increasing the depreciation costs in these early years may serve to skew the ratepayer impacts of a project in its early years despite having no effect on the overall life-span economic profile. In the extreme, long-lived projects that would be materially beneficial to ratepayers after only 1-2 decades (such as Limestone) and remain so for the remainder of their life may not get built due to the degree of costs faced by ratepayers in the first 5-10 years. A change to an ELG approach only serves to exacerbate these effects and to make the project more onerous on ratepayers in the early years (when by their nature hydro projects may already be at a "tipping point" in terms of impacts on ratepayers) in favour of making the project more favourable to ratepayers in the later years (when ratepayers would have already been making out very well, such as today's ratepayers are from Grand Rapids or Limestone).

5) **Variances arising from past charges to ratepayers amortized over excessively long-life, inconsistent with intergenerational equity:** The proposal in respect of reserve variance amortization could be viewed as being inconsistent with the concept that the reserve variance arose from past rates. In particular, Hydro proposes to amortize only $7 million/year of a $594 million accumulated reserve variance[99] (using the ELG approach with no salvage; under an ASL approach with salvage the values are $7 million/year of a $552 million variance[100]; no values have been provided for an ASL approach with no salvage but the variance would be materially higher). Hydro asserts that this variance arose "over a long period of time"[101]; however, the variance as of the 2005 study was only $117 million[102]. The major contributor to the variance is the updated improved recognition of longer asset lives. While Hydro's proposal for amortizing the variance is not an uncommon regulatory approach, and is consistent with the concept that these "variances" are not fundamentally any sort of cash resource to be refunded to ratepayers, it still requires consideration from a perspective of intergenerational ratepayer equity.

[99] Appendix 5.7 November 2, 2011 Study. Page III-19.
[100] Appendix 5.7 January 13, 2012 Study. Page. 8.
[101] MIPUG/MH-1-15(j).
[102] Appendix 24, Page III-6.

Hydro's only substantive argument offered in favour of the ELG method relates to rate stability once IFRS is adopted and gains and losses on disposal must be recognized at the time an asset is retired. As noted by Hydro:

> The ELG method will minimize the amount of gains and losses recognized on retirement of assets, and will reduce net income volatility. As a result, the ELG method is the preferred approach for rate-regulated utilities as it is expected to promote rate stability for customers[103].

However, Hydro offers no calculations or data to support the assertion (MIPUG/MH II-10(a)). More notably, this assertion may be relevant to a utility which adheres strictly to annual revenue requirements; however, for Manitoba Hydro, the long-term financial targets and approach to regulation are designed to specifically absorb and balance year-to-year variability without creating rate instability (such as the 2004 $400 million drought loss). Further, the data in Appendix 16 (Manitoba Hydro's Service Life Statistics) shows an extremely limited record of retirements for most bulk power asset categories which are the assets most likely to be characterized by instability (the lone major exception is distribution asset retirements, which would be expected to be fairly predictable year-to-year[104]). As a result, there is no basis for concluding that retention of the straight-line ASL method under IFRS would create a new net income instability that approaches the scale of instability that is inherent in, and intended to be fully addressed by, current Manitoba rate setting approaches.

In summary, Hydro should reconsider and reverse their decision to adopt an ELG method of depreciation. Given its bias towards more aggressive depreciation in the early years and its adverse impacts on ratepayers today, as well as on the economics of new long-lived power projects, the method is poorly suited to Crown and hydro-based utilities.

A separate item of concern arising from review of Hydro's filing, but unable to be addressed in the time available, is the potential mis-estimation of lives in the following accounts, based on the data contained in Appendix 16:

- **Dams, Dikes and Weirs:** Proposed to be set at 125 years average life, but this life estimate has little practical effect as all dams, dikes and weirs are assumed to be fully retired concurrent with the related powerhouse. This would not seem to be a reasonable assumption given the long-term conceptual plans for rebuilding powerhouse assets rather than retiring generating stations.

[103] CAC/MH I-47(a).
[104] Distribution assets are shorter lived and asset retirements are considerably more predictable according to the data in Appendix 16, particularly for service extensions, poles and conductors.

- **Spillways:** Hydro's choice of Iowa curve is premised on the pattern that some 20% of spillway investments won't last the first 50 years, and 30% won't last the first 65 years. In contrast, Hydro shows basically no spillway retirements in its data.
- **Distribution:** In contrast, concerns are noted that Hydro's own data for retirement of distribution assets is very thorough, and does not support the lengthy lives adopted in this study; in particular accounts 4000J (Metal Towers) and 4000L (Overhead Conductors), which make up half of the depreciation asset category. Not only are the proposed lives unsupported by Hydro's data, but they also represent a large one-time change from existing depreciation lives (which is typically discouraged in any individual depreciation study, to help facilitate stability in transition), and appear inconsistent with Hydro's own assertions that the scale of retirements and capital spending on distribution need to be materially increased in future years due to "Aging Infrastructure", per Appendix 5.6 page 3 lines 17-19. Overstatement of asset lives can lead to the types of material losses on retirement and future instability noted as a concern in the Gannett Fleming materials with respect to making major changes at one time, rather than modest adjustments over subsequent studies, to the extent new data can support the changes.

4.2.3 Net Salvage/Future Removal

Hydro's depreciation study to be effective 2013/14 proposes a reduction in annual depreciation expense of $55.6 million/year[105] related to funding "net salvage" or the future costs of removing assets. A further adjustment to retained earnings of $53 million will also occur at transition[106]. As a result of this transition, the future costs to dismantle and salvage assets will be a component of reconstructing the new replacement assets at the site, or in the case of a total abandonment of a site, will be expensed[107].

Hydro's proposal reflects an approach that is becoming increasingly common in utility regulation, including hydro-based and Crown utilities.

The theoretical basis behind Hydro's proposed new approach to net salvage was summarized concisely in a report prepared for Newfoundland Hydro by KPMG in 1998, as follows:

> Alternative approaches to accounting for the net salvage values related to a retired asset are as follows:
>
> 1) Ignore salvage values in the calculation of the asset's depreciation rate. Recognize gross salvage revenue as income and retirement costs as an expense at the time the asset is retired.

[105] PUB/MH I-42 Schedule A Cont'd.
[106] Appendix 5.5, Page 29.
[107] CAC/MH I-48(b).

2) Ignore salvage values in the calculation of the asset's depreciation rate and include the net salvage incurred on the retirement of the asset in the depreciable cost base of the asset that replaces the retired asset.

3) Ignore salvage values in the calculation of the asset's depreciation rate and amortize the net salvage incurred on the retirement of the asset over a period following the retirement.

4) Alternatively, incorporate the asset's predicted net salvage value in the calculation of its depreciation rate.

5) Establish a separate reserve (or allowance) for net salvage for each account that is expected to have negative net salvage. Calculate and display this reserve separately from accumulated depreciation[108].

Option 4 above effectively summarizes Hydro's past approach, with Option 2 (or in certain circumstances Option 3) being the proposed go-forward treatment for Hydro major assets. KPMG explained the theoretical basis for Option 2 in more detail as follows:

2) Add negative net salvage costs to the depreciable cost base of the replacement asset: Under this approach, net salvage costs are added to the depreciable cost base of the asset that replaces the one that is retired. When a major asset is replaced by a new asset of the same nature at the same site (rather than abandoned), site restoration or rehabilitation is not required. The existing site will still be occupied by the new asset (most likely in an upgraded or improved form). Salvage will include the removal costs of the asset that is replaced, which will normally take place as part of the construction activities related to the new asset. In most cases it would actually be quite hard to separate the costs of the two activities. In the case of negative net salvage the rationale for this treatment is the assumption that any such salvage is most likely to be offset by construction cost savings attributable to the fact that the site has been previously occupied by a similar asset[109].

KPMG recommended Option 2 for major assets that are expected to be largely replaced at the same site on their retirement. This would appear to be relevant to all of Manitoba Hydro's major facilities.

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[108] 1998 KPMG Depreciation Policy Study for Newfoundland and Labrador Hydro. Provided in the response to Consumer Advocate Information Request CA-NLH-32 from the 2012 Depreciation Methodology Review. http://www.pub.nf.ca/applications/NLH2012Depreciation/files/rfi/CA-NLH-032.pdf.

[109] 1998 KPMG Depreciation Policy Study for Newfoundland and Labrador Hydro. Provided in the response to Consumer Advocate Information Request CA-NLH-32 from the 2012 Depreciation Methodology Review. http://www.pub.nf.ca/applications/NLH2012Depreciation/files/rfi/CA-NLH-032.pdf.

The decision to not include any further appropriations for net selvage is the same approach that has been adopted for a number of regulated Crown-owned utilities in Canada that, similar to Manitoba Hydro, have a large proportion of their generating complement invested in hydro assets. In addition to Newfoundland Hydro and Hydro Quebec[110] (at least as of 1998), this same approach is now used by BC Hydro[111] and Yukon Energy[112], pursuant to decisions of their respective regulators in the 2003-2005 period to remove the net salvage collection from depreciation expense.

In short, the approach proposed by Manitoba Hydro is appropriate, and is not necessarily linked to IFRS transition. The approach will result in some future costs for taking down assets to be either expensed in the year incurred or, more commonly, rolled into the capital cost of the replacement asset, but this approach is supported in depreciation theory as set out by KPMG above.

4.3 RESERVES AND RISKS

Hydro's portrayal of the utility's financial position continues to focus on two primary financial targets – the Interest Coverage ratio (an annual measure) and the Debt:Equity target (a long-term measure). Of the two, it has been a longstanding approach that progress towards the 75:25 Debt:Equity target is the dominant consideration. This is particularly true in light of the tendency for the Interest Coverage ratio to exhibit strong year-to-year variability arising from water flow and other variations.

The current GRA reports a shift away from progress towards the 75:25 Debt:Equity target, achieving only 81:19 and $2.2 billion in reserves (retained earnings) by the end of the test years for electric operations, even with the proposed rate increases[113]. This reduction is forecast despite having fully achieved the 75:25 ratio and $2.5 billion in reserves in 2012[114]. However, this picture of erosion is misleading:

- **Reported Reduction in Reserves:** The drop in retained earnings occurs despite positive net income each year. The vast majority of this drop is due to Hydro electing to derecognize all enduring value from Hydro's longstanding PowerSmart DSM programs in its financial statements (in excess of $180 million[115]). The one-time IFRS adjustment to retained earnings drives an

[110] 1998 KPMG Depreciation Policy Study for Newfoundland and Labrador Hydro. Provided in the response to Consumer Advocate Information Request CA-NLH-32 from the 2012 Depreciation Methodology Review. Page 17. http://www.pub.nf.ca/applications/NLH2012Depreciation/files/rfi/CA-NLH-032.pdf.
[111] British Columbia Utilities Commission BRITISH COLUMBIA HYDRO AND POWER AUTHORITY 2004/05 to 2005/06 Revenue Requirements Application Page 157 and 223 (October 29, 2004). http://www.bcuc.com/Documents/Decisions/2004/DOC_5432_BCH%202004RR%20Final.pdf.
[112] Yukon Utilities Board Order 2005-12, Appendix A at Section 8.1. http://yukonutilitiesboard.yk.ca/pdf/387_2005-12%20Appendix%20A.pdf.
[113] PUB/MH I-30(b).
[114] If AOCI is included, the ratio reach fully 72:28 for electric operations in 2011; however, this is not an ideal use of the AOCI concept, particularly given the instability of the AOCI value, as shown in MIPUG/MH I-11(c).
[115] PUB/MH I-42 Schedule B.

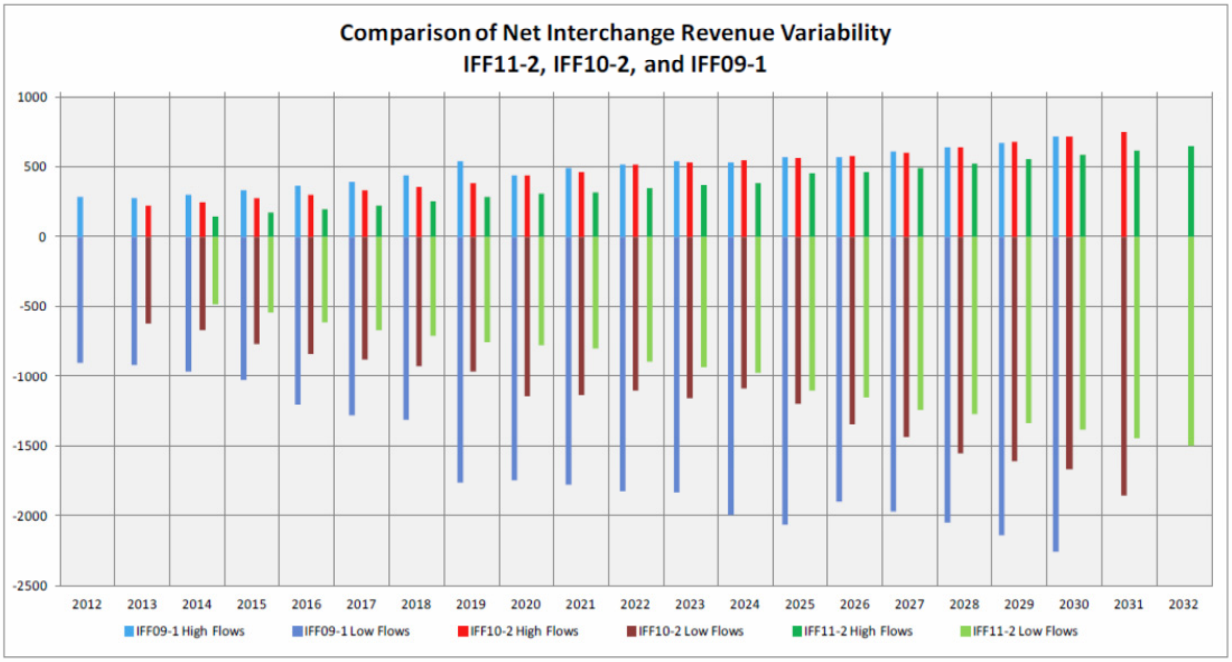
approximately 2.0 percentage point difference in the Debt:Equity ratio. Of further concern is that the change provides no new useful information about the degree to which Hydro is capitalized in a manner that protects it against drought or other risks, which is the very purpose of the reserves in the first place. The IFRS changes may be intended to more closely represent the shareholders "equity" in the company, in the form of assets that the shareholder controls or can liquidate (which it cannot do with PowerSmart), but in the case of Hydro where the sole purpose of the financial reserves is protection against adverse events (not to represent some measure of the value of the shareholder's investment), the investment in PowerSmart remains a valid and valuable asset that does not merit being derecognized.

- **Inflated Long-Term Debt Levels, Driven by Capital Investment:** Hydro's calculated Debt:Equity ratio is increasingly being driven by the debt values, which are forecast to exceed $10 billion in the test years. Of this amount, nearly one-quarter is related to projects which are not serving ratepayers in the test years ($1.4 billion for Keeyask and Conawapa, and $0.9 billion for Bipole III, plus a number of other smaller projects[116]).
- **Reduced Risks Related to Export Market Transactions:** As a result of changes in market values for power and fuel, the adverse impacts on Hydro of a drought (and other similar potential changes to forecast supply) are diminished as compared to earlier IFFs. This would appear to be for a number of reasons: 1) the opportunity exports that must be curtailed are of less value, 2) any replacement power that must be purchased from opportunity markets is lower cost, and 3) any fuel (particularly natural gas) required to provide supply from Hydro's own facilities is lower in cost. The GRA indicates, at Tab 9, page 25, that a 5 year drought, with compounded interest, is now $1.6 billion or 33% below the previous estimate of $2.4 billion. Further, projected net income over this period totals approximately $0.6 billion[117], so the total net loss in a repeat of the worst 5 year drought on record is now forecast at $1.0 billion[118].

The best illustration of the material reduction in risk is shown in PUB/MH I-33(c), which graphically depicts the impact of high and low water flows on the IFF Net Income results, by year, as shown in Figure 4-3.

[116] CEF11. Total Project Spending for Each Project excluding all remaining spending after 2013/14. Page 2.
[117] IFF 11-2. Electric Operations MH11-2, Sum of Net Income from 2013/14 to 2017/18.
[118] $1.6 billion less $0.6 billion net income.

Figure 4-3: Net Interchange Revenue Variability from PUB/MH I-33(c)



The chart in Figure 4-3 depicts at the $0 horizontal row Hydro's net income based on the mean of all flow conditions, and charts the degree to which those extreme flow conditions can lead to results that are more positive or negative than the mean. As for the past IFFs, shown the adverse effects of a drought are mathematically larger than the positive effects of a flood, but due to the $0 value being the mean, the likelihood that a given year will be somewhat better than the mean is much greater than that the year will be less. However, the most notable changes in the new data show on the bottom of the bars how much an extreme low flow year can adversely affect net income. In the IFF09, the potential impacts of the very worst drought years were very high; in contrast IFF11-2 shows that the size of the related bars (the financial impact of a one-year severe drought) is now much smaller. It is also important to note that the worst 5-year drought is not nearly as bad as 5 times the worst one-year drought shown in the figure above[119].

[119] For 5-year drought cost see Section 2.2.5 of this submission.

5.0 LEVEL OF RATES AND RATE OPTIONS

This section focuses on the sufficiency of Hydro's rates in light of the revenue requirement, and addresses the proposed changes to the Curtailable Rate Program.

5.1 SUMMARY OF EVIDENCE REVENUE REQUIREMENT: SUFFICIENCY OF RATES

Focusing on the information contained in Hydro's filing (as summarized in Section 3 of this submission) and the analysis of this information (Section 4 of this submission) in light of appropriate ratemaking principles (Section 2 of this submission), conclusions on the sufficiency of rates for the test years are as follows.

1) **Annual Contributions to Reserves:** Hydro's IFF11-2 forecasts understate the degree of net income or "contribution to reserves" that should be recorded in each test year. For 2013/14, recognizing the key changes set out in Section 4 of this submission, current year expenses should be reduced by up to $98 million (overheads), and a further $32 million (not adopt the ELG method of depreciation, but retain the straight-line ASL method with no net salvage), leaving a contribution to reserves of approximately $200 million assuming all rate increases are granted (compared to $68 million in IFF11-2). Net income or contribution to reserves would exceed $150 million if the April 1, 2013 increase is not granted.

2) **Reserve Levels and Debt:Equity Ratio:** IFF11-2 understates reserve levels for 2013/14, which in fact exceed $2.4 billion, and, with adoption of the measures noted in item (1) above, likely exceed $2.6 billion[120]. As to Debt:Equity, the capitalization of Hydro is very close to or slightly above 75:25 on assets in service[121] throughout the test years.

3) **Targeted Contribution to Reserves:** With the incorporation into the IFF of the new updated and much lower risk profile for Manitoba Hydro (i.e., lower cost droughts, risks related to export market declines and gas price reductions already largely priced into the IFF[122]), there is no evidence that reserves today are too low. Continued modest annual increases in reserve levels at average water flows are reasonable. A discussion may be required in future years in regard to the point at which ratepayer reserve levels become higher than can be justified on the basis of the evidence, and therefore do not justify ongoing contributions, but it does not appear that situation has been reached today.

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[120] $2.2 billion as per IFF11-2, plus approximately $0.2 billion to reverse PowerSmart/DSM write-off, plus enhanced net income of $0.1-$0.2 billion for adjusted ASL/ELG and overheads for 2012/13 and 2013/14.

[121] The equity side of calculation comprised of roughly $2.6 billion reserves plus $0.3 billion unamortized customer contributions, the debt side made up or $10.8 billion per PUB/MH I-30(c) less $1.4 billion for Conawapa and Keeyask Work-In-Progress and $0.9 billion for Bipole Work-in-Progress yields 25.4% equity.

[122] See, for example, MIPUG/MH I-21(a).

4) **Rate Stability:** Although the test year forecasts indicate that rate levels are sufficient, in the interests of long-term rate stability some degree of rate increases are advisable. This is in part intended to reflect the normal expectation of a progression towards the need for new, modern and higher priced sources of power with domestic load growth (presently this need is forecast for the 2020-2022 period). The rate changes that have already been implemented to date for the two test years, as compared to the final rates approved in the last order (1% + 2% + 2.5% = 5.5%) already exceed basic inflation. It is important to also note that further revenue-neutral changes to implement the cost of service study results will lead to some other classes seeing increases above this level within the same test years, and other seeing decreases from this level.

While a specific alternative rate proposal could be developed based on the information in IFF11-2, it would be preferable to review the updated information that is expected to be made available in IFF12-1[123], prior to finalizing the GRA recommendations.

5.2 CHANGES TO THE CURTAILABLE RATE PROGRAM

The level of rates to be charged to industrial customers in this proceeding includes the proposal to eliminate new customer access to the Curtailable Rate Program (CRP; also known as the Curtailable Service Program).

5.2.1 Background on the Curtailable Rate Program

The CRP was designed out of a joint working group between Manitoba Hydro and industry in the 1990s. The program has been amended a number of times since that original program was introduced. Today the CRP is a form of DSM as part of the PowerSmart program, and is the largest single capacity DSM program Hydro operates (228 MW, which is larger than Wuskwatim[124]).

Manitoba Hydro uses curtailable load to maintain operating and contingency reserves as a means of minimizing disruption to firm customers and meeting MISO obligations in the event of loss of generation or transmission. Customers who participate in the CRP nominate quantities of curtailable or firm load that they can forego in a given month, with a minimum of 5 MW. Curtailable load makes its greatest contribution to reliability during critical times as Manitoba Hydro's capacity surplus and the MISO capacity requirement is most acute during these periods. Curtailable load is also of high value at all times when water conditions are average or high, as Hydro is able to more fully dispatch its hydraulic units to take

[123] PUB/MH II-27(a).

[124] However, not all of this load is available at a given point in time, depending on a customer's usage pattern.

advantage of on-peak sales opportunities, rather than retaining some hydro unit capacity as idle to serve as reserve capacity[125].

During the period of April 1, 2011 to March 31, 2012 three customers participated in the CRP. The Reference Discount (maximum available discount) for the period was $3.17/kW of curtailable load with customers receiving monthly credits on their electrical bill totalling $481,000.

During this period there were ten curtailments: one under Option A (curtail within five minutes notice for a maximum of four hours and fifteen minutes), which was initiated to protect firm export schedules, and nine under Option R (same characteristics as Option A, but used as Supplemental Reserves under MISO reserve sharing), which were initiated in response to a contingency or disturbance[126].

5.2.2 Proposed Changes to the Curtailable Rate Program

The current GRA filing for the fiscal years 2012/13 and 2013/14 proposes further changes to the CRP.

Appendix 10.4 of the 2012/13 and 2013/14 General Rate Application is the amended Terms and Conditions of the Curtailable Rate Program (CRP). Key proposed changes are as follows:

- Curtailment Options "C" will no longer be available (options that involve 1 hour notice to curtail, as opposed to the Option A and R which have 5 minutes notice). The one customer under Option C will have the opportunity to switch to Option A or revert to firm service. Although the credit paid to the customers participating in these options is lower than the shorter-notice options (40% of the reference discount, versus 70% for Options A and R), Option C is cited as being of less practical value to Hydro.
- The CRP load cap will be reduced to 50 MW for Option R load (from the current 100 MW) and 180 MW for Option A and C loads (currently 230 MW), assuming that the Option C load converts to Option A. Should Option C load revert to firm service, then the cap for Option A will be reduced to 150 MW. The revised caps are cited as reflecting Manitoba Hydro's present circumstances with respect to capacity availability and MISO load sharing. The impact of the revised caps is a reduced maximum monthly program cost of approximately $200,000[127], but no practical savings compared to the actual pay-outs in 2011/12 given the programs were not fully subscribed.

[125] MIPUG/MH I-44(d) Attachment 1 Pages 2-3.

[126] Appendix 10.5, Page 4.

[127] Present maximum monthly program cost is $732,000, based on 100 MW of Option A at 70% of $3.17/kW ($222,000) plus 230 MW of Option A and C, which yield a maximum reference discount of 70% (representing Option A; Option C is 40%) of $3.17 (total $510,000). Revised maximum discount is $510,000 per month, based on $111,000 per month for reducing Option R availability by 50%, and $399,000 for Option A at the new 180,000 MW level.

The proposal to eliminate Option C is reasonable given it has been concluded by Hydro to be of limited practical value[128].

The proposals to reduce the caps on the availability of Options A and R should not be adopted. This is for three major reasons:

1) **Fail to Recognize Long-Term Value:** Participation in the program by a customer practically requires a long-term commitment, as their operations and facilities must be prepared to respond to major power supply changes within very short periods of time (less than 5 minutes). This can include making investments in capital assets and control systems, as well as in staff procedures and practice in implementing interruptions. For the customer, CRP participation is a long-term commitment.

   Hydro's case that the necessity of curtailable load has diminished is a very new situation. Specifically, the Hydro CRP reports from as recently as October 2011 noted that Hydro was reviewing the program caps with an eye to raising the levels (to as high as 400 MW of Option A as well as adding additional Option R)[129]. The same text was in Hydro's January, 2011 report[130]. Hydro also notes that the DSM value of the CRP is not included in the long-term resource assessments as "CRP customers are not obligated to make long-term commitments"[131]. However, this is no different than any other DSM program – customers are not formally obligated to continue using the efficient lights or motors, and specific buildings where improvements took place may be vacant or demolished, etc. Regardless, the preponderance of evidence is that the CRP program can continue into the future (like it has for more than 15 years), and, like any DSM, there is a high likelihood that there will be customers participating at that time. Without this long-term contribution being ascribed, there is a persistent tendency to under-recognize the value of CRP.

2) **Export Market Prices:** Hydro cites that the main rationale for imposing the new caps (despite recently indicating a potential expansion of the program) is the reduced need to carry contingency reserves under the MISO/MH Capacity Reserve Sharing Agreement dated October 19, 2009[132] and which came into effect January 1, 2010[133]. Note that this was well before the

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[128] Curtailable load can be valuable even in situations where curtailments do not occur, such as by permitting Hydro to continually dispatch its hydraulic units more fully to capture export market opportunities. It is noted however, that there has not been an Option C curtailment for at least 3 years per MIPUG/MH I-44(d) Attachments 1 and 2, and Appendix 10.4.

[129] MIPUG/MH I-44(d), Attachment 1 Page 10 of 12.

[130] MIPUG/MH I-44(d), Attachment 2 Page 10 of 12.

[131] PUB/MH I-141(a).

[132] MIPUG/MH I-44(h).

[133] CAC/MH I-84(c).

date where Hydro was still indicating that it may expand the CRP, as of October 2011[134]. The more notable factor that explains Hydro's view of a reduction in the value of curtailable load is the reduced spread between the prices for opportunity on-peak and off-peak sales[135]. Under normal water conditions, the availability of curtailable load permits Hydro to dispatch its hydraulic units more fully in all hours, which can help bring what would otherwise be off-peak sales into the on-peak. Under high water flows, additional on-peak sales can be achieved. The present low natural gas prices, and attendant lower on-peak/off-peak spreads, may serve to diminish curtailable value over the short-term. However, much as Hydro's planning, DSM, and IPP contracts look to the long-term value of export markets, so too is it appropriate to consider future price forecast in the assessment of the CRP value.

3) **Industrial Options:** There is at present extremely limited load related options for industrial customers to manage their costs for power in Manitoba. The elimination of this industrial rate option for any customers not presently on the program exacerbates this situation. Eliminating this option reduces flexibility for industrial customers.

For these reasons, the lower caps for CRP are not recommended. Despite the fact that Hydro's proposed caps provide for continued participation by all existing customers, they do not permit any new customers (or expansion by existing customers) to be included in the program. It is not apparent that there will be any practical effect of this recommendation – it is possible no new customers will come forward to use the added program room even if the higher caps are maintained. However, in the event they do, they are highly likely to be providing Hydro with a new long-term and reliable capacity resource that will outlive present export market conditions and MISO agreements.

[134] MIPUG/MH I-44(d), Attachment 1. Page 10 of 12.
[135] See, for example, Tab 9 Figure 9.5.1.

ATTACHMENT A: RESUME

InterGroup® CONSULTANTS

PATRICK BOWMAN
PRINCIPAL AND CONSULTANT

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

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

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Project development, 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. Major clients included the following:

- **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, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers, depreciation, as well as revenue requirements.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. 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 Applications and related Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity).

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

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

- **For NorthWest Company Limited (2004-2006),** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

- **For Yukon Energy Corporation (2005-current),** Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on ongoing 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets.

- **For Northwest Territories Power Corporation (2010-2012),** Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee.

- **For Northwest Territories Energy Corporation (2003-2005)**, 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 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 Power Major Projects Planning Department (1999-2002)**, initial review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

- **For Manitoba Hydro Mitigation Department (1999-2002)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. 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 alternative 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.

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

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 (MPUB)	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	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	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 (NLPUB)	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	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	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	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	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 Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	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	MPUB	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	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009-10	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	Pending
Manitoba Hydro	2010/11 and 2011/12 General Rates Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes

ATTACHMENT B: FINANCIAL RESULTS AND FORECASTS

Integrated Financial Forecasts

In the current proceeding, Manitoba Hydro has provided the Integrated Financial Forecast for 2011/12 (IFF11-2) information as part of its Application[136].

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

- IFF02-1 which Hydro indicates the Manitoba Hydro Board used in setting the original debt/equity target of 75:25 by 2011/12[137];
- IFF03-1 which was included with the 2004 General Rate Application[138];
- IFF04-1 which was included with Hydro's January 2005 Application in support of a 2.25% conditional interim rate increase[139];
- IFF-05-1 which is the IFF Hydro submitted when asked to identify the information it considered in making the decision to forego the October 1, 2005 conditionally approved rate increase of 2.25%[140];
- IFF06-3 – Consolidated Integrated Financial Forecast[141];
- IFF06-4 Statements[142];
- IFF07-1 which is the financial forecast primarily relied upon in the 2008 GRA[143];
- IFF09-1 Integrated Financial Forecast[144] which was the original basis for the 2010/11 and 2011/12 GRA; and
- IFF10-1 Integrated Financial Forecast[145] which was provided during the course of the 2010/11 and 2011/12 GRA.

136 Appendix 4.2 of 2012/13 and 2013/14 GRA.
137 PUB/MH I-23 a) from 2008 GRA.
138 Appendix 4.1 of 2004 GRA.
139 Tab 2 of January 2005 Application to Implement General Rate Increase.
140 Appendix 5.3 to the 2008 GRA, rate increase forego from Page i.
141 Appendix 5.2 to the 2008 GRA.
142 Appendix 5.1 to the 2008 GRA.
143 Appendix 22 to the 2008 GRA.
144 Appendix 5.2 to the 2010/11 and 2011/12 GRA.
145 Appendix 76 to the 2010/11 and 2011/12 GRA.

This section contrasts Hydro's actual performance[146] and forecasts with respect to key financial indicators in the different IFFs. The primary focus of this review is a comparison of IFF07-1, IFF09-1 and IFF10-1 (the IFFs primarily reviewed as part of the previous 2 GRA processes) with IFF11-2, which is the IFF included with Hydro's 2012/12 and 2013/14 GRA.

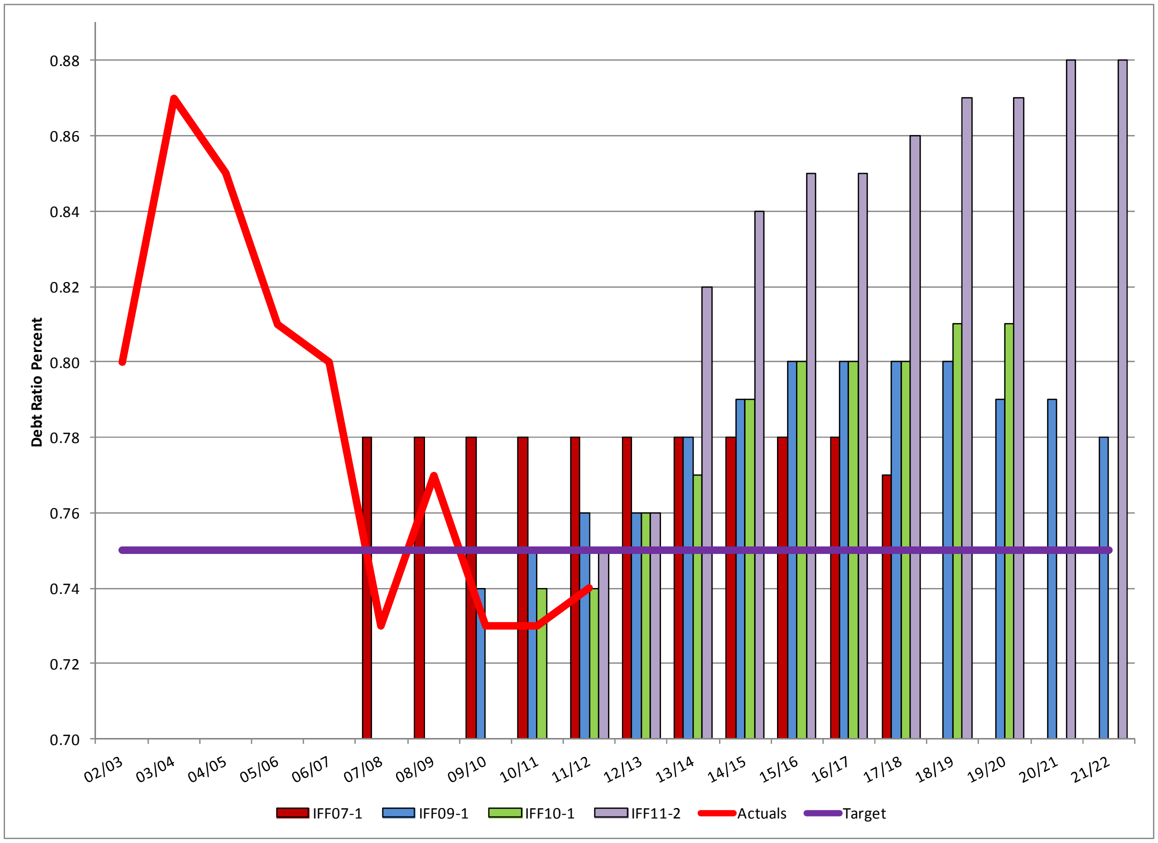
Debt to Equity Ratio

Manitoba Hydro has previously noted that its Board of Directors adopted a consolidated Debt/Equity target of 75:25 by 2011/12 in IFF02-1[147]. Hydro states in IFF11-2 that high levels of capital investment in major new generation and transmission combined with reduced net extraprovincial revenues result in a deterioration of the equity ratio[148] in forecast years. The debt to equity ratio for IFF11-2 is projected as high as 88:12 in 2021/22, remaining low for three years, before slowly reacquiring the 75:25 target in 2029/30[149], when a retained earnings level of $6.4 billion is attained.

Figure B.1-1 provides a comparison of the consolidated debt ratios for from IFF07-1, IFF09-1, IFF10 and IFF11-2. Figure B.1-1 also includes actuals for the years available. A review of Figure B.1-1 indicates that for actual years 2009/10 to 2010/11 there was an improved debt to equity ratio, with 2011/12 actual results just below the targeted 75:25. The forecast years 2012/13 to 2019/20 show a substantial increase in debt in IFF11-2 compared with IFF09 and IFF10. For the year 2028/29, IFF09 forecast a 51:49 debt to equity ratio, a year within the "decade of returns" as it was known in the 2010 GRA Proceeding[150] (the period that followed the first "decade of investment"); IFF11-2 now projects 78:23 debt to equity at that time. Although this is an erosion, it should be noted IFF11-2 still portrays a retained earnings as of that date of $5.7 billion compared to the $2.5 billion today. Annual rate increases of 3.5% until 2023/24 and then 2% each year after in IFF11-2 help avoid further erosion of the Debt:Equity ratio for the projected forecast period in IFF11-2[151].

[146] Actual information in this section is taken from the response to PUB/MH I-1, PUB/MH I-51, PUB/MH I-59, CAC/MH I-2(a), from the 2012/14 GRA; PUB/MH I-27, PUB/MH I-1a (revised) and CAC/MSOS/MH I-128 from 2010/12 GRA; Coalition/MH II-18a from 2008 GRA and the Manitoba Hydro 61st Annual Report.
[147] PUB/MH I -23 a) from the 2008 GRA.
[148] Appendix 4.2: Integrated Financial Forecast IFF11-2 from 2012/14 GRA; p. 13.
[149] P. 21 - 22. IFF11-2.
[150] Appendix 15: 20 Financial Outlook from 2010 GRA.
[151] Appendix 4.2: Integrated Financial Forecast IFF11-2 from 2012/14 GRA.

Figure B.1-1: Comparison of Consolidated Operation Debt Ratios[152]



The reasons for this erosion in the Debt:Equity ratio in 2014/15 and beyond reflect a number of factors:

- **Retained Earnings and AOCI:** Retained earnings represent the largest portion of the "equity" terms in Manitoba Hydro's Debt:Equity calculation. IFF11-2 forecasts show changes in retained earnings largely due to the conversion to IFRS in 2013. Hydro now also includes AOCI in its calculation of the Debt:Equity ratio. This inclusion has led to a higher degree of instability in the equity component than prior to Hydro's decision to include AOCI in the calculation. Given AOCI largely represents changes in unrealized components of Hydro's costs, its relevance as part of a long-term financial metric each year is not clear. This is further addressed in Section B-1 below.
- **Domestic and Export Load Levels and Rates:** In its application, Hydro notes IFF11-2 forecasts lower electric operations net income of approximately $1.0 billion over the ten year period to 2021/22 mainly due to lower electricity export prices. General Consumers revenue is

[152] Data for IFF07-1 Debt Ratios from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Consolidated Operating Statement (p.23). IFF09-1 data from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Consolidated Operating Statement (p. 24). IFF-10 debt ratio data obtained by subtracting Equity Ratio from 100%--Equity ratio from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Consolidated Operating Statement (p.23). 2003-10 Actual data from Manitoba Hydro 59th Annual Report (p.100). IFF11-2 data debt ratio data obtained by subtracting Equity Ratio from 100% -- equity ratio from Manitoba Hydro IFF11-2 Appendix 4.2. 2009/10 to 2011/12 Actual data from Appendix 5.8: Manitoba Hydro 61st Annual Report (p. 86).

higher however; due to projected higher domestic customer growth and higher projects rate increases[153]. 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:** Increasing capital costs are often cited as another reason for the erosion of the Debt:Equity target. A comparison of Net Plant in Service is provided in Section B-3 of this Attachment.
- **OM&A Expenses:** The Board and intervenors have for many years been concerned with respect to the ongoing increases in Hydro's OM&A expenses. Trends in OM&A are reviewed in Section B-4 of this Attachment.

B.1: Retained Earnings

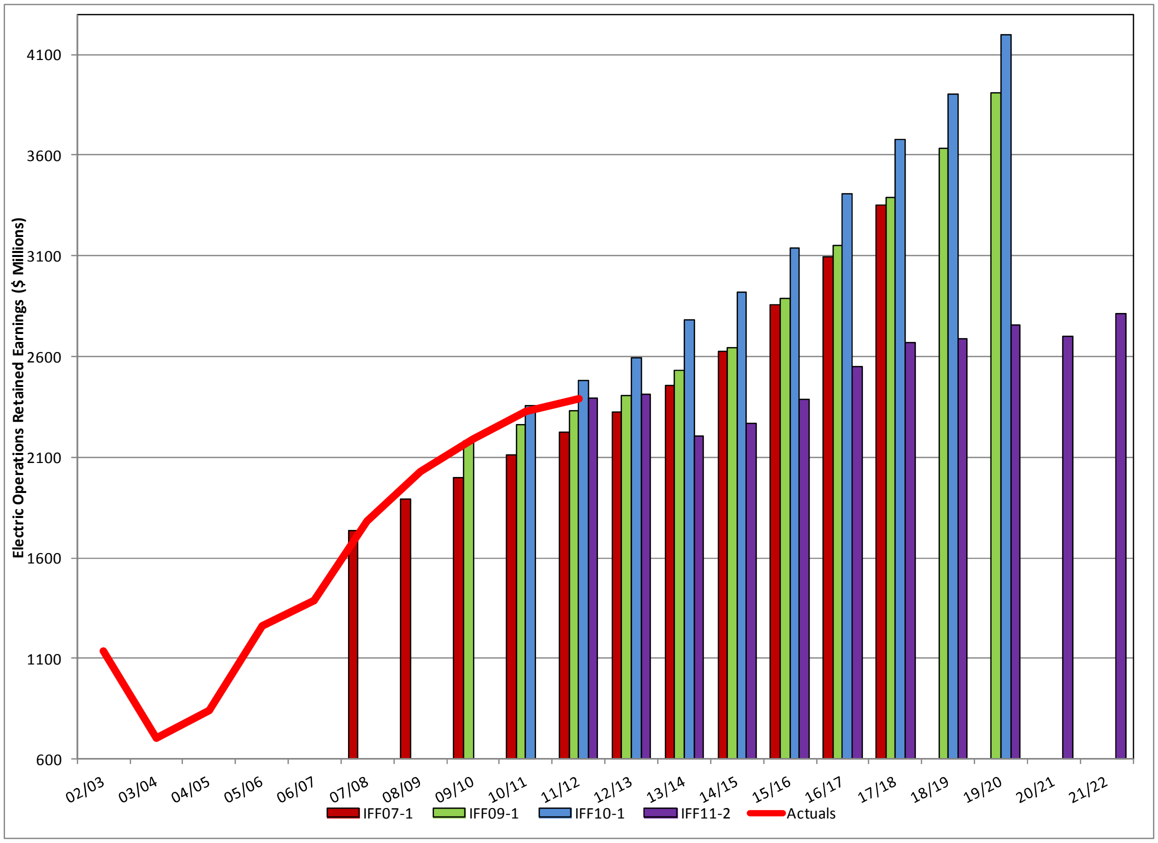
Figure B.1-2 compares actual electric operations retained earnings and forecasts from IFF07-1, IFF09-1, IFF10 and IFF11-2. A review of Figure B.1-2 indicates that 2007/08 retained earnings were approximately the same as the IFF07-1 forecast ($1,795 million in actual compared to $1,735 million in IFF07-1) and have continued improving into 2011/12 to $2.39 billion relative to IFF07-1 forecasts of $1.891 billion and IFF09 forecasts of $2.33 billion.

Retained earnings are proposed to see a large downward adjustment for IFRS conversion, which at the time of the Application filing was slated to take place for the 2013/14 year. Retained earnings forecasts in IFF11-2 for electric operations show a drop in 2013/14 to $2.2 billion, mainly due to the transition to IFRS which has an impact of in excess of $288 million in 2013/14[154]. A further $21 million in 2013/14 is deducted from retained earnings for CGAAP changes[155]. Changes to the approach to capitalization of costs reduces retained earnings by over $120 million per year[156].

Retained earnings forecasts for the years 2011/12 through 2019/20 are lower for IFF11-2 compared to IFF09-1 and IFF10. As at 2019/20, retained earnings forecasts are $3.904 billion and $4.196 billion in IFF09 and IFF10 respectively. For IFF11-2, the forecast for 2019/20 is $2.757 billion (nearly 35% lower than IFF10). Despite this reduction, retained earnings continue to progress towards the $3 billion mark within the IFF decade, and surpass this level absent the IFRS adjustments.

[153] Tab 4: Integrated Financial Forecast and Economic Outlook; p. 4.
[154] PUB/MH I-42 Schedule B. Total IFRS changes to Retained Earnings in 2013/14.
[155] PUB/MH I-42 of 2012/14 GRA.
[156] Sum of CGAAP Changes Annual change to OM&A and IFRS Changes Annual change to OM&A from PUB/MH I-42.

Figure B.1-2: Comparison of Electricity Operation Retained Earnings ($ millions)[157]



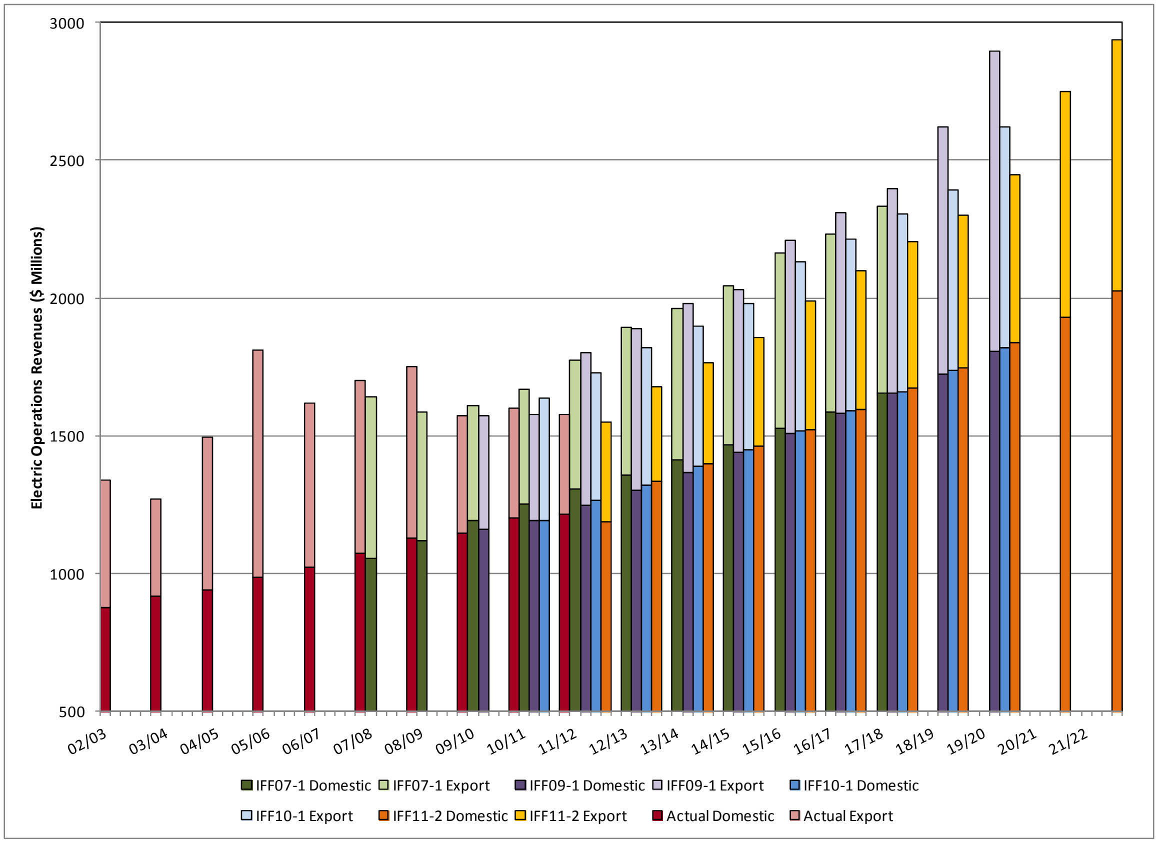
B.2: Total Electric Revenues

Figure B.2-1 compares actual electricity revenues (domestic and exports) to forecast revenues in IFF07-1, IFF09-1, IFF10 and IFF11-2. Forecasts in IFF11-2 show a further decline in overall electricity revenues compared to previous forecasts, with slight growth in the domestic revenues. IFF11-2 was prepared later than usual, so "expected" water flows were used in its preparation instead of the more typical "median" inflows approach for 2012/13. As a result net extraprovincial revenue in 2012/13 is lower than it would be under the median flow approach, a nearly $32 million decrease[158].

[157] Data for 2002/03 actual Electric Retained Earnings from 2008 GRA Coalition/MH II-18a; 2004-06 actual Electric Retained Earnings as per PUB/MH I-1 (Revised) from the 2010/12 GRA. IFF07-1 data from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Electric Operations (MH07-1) Projected Balance Sheet (p.39). IFF09-1 data from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Electric Operations (MH09-1) Projected Balance Sheet (p.35). IFF10-1 data from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Electric Operations (MH10) Projected Balance Sheet (p. 34). IFF11-2 data from Manitoba Hydro IFF11-2 Appendix 4.2 of 2012/14 GRA. 2007/08 to 2011/12 Actuals from PUB/MH I-1 and CAC/MH I-2(a) and do not include electric subsidiaries to match forecast.

[158] Appendix 4.2: Integrated Financial Forecast IFF11-2; p. 3.

Figure B.2-1: Comparison of Electricity Operation Revenues ($ millions)[159]

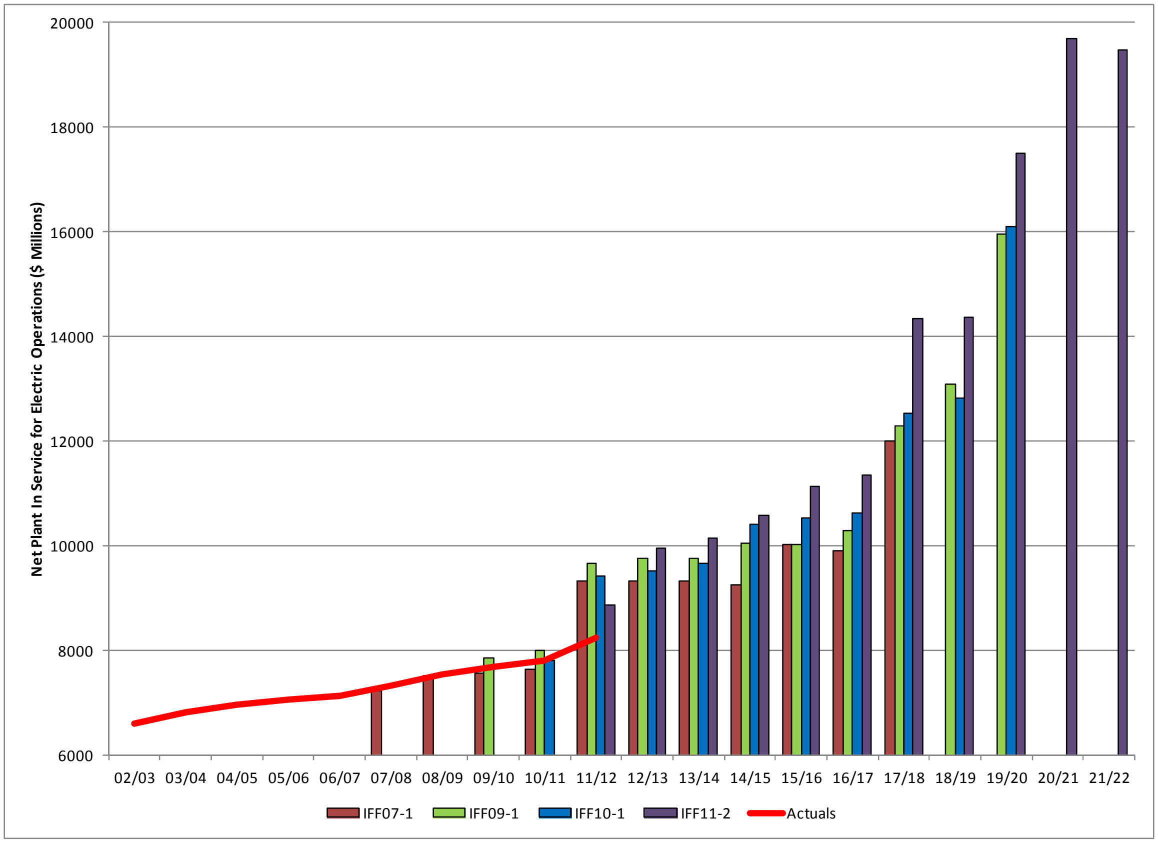


B.3: Net Plant in Service

Figure B.3-1 compares the net plant in service on an actual basis and forecasts in IFF07-1, IFF09-1, IFF10 and IFF11-2. The IFF11-2 forecast is higher on a per year basis than IFF09-1 and IFF10 forecasts; which in turn were both higher than IFF07-1 forecasts. This increase appears to relate primarily to higher assumed costs for Bipole III (as IFF10 was prepared prior to the Bipole III cost escalation noted in Exhibit MH-156 from the previous GRA).

[159] Domestic Revenues calculated as (general revenues at approved rates + general revenues at additional rates). Note: 2011/12 Actual Domestic Revenue includes $23 million in 1% rate deferral to reflect the rates paid by domestic customers in this year. 2002/03-2003/04 actual Electric Revenues as per Coalition/MH II-18(a) from the 2008 GRA. 2004/05-2008/09 actual Electric Export Revenues as per PUB/MH I-27 from the 2010/12 GRA. 2004/05-2008/09 Actual Domestic Electric Revenues as per PUB/MH I-1a (revised) from 2010/12 GRA. 2009/10 to 2011/12 Actual Domestic and Export revenues as per PUB/MH I-1 of 2012/14 GRA. IFF07-1 Electric Revenue from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Electric Operations (MH07-1) Projected Operating Statement (p.38). IFF09-1 Electric Revenue from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Electric Operations (MH09-1) Projected Operating Statement (p.34). IFF10-1 Electric Revenue from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Electric Operations (MH10) Projected Operating Statement (p. 33). IFF11-2 Electric Revenue from Manitoba Hydro IFF11-2 Appendix 4.2 from 2012/14 GRA Electric Operations (MH11-2) Projected Operating Statement (p. 31).

Figure B.3-1: Comparison of Electricity Net Plant in Service ($ millions)[160]



B.4: Operations, Maintenance & Administration Expense

Figure B.4-1 compares Hydro's OM&A by year for recent IFFs and actuals through 2011/12. A review of Figure B.4-1 indicates that Hydro's OM&A forecasts have generally trended higher for each IFF, with IFF11-2, the highest of the group, substantially increasing in 2012/13 and 2013/14.

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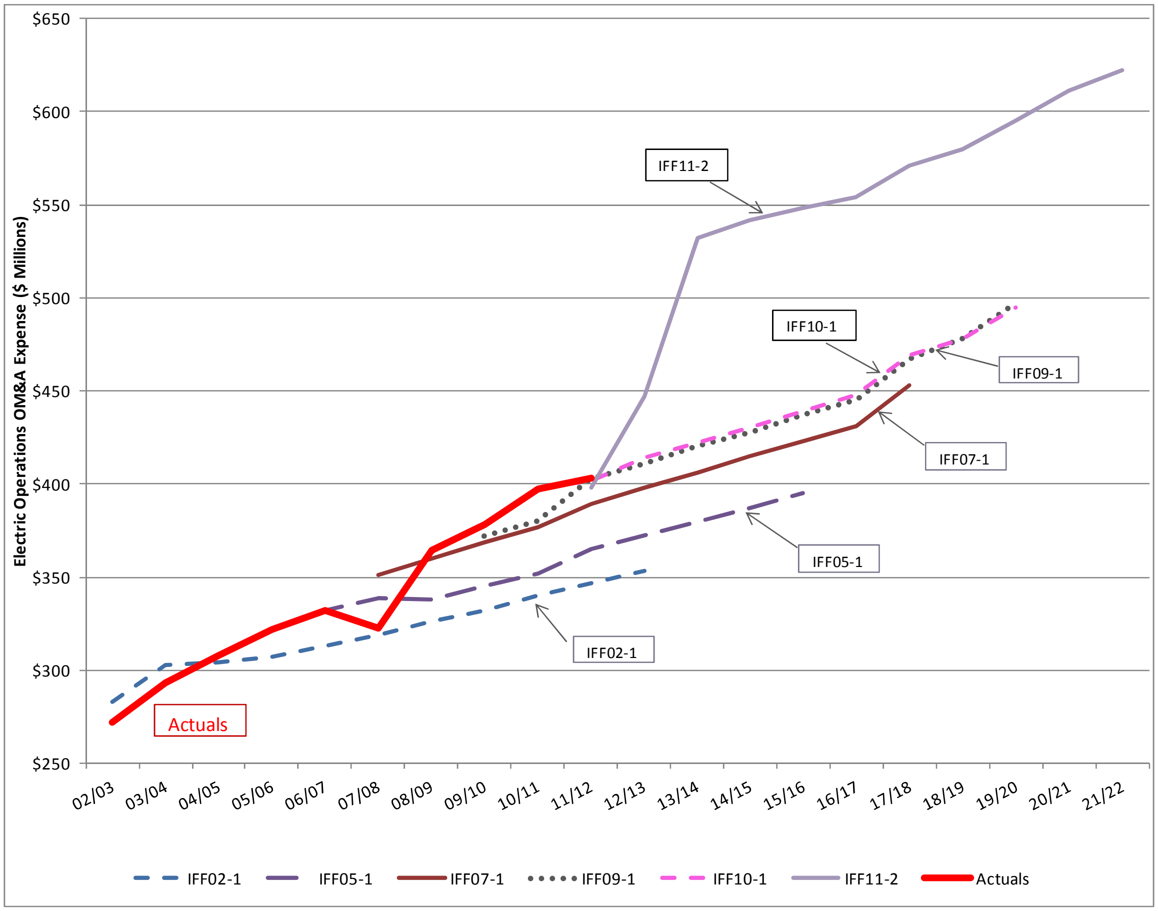
[160] Data for 2002/03-2003/04 actual Electric Net Plant in Service from 2008 GRA Coalition/MH II-18(a). 2004/05-2008/09 data for actual Electric Net plant in Service as per PUB/MH I-27. 2008/09 to 2011/12 actual information from PUB/MH I-51 of the 2012/14 GRA. IFF07-1 data from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Electric Operations (MH07-1) Projected Balance Sheet (p.39). IFF09-1 data from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Electric Operations (MH09-1) Projected Balance Sheet (p.35). IFF10-1 data from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Electric Operations (MH10) Projected Balance Sheet (p. 34). IFF11-2 from Appendix 4.2: Integrated Financial Forecast IFF11-2 Electric Operations (MH11-2) Projected Balance Sheet (p. 33).

1 **Figure B.4-1[161]: Comparison of Electricity Operations, Maintenance &**
2 **Administration Expense ($ millions)**



3

[161] Forecasts taken from each of the referenced IFFs, Projected Operating Statements. Forecast OM&A electric expense from IFF02-1 to IFF07-1 includes the OM&A expense for electric subsidiaries. Forecast OM&A expense for IFF08-1 to IFF11-2 does not include the electric subsidiary OM&A portion. 2002/03-2006/07 actual Electric OM&A data taken from Coalition/MH II-18a from the 2008 GRA and includes the OM&A expense from electric subsidiaries. 2007/08 to 2011/12 data as per PUB/MH I-51 from the 2012/14 GRA and does not include the electric subsidiary portion of OM&A. IFF11-2 includes addition of annual DSM expense as a result of IFRS conversion, beginning in 2013/14.

ATTACHMENT C: DEPRECIATION PRINCIPLES AND APPROACHES

The concept of depreciation for regulated utilities is discussed in detail in a manual prepared by the National Association of Regulatory Utility Commissioners (NARUC) in 1996, entitled "Public Utility Depreciation Practices". At the outset, the following concepts are noted:

> In everyday speech, depreciation generally means a decrease in the value or worth of an asset. The goal of depreciation is to allocate or assign a dollar amount to the reduction in worth or value occurring in the accounting period. This reduction starts when the asset is placed in service and usually continues throughout its life. The value of an asset is considered as being used up or consumed in the production of service. Consequently a charge is made to the cost of production, over the asset's life, by some equitable method of allocation. Thus, depreciation accounting is fundamentally a process of allocating in a systematic and rational manner the value of a depreciable asset over its life[162].

The Gannett Fleming study included at Appendix 5.7 of Hydro's filing provides a more specific definition applied in their assignment:

> Depreciation, in public utility regulation, is the loss of service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance[163].

This is consistent with the definitions adopted by the National Association of Railroad and Utilities Commissioners in 1958[164].

With the implementation of IFRS, new definitions of depreciation are imposed. In particular, the IFRS sections relevant to depreciation are set out in CAC/MH I-47(a), as follows:

> IFRS section IAS 16 Property, Plant & Equipment paragraphs:
>
> 50 The depreciable amount of an asset shall be allocated on a systematic basis over its useful life.

[162] National Association of Regulatory Utility Commissioners (1996). Public Utility Depreciation Practices, Page 11.
[163] Gannett Fleming January 13, 2012 study, at Page II-2 (included in Appendix 5.7 of Hydro's GRA filing).
[164] NARUC, 1996. Page 13.

> 57 The useful life of an asset is defined in terms of the asset's expected utility to the entity. ,..., The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.
>
> 60 The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity.
>
> 68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit and loss when the item is derecognized (unless IAS 17 requires otherwise on a sale and leaseback). Gains shall not be classified as revenue.

Of particular note, section 60 now places a focus on the consumption of the "asset's future economic benefits", as opposed to the earlier definitions of consumption of "service life".

Other Jurisdictions

Every relevant public utility is required under CGAAP or IFRS to adopt a method of depreciating their respective assets. A brief summary of relevant facts from the record of the current proceeding and publicly available documents is provided below.

In PUB/MH I-85(a) Gannett Fleming provides a list of North American utilities that use the ELG approach to calculating depreciation expense[165]. While most examples provided are American utilities, all of the Canadian examples provided are privately owned utilities with limited hydraulic generation and shorter-lived assets. In addition, 5 of the 9 Canadian utilities are Alberta-based and 2 are northern subsidiaries of Alberta-based parent utilities.

In contrast, every Crown-owned utility and hydro-dominated utility cited in the evidence and available for review uses the ASL procedure, as shown in Table C-1.

[165] With one apparent error – Qulliq Energy Corporation does not use the Equal Life Group approach, confirmed in MIPUG/MH II-9(c).

Table C-1: Depreciation Methods for Crown-Owned Canadian Utilities[166]

Utility	Depreciation Expense Calculation Method	Inclusion of Net Salvage in Depreciation Rates	Study Date
BC Hydro	Average Service Life Method[167]	Not Included - Future Removal and Site Restoration [FRSR] was removed from depreciation expense in 2004. The BCUC order that the $233 million in accumulated FRSR was removed from depreciation and a regulatory account was set up; where any incurred net salvage costs are deducted[168].	Gannett Fleming in 2006
BC Transmission Corporation	Average Service Life Method	Not included	Gannett Fleming in 2005
Newfoundland and Labrador Hydro	Average Service Life Method[169]	Not included[170]	Gannett Fleming in 2011
SaskPower	Average Service Life Method [171]	Not available	Gannett Fleming in 2011
Yukon Energy Corporation	Average Service Life Method[172]	Not Included - The Yukon Utilities Board Order 2005-12 directed a termination of any further appropriations to Yukon Energy's reserve for future removal and site restoration in 2005[173].	KPMG in 2012
Qulliq Energy Corporation	Average Service Life Method	Not Included	Gannett Fleming in 2011
Northwest Territories Power Corporation	Average Service Life Method	Included	Gannett Fleming in 2012

[166] Information in table from MIPUG/MH II-9(c) of 2012 GRA unless otherwise referenced.
[167] As per BC Hydro and Power Authority F2012 - 2014 Revenue Requirements Application; Appendix G: Review of BC Hydro's Implementation of International Financial Reporting Standards by Gannett Fleming. Page 8 (January 24, 2011).
[168] British Columbia Utilities Commission British Columbia Hydro and Power Authority 2004/05 to 2005/06 Revenue Requirements Application. Page 157-158, 223 (October 29, 2004).
[169]Newfoundland and Labrador Hydro Depreciation Study. Page 2-3 (September 7, 2011) http://www.pub.nf.ca/applications/NLH2012Depreciation/files/applic/NLH2012DepreciationApplication.pdf.
[84] Newfoundland Hydro 2012 Depreciation Methodology Review. Direct Testimony of Pat Lee. Page 5 (October 3, 2012) http://www.pub.nf.ca/applications/NLH2012Depreciation/files/reports/IC-ExpertReport-Oct3-12.pdff.
[171] MIPUG/MH II-9(c) of 2012 GRA and SaskPower 2013 Rate Application. Section 3.2.3: Depreciation & Amortization. Page 27 (June 2012) http://www.saskratereview.ca/images/docs/saskpower-2012/2013_rate_application.pdf.
[172] Yukon Energy Corporation, 2012 General Rate Application. Tab 10: Depreciation Study by KPMG. Page 10-7 (March 1, 2012). http://yukonutilitiesboard.yk.ca/pdf/1338_YEC%202012_2013%20GRA%20FINAL_2012%2004%2027%20Tabs%201-11.pdf.
[173] Yukon Utilities Board Order 2005-12. Directive 14. Page 3 (October 18, 2005) http://yukonutilitiesboard.yk.ca/pdf/109_boardorder2005_12.pdf.