PRE-FILED TESTIMONY OF

P. BOWMAN

IN REGARD TO MANITOBA HYDRO

2014/15 & 2015/16 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 FIGURES

LIST OF TABLES

ATTACHMENTS

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

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's ("Hydro" or "MH") General Rate Application ("Application" or "GRA") for 2014/15 and 2015/16 test years that are of interest to industrial customers. In the Application, Hydro requests final approval of the 2.75% interim rate increase granted effective May 1, 2014; a rate increase of 3.95% effective April 1, 2015; and a subsequent 3.95% rate increase effective April 1, 2016.

The Public Utilities Board ("PUB" or "Board") in its letter dated January 27, 2015 indicated that it would review Hydro's request for the finalization of the 2.75% interim rate effective May 1, 2014 and the request for a rate increase of 3.95% effective April 1, 2015 for the fiscal year 2015/16. In the same letter the Board indicated that it did not consider interim rates effective April 1, 2015 to be in the public interest and in this GRA process is seeking to set final rates. The Board also indicated, that pursuant to Board Order 49/14, the Board would not be reviewing or approving rate increases effective April 1, 2016.

Hydro applied to review and vary the Board's decision on January 30, 2015, which consistent with Order 49/14, was denied by the Board in Order 17/15. This Order stated that forecasts for the April 1, 2016 to March 31, 2017 fiscal year will be reviewed in this GRA hearing, and that it is open to the Board to provide further direction in its final GRA Order as to any additional information to be filed and considered before determining whether any process should be instituted for possible April 1, 2016 interim rates.

The 2016/17 fiscal year has been included in the review and analysis for this GRA. It is anticipated that if rate increases are accepted by the Board for the 2015/16 fiscal year they will become effective following the duration of the GRA process, around July or August, 2015.

Pursuant to Board Order 18/15 the scope of review for this evidence includes:

- Manitoba Hydro's revenue requirement and financial targets, including reprioritization of financial targets towards cash flow;
- A review of Hydro's capital spending including justification for expenditures;
- For Hydro's Operating Maintenance & Administration ("OM&A") forecast, reviewing Hydro's approach to budgeting and cost control methods for OM&A, Equivalent Full-Time ("EFT") staffing forecasts and the allocation of costs between operating and capital for ratemaking purposes;

- The appropriateness of Hydro's approach to depreciation for rate regulation purposes, including the consistency requirements for depreciation between ratemaking and financial reporting;
- The overall impacts of accounting policy changes, particularly related to IFRS, for rate setting;
- Impacts of Demand Side Management ("DSM") expenditures, deferral accounts and cost estimates on rates; and
- Hydro's proposal for finalization of changes to the Curtailable Rate Program ("CRP").

Consistent with Board Decision 18/15 this testimony does not address matters related to Hydro's Cost of Service study and methodology, class differentiated rate increases to the various classes, industrial Time of Use Rates or proposed revisions to the demand billing provisions in the industrial rate schedules. From comments made in the PUB letter dated January 27, 2015, the Board indicated that Manitoba Hydro's Cost of Service Study Methodology review, which was to be conducted after MH's last GRA, has not yet been filed by MH and approved by the Board. The Board expects this Cost of Service Study Methodology to be filed and reviewed before the GRA for any revised rates in the 2016/17 fiscal year, likely occurring later in 2015.

This testimony does not address matters relating to Directive 10 of Board Order 43/13 which requested that Hydro file a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Consistent with the PUB letter dated January 27, 2015 and Order 33/15, this information is best suited to a more comprehensive risk review once Manitoba Hydro's commissioned report by KPMG has been received, likely at the next GRA.

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

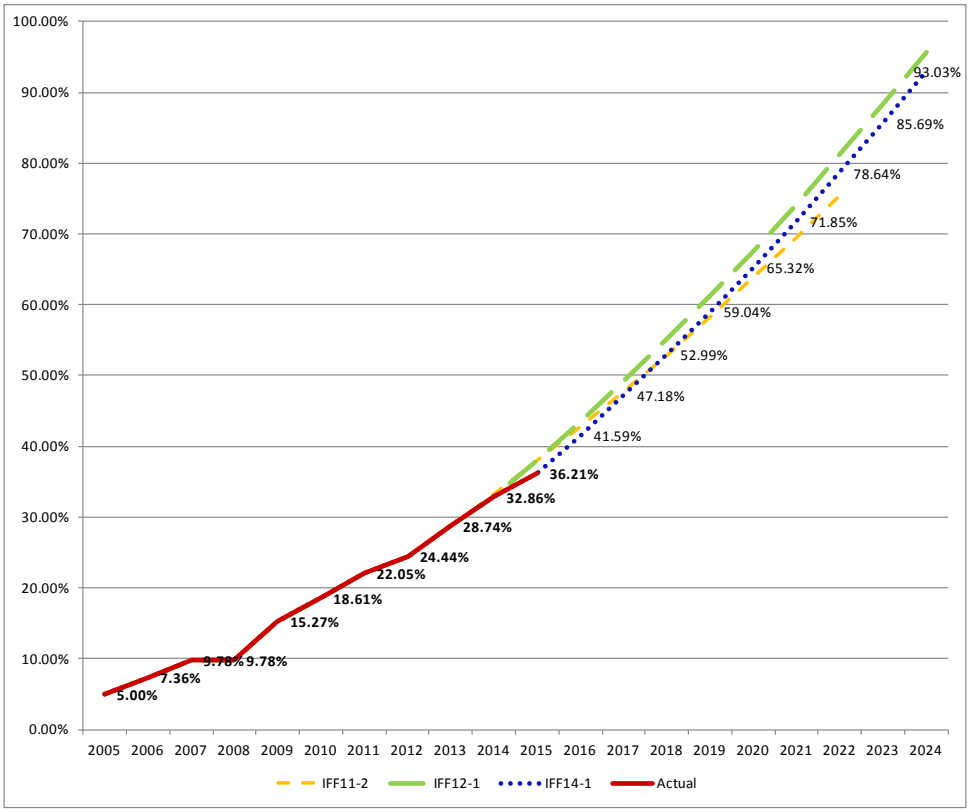
- The Hydro 2014/15 & 2015/16 General Rate Application, including most appendices and minimum filing requirements, and the responses to several Information Requests to Hydro.
- To a limited extent, filings from Hydro's NFAT proceeding, Hydro's evidence in the 2012/13 & 2013/14 GRA proceeding and earlier rate hearings as they relate to the current proceeding.
- Insights regarding Manitoba Hydro's 2014 Depreciation Study in comparison to industry standards from Patricia S. Lee, an established expert on depreciation studies in North America for use in utility rate regulation.

1.1 APPROACH TO REVIEW

This testimony focuses on the failure of the Application to justify the high level of overall across-the board rate increases requested for 2014/15 and 2015/16, particularly when viewed in the context of Hydro's recent NFAT hearing filings and the decisions resulting from that hearing.

The 2014/15 and 2015/16 Application filed by Manitoba Hydro follows electricity rate increases in the 2008/09 GRA, the 2010/11 & 2011/12 GRA and the 2012/13 & 2013/14 GRA. There is every indication that Hydro will file a GRA following this one for further rate increases. Recent electricity rate increases have been across-the-board increases and not guided by cost of service study results to address the disparity between cost of service and revenues at existing rates for specific customer groups. The result, as seen in Figure 1 is cumulative actual and forecast rate increases approaching 100% over the twenty year period 2004/05 to 2023/24.

Figure 1: Cumulative Actual and Forecast Rate Increases



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.

However, when compared to the review of a typical GRA, review of the rate increases requested in the current Application occurs during a period of particular uncertainty. In particular, five complicating factors are noted:

- The financial targets that Hydro uses to set net income and retained earnings requirements are currently being reviewed; therefore, for this proceeding they are not reviewed in detail nor used as a guide to set rates;
- DSM spending and programming comprise a substantial portion of Hydro's forecast cost increases in the Application, but the responsibilities and future directions for these programs are in the process of being reviewed as a result of the NFAT proceeding, and Manitoba Hydro and its ratepayers may not in the future have responsibility for these costs;
- Although capital expenditures for Conawapa have been deferred indefinitely following the recent NFAT hearing, the Application forecasts additional capital expenditures for sustaining capital resources (i.e., expenditures not included in the recent NFAT hearing evidence) and the basis for these new capital expenditures remains unclear;
- Changes to accounting methods resulting in effects to depreciation, OM&A and capital expenditures that have material effects on the timing of when these costs are recovered through rates, i.e., these accounting changes are shifting costs to current ratepayers and increasing the rate increases requested today in the Application; and
- Manitoba Hydro's information provided in the Application and in response to information requests from participants in this specific proceeding has failed on many key topics to provide the evidence needed to explain adequately the need and justification for the rate increases being requested at this time.

This pre-filed testimony prioritizes select topics that have near-term rate impacts on customers. It does not canvass topics recently reviewed in detail by the PUB (including load forecast, general OM&A, and export revenues forecasts) and avoids topics that remain outstanding pending a future review (including financial targets and risk, program specific DSM costs, Cost of Service and rate design).

1.2 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Compared to Hydro's forecasts reviewed only one year ago during the recent NFAT proceeding, the Application shows substantial deterioration in financial performance over the next ten years relative to targets. As a result of this new evidence, Hydro indicates it has an urgent need now to improve its cash flow from operations to address its ability to fund its sustaining capital program - and suggests that the applied for rate increases can be justified in part by this new need. However, based on the evidence provided to date by Hydro, there is considerable uncertainty about the key drivers of this deterioration and a limited ability to evaluate the reasons for this rapid decline. There is also no apparent basis to conclude that the level of rate increases requested today are adequately justified, or are what is needed to address the forecast deterioration in financial performance.

In summary, review of the evidence identifies the following three broad areas of change affecting the rate increases requested in the Application:

- **Material increases in spending that have not been adequately justified:** In several areas Hydro has not provided sufficient explanation for notable increased spending that is affecting the Application's requested rate increases, including:
    - Capital spending on non-major capital projects appears to have increased, notwithstanding accounting changes which should generally have reduced capitalized overheads (as described in section 3 of this testimony).
    - Hydro’s overall explanation of its approach to developing its current OM&A budgets, with related near-term cost increases compared to recent forecasts despite suggested new cost control measures, is not transparent or adequate (as described in section 4 of this testimony).
    - It is difficult to confirm how Hydro's plans to reduce its salary costs and staffing levels are reflected in the test year forecast which shows increased rather than reduced costs (as described in section 5 of this testimony).
    - Hydro has not adequately explained or justified substantially higher overall net plant in service costs than the forecasts previously reviewed a year ago for similar development plans during the NFAT proceeding (as described in section 6 of this testimony).
    - Hydro has not adequately explained or justified substantially higher DSM spending that involves largely placeholder amounts. There is also concern with respect to the economic viability of some planned DSM spending, as well as uncertainty with respect to whether Manitoba Hydro or some other government entity will assume responsibility for DSM programming. Comments in this area are provided in section 8 of this testimony.

- **Cumulative effect of accounting changes not adequately justified in the context of fair and reasonable charges to current day ratepayers:** Hydro has made a number of accounting changes that, when applied to revenue requirements used for setting regulated rates, generally have the effect of moving costs that were previously capitalized (and thus charged to future ratepayers) into operations and maintenance expense (and thereby charged to current day ratepayers). These changes result in substantial increases in test year costs as described in section 3.1 of this testimony. In assessing these new test year charges for the purpose of setting regulated rates, it is necessary (as in the past) for the Board to ensure that costs are fairly apportioned to customers based on the time periods (years) when the benefits of spending are expected to arise rather than on any suggested need to strictly follow financial reporting procedures.

- **Depreciation expense adjustments:** Manitoba Hydro is proposing to adopt an approach to depreciation rate calculation that includes, as reviewed in section 7 of this testimony, an element that will substantially accelerate its collection of depreciation expense and impose unnecessarily high costs on today's rate payers without any corresponding increase in benefits related to the underlying assets.

The results of this review indicate that the cash flow issues identified in the GRA will not be substantially addressed by rate increases in excess of inflation, but rather require further diligence in cost controls and a reconsideration of proposed accounting and depreciation changes that aggressively front-load the recognition of these costs by today's ratepayers.

Based on this review, the following conclusions and/or recommendations are provided:

1) The need for rate increases at this time outside the generally accepted range of inflation (that is, between 1 to 3 per cent annually) has not been sufficiently explained and justified to date by Manitoba Hydro. More specifically, the following elements of the Application require review and potential adjustment to reduce the requested rate increases for the test years:

    (i) Changes proposed to capitalization of overheads (to shift costs from capital to O&M) should be reviewed and adjusted as needed to reflect fairly the degree to which ratepayers today versus in the future benefit from these costs. Options to minimize the impact on today's ratepayers caused by recognizing costs that can reasonably be concluded to provide benefits in the future, including those related to supporting capital programs, should be reviewed and considered.

(ii) Forecast new increases in O&M costs, including salary costs, and in non-major capital project costs should be reviewed and only included in test year rates to the extent that such increases are adequately explained and justified.

(iii) DSM spending increases that are simply placeholders, or which do not pass the RIM test, should not be included in test year rates, and the extent to which DSM expenditures will remain the responsibility of Manitoba Hydro on an ongoing basis (and therefore included in rates) should be confirmed.

(iv) Net salvage from depreciation rates should be eliminated as proposed in the Application, as these are not required for ratemaking purposes.

(v) The Equal Life Group (ELG) method of depreciation as proposed in the Application imposes unfair added costs on current ratepayers and therefore should not be adopted, and the Average Service Life (ASL) method should be retained, consistent with other Crown owned and hydro dominated utilities.

2) The Board should recommend that Hydro retain responsibility for planning and delivering DSM programs for industrial customers but monitoring of costs and benefits of DSM programs may reasonably be undertaken by an independent entity.

3) The Board should defer making changes to cap participation in the curtailable rate program and reconsider this issue in the future in the context of fully considered DSM programs and an integrated resource plan.

2.0 CASH FLOW IN RATE SETTING

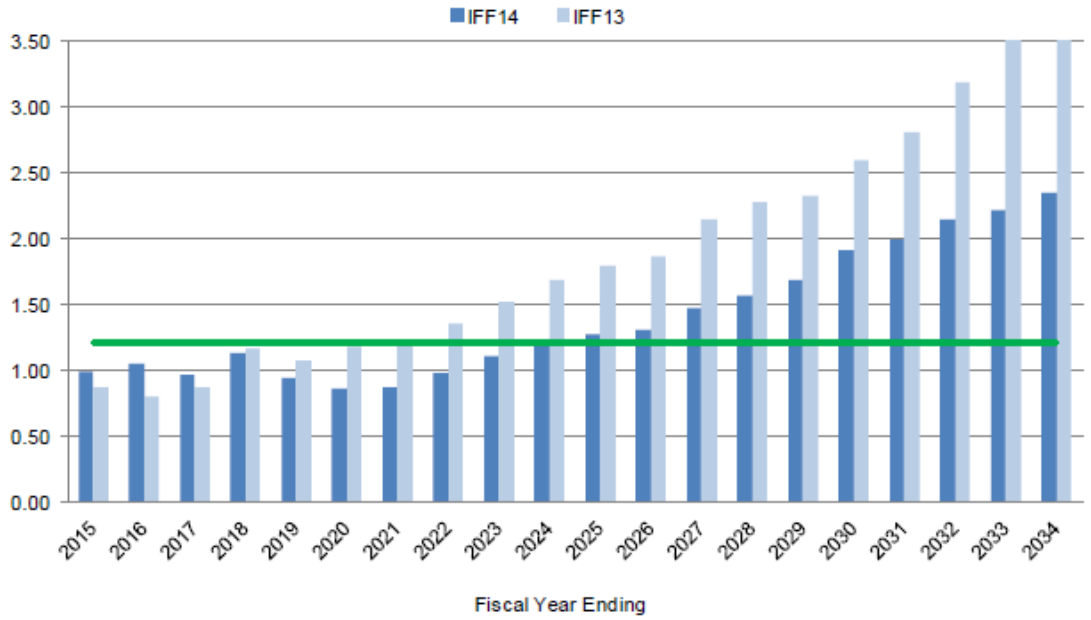
The current Application indicates overall rate increases driven in part by a material change from IFF13 to IFF14 in sustaining capital expenditures.

- As illustrated in Figure 2, the material erosion of Manitoba Hydro's capital coverage ratio (excluding major capital projects) in one year, from IFF13 to IFF14, is striking.

- Manitoba Hydro has historically targeted to fund sustaining capital expenditures with cash flow from operations. However, for the forecast period from fiscal year 2015 to fiscal year 2024, Manitoba Hydro indicates that cash from operations will be sufficient to fund sustaining capital in only four of ten years. As a result, Manitoba Hydro forecasts increased borrowing will be required to fund sustaining capital.

Hydro indicates that the proposed rate increases are necessary to match cash flow requirements to sustaining capital spending needs.[1]

Figure 2: Projected Consolidated Capital Coverage Ratio[2]



Note to Figure 2 - Manitoba Hydro indicates that its consolidated capital coverage ratio target is 1.20 (excluding major new generation and transmission projects).[3]

[1] Application, Tab 2, pages 16-17.
[2] Taken from Figure 15-3 of IFF-14. Appendix 3.3, Page 21.
[3] IFF14. Appendix 3.3, Page 19.

However, Manitoba Hydro's proposed domestic rate increases do little to address this issue within the ten year period from fiscal year 2015 through 2024. It appears this issue is driven substantially by increased spending on non-Major capital and other factors as discussed further in section 6 of this evidence. In any event, if Manitoba Hydro is concerned about the ability to fund non-Major capital projects with cash from operations, it appears that additional spending controls will be required in addition to any increases in domestic revenues.

Figure 2 demonstrates adverse and material change in Hydro's forecasts over the past year. As indicated in the discussion which follows on specific topics affecting the requested rate increases, Hydro's Application has not provided adequate explanation or justification for the level of rate increase requested at this time.

3.0 ACCOUNTING CHANGES & CAPITALIZATION OF OVERHEADS

Hydro is undergoing accounting changes in preparation for an early adoption of International Financial Reporting Standards (IFRS) for April 1, 2015. While Hydro's accounting changes may be appropriate for financial reporting standards, it is important for the PUB to consider whether or not the accounting method changes, which often increase costs in the forecast period and required rates, are appropriate and fair to use to set rates paid by domestic customers today.

It is noted that the continued use of regulatory accounts is commonplace and expected to continue as commented by the Auditor General of British Columbia:

> Recent changes in accounting standards mean that the Canadian Accounting Standards Board (CASB) have allowed rate-regulated entities such as BC Hydro to continue to use rate-regulated accounting beyond 2015. In January 2014, the International Accounting Standards Board (IASB) published an interim accounting standard for rate-regulated entities. This standard allows entities that currently recognize regulatory deferral account balances in accordance with their previous GAAP, to continue to do so when making the transition to IFRS. In April 2014 the CASB adopted this standard, thereby permitting Canadian entities to continue to use rate-regulated accounting beyond 2015. We expect this standard to remain in place for many years while the IASB completes its comprehensive rate-regulation project.[4]

It appears that the interim state of flux for IFRS transition by rate regulated entities may continue for some time. Therefore, the increased standards for capitalizing costs required under IFRS should not be immediately adopted into rates simply because Hydro is early-adopting IFRS for financial reporting. These changes, and the collective magnitude of their effect on intergenerational equity, should be carefully considered and reviewed before lasting determinations are made. The impact of accounting changes also potentially affects the calculation of Manitoba Hydro's financial targets, including its debt to equity ratio as noted in previous proceedings. This leads to further uncertainty about the full magnitude of the proposed accounting changes at this time.[5]

3.1 INCREASE IN OM&A DUE TO OVERHEAD EXPENSES

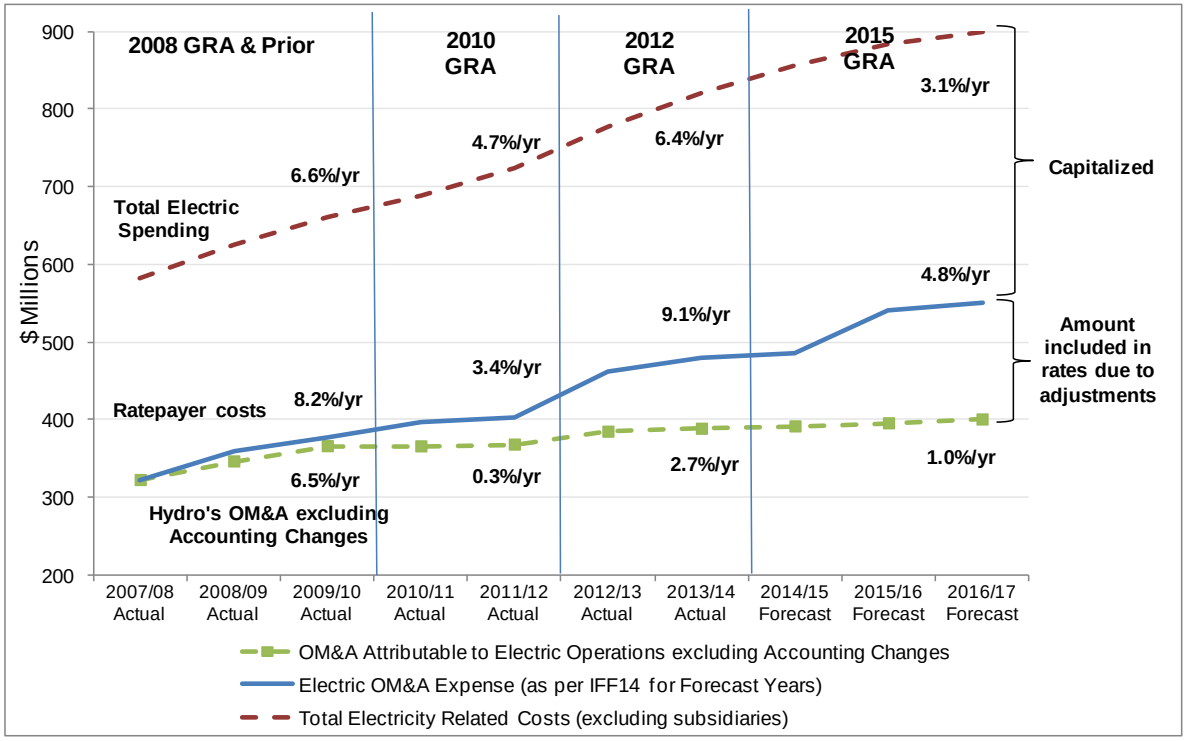
Figure 3 shows actual OM&A from 2007/08 to 2013/14 and forecast OM&A from 2014/15 to 2016/17. The figure shows total electric spending before any capitalization of costs or accounting changes (red dashed line at the top of Figure 3), the total spending per year after capitalized deductions equal to the forecast

[4] Comments made by the Auditor General of British Columbia regarding BC Hydro's continued use of regulatory deferral accounts in the Follow-Up Report: Updates on the Implementation of Recommendations from recent reports. June 2014. Page 9. Accessed online April 21, 2015: https://www.bcauditor.com/sites/default/files/publications/2014/report_19/report/OAGBC%20Follow-up%20Report_FINAL.pdf.

[5] In response to PUB/MIPUG I-23 (a) from the 2010/11 General Rate Application. It was noted that inclusion of accumulated other comprehensive income in the determination of the debt to equity ratio can cause considerable instability in measured equity levels.

amount for OM&A in MH14 (blue solid line in the middle of Figure 3) and OM&A charges excluding cost adjustments due to accounting changes (green dashed line at the bottom of Figure 3).

Figure 3: OM&A Spending Per Year[6]



The OM&A expense attributable to Electric Operations excluding accounting changes is projected to increase by an average of 1% per year from 2014/15 to 2016/17, however, this amount is not representative of what is included in rates. The OM&A expense that rates are based on increases on average 4.8% per year from 2014/15 to 2016/17, driven primarily by an 11.5% increase in 2015/16 related to IFRS accounting changes for administrative overhead.

Table 1 provides a comparison of additions to OM&A as a result of changing accounting policies for capitalization of overheads between IFF12-1 and IFF14-1 and indicates that IFF14-1 includes year over year increases even though:

- IFF12-1 includes Conawapa expenditures that would no longer be able to be capitalized that IFF14-1 does not; and
- IFF14-1 is alleged to include cost containment measures that limit core OM&A expenditure increases to 1%.

[6] Total Electricity Related Costs excluding subsidiaries and capital cost reductions for 2007/08 to 2008/09 from Appendix 4.4 from the 2010 GRA page 14, for 2009/10 to 2011/12 from Appendix 5.6 from the 2012 GRA page 7. Actual and forecast amounts for 2012/13 to 2016/17 from Appendix 5.5 of 2015 GRA page 15. IFRS changes breakdown from Exhibit MH-55 from the 2012 GRA and PUB/MH I-73a from 2015 GRA.

Table 1: Comparison of OM&A adjustments from capitalized Overhead Accounting Policy Changes ($ Millions)[7]

($ Millions)		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
IFF12-1	CGAAP Overhead Capitalized	58	59	60	61	62	64	65	66	68
IFF12-1	IFRS Admin & General		37	38	38	39	40	41	41	42
Total		**58**	**96**	**98**	**99**	**101**	**104**	**106**	**107**	**110**
IFF14-1	CGAAP Overhead Capitalized	61	62	63	63	64	65	65	66	66
IFF14-1	IFRS Admin & General			55	55	56	56	57	57	58
Total		**61**	**62**	**118**	**118**	**120**	**121**	**122**	**123**	**124**

It is important to ensure that expensing these costs to today's ratepayers is fair. The implications of Hydro's early adopter status April 1, 2015 must also be considered. Previous interim standards approved by the IASB for Regulatory Deferral Accounts have been permitted for first-time adopters only.[8] There is a risk that Hydro will not be allowed to apply for any additional interim standards past April 1, 2015 regarding Regulatory Deferral Accounts or other unresolved rate regulation matters.

In assessing these new test year charges for the purpose of setting regulated rates, it is necessary (as in the past) for the Board to ensure that costs are fairly apportioned to customers based on the time periods (years) when the benefits of spending are expected to arise rather than on any suggested need to strictly follow financial reporting procedures.

3.2 EFFECTS ON TOTAL CAPITAL EXPENDITURES

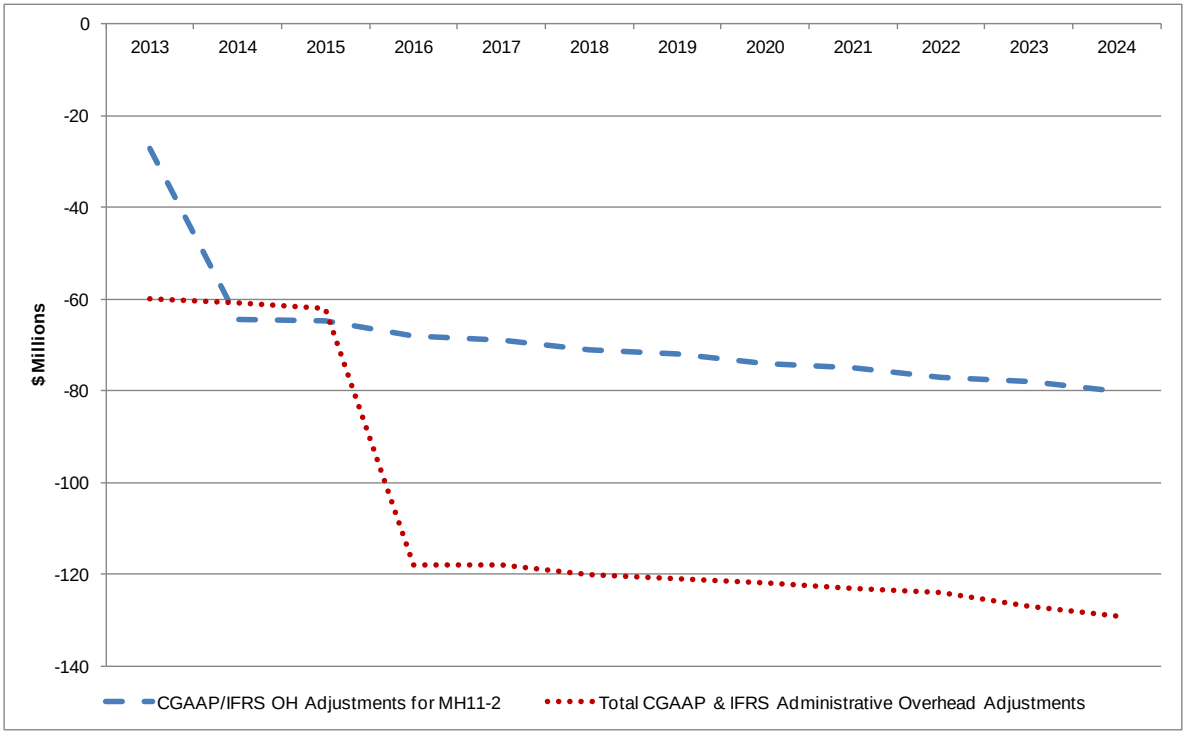
Hydro states in response to COALITION/MH I-28 (e) that the impact of the transition to IFRS is reflected in the current capital expenditure forecast and individual capital projects from fiscal 2015/16 to 2033/34. It would therefore be expected that increases to OM&A due to accounting standard changes should result in overall lower capital expenditure costs, as overhead costs that were previously capitalized are now recognized as expenses in the year incurred. However, Hydro's CEF11-2 adjusted for accounting changes does not appear to reflect this relationship, as shown in Figure 4.[9]

[7] IFF14-1 from PUB/MH I-73a; IFF12-1 from Exhibit MH-55 from the 2012/13 & 2013/14 GRA.

[8] As an example the interim standard for IFRS 14 approved January 30, 2014 by the IASB is permitted for entities that are first-time adopters of IFRS only. Discussed in Appendix 5.4: IFRS Status Update Report, page 19 – 20.

[9] Consistent with Hydro's response to COALITION/MH II-33b, "adjustments for ineligible overheads were made at an aggregate Corporate level to Property, Plant and Equipment for MH11-2 and MH12 and were not captured and reported at the project and business unit level until subsequent CEFs" and are therefore not included in the original CEF11-2 as provided in the 2012/13 and 2013/14 GRA.

Figure 4: Administrative Overhead Adjustments applied to MH11-2 Compared to Total Administrative Overhead Adjustments from CGAAP and IFRS Accounting Changes[10]



On an aggregate level, it appears approximately $55 million of decreased capital expenditures per year due to overheads no longer being capitalized should be reflected in the capital spending forecasts starting in 2015/16.[11] However, instead capital expenditures are forecast to increase from 2014/15 to 2015/16 by 23.1%.[12]

[10] As reported for MH11-2 in Coalition/MH II-33a-b and for Administrative Overhead adjustments to OM&A in PUB/MH I-73a. Data not provided for other IFFs.

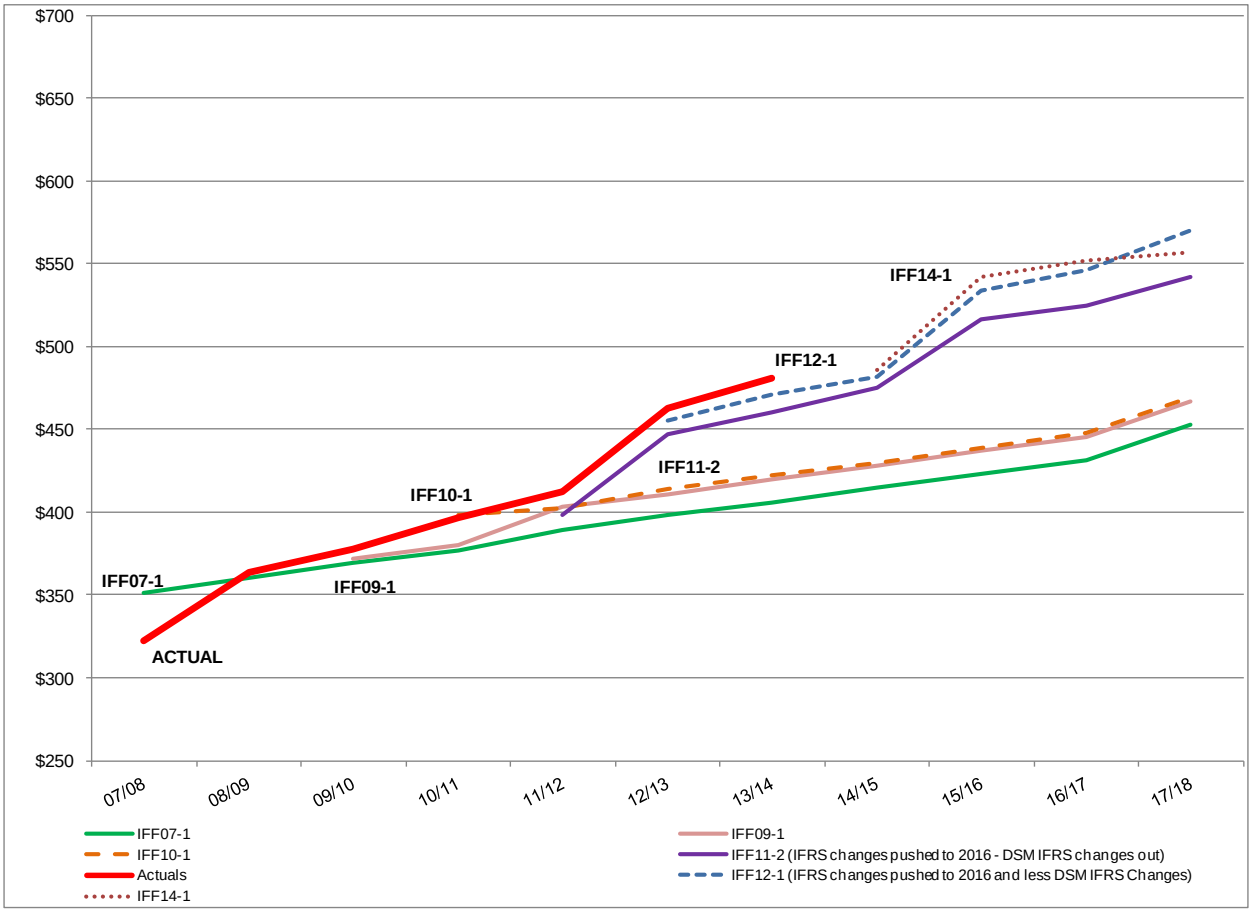
[11] Calculated as $55 million from PUB/MH I-73a divided by forecast 2014/15 Total Electric CEF spending of $2.022 billion from Appendix 3.3, page 33.

[12] Total Electric CEF spending of $2.49 billion in 2015/16 divided by 2014/15 forecast spending of $2.022 billion from Appendix 3.3, page 33.

4.0 OM&A BUDGETING

As reviewed in Figure 5, Hydro's Actual OM&A expenditures have routinely been higher than forecast, and Hydro's OM&A costs in the current filing continue to show sustained growth. Further, forecast OM&A spending in IFF-14-1 continues to be equal or higher to OM&A spending forecasts included in IFF-12-1 until 2017/18. While Hydro asserts that it has implemented cost control measures, there has been no corresponding reduction in overall OM&A costs in the test year relative to previous forecasts.

Figure 5: Forecast OM&A Expense[13]



In response its response to MIPUG/MH I-5, Manitoba Hydro provided an update on its review of budgeting and forecasting procedures to ensure that all programs are cost-justified and that appropriate measures are in place to ensure cost effective operation, stating:

> As part of the IFF14 operating budget process, Manitoba Hydro identified additional measures to manage OM&A expenditures below inflationary levels. The forecast apportioned to each of the business units considered specific business and economic

[13] Forecast expenditures from the respective IFF Electric Operations Projected Operating Statement. Actuals as per PUB/MH I-9a and PUB/MH I-59d of 2012/14 GRA and per Appendix 11.18 (figures do not include subsidiary amounts).

> factors, as well as the various measures needed to support cost containment. In evaluating the appropriateness of the business unit targets an analysis of specific work functions was undertaken, seeking opportunities to streamline processes through the use of technology and consolidation or elimination of work, while balancing the need to ensure staffing levels are adequate to provide safe and reliable service.[14]

Several other information requests also sought information to better understand Manitoba Hydro's internal approach to budgeting and cost controls, including:

- Senior management budget guidance documents;[15]
- Copies of the extensive review completed by Hydro of its staff complement;[16] and
- Information on other targets developed for OM&A cost containment outside of staffing, salaries and wages.[17]

Hydro's responses to these information requests did not provide sufficient information to understand how the budgeting and cost control approaches were implemented in IFF14-1.

Hydro continues to exceed its OM&A forecasts despite its assertions that budgeting and cost control measures have been implemented to contain OM&A expenditures below inflationary levels. Hydro's Application has not provided an adequate explanation or justification for the continued increase in actual OM&A expenditures and why these amounts should be reflected in rates in the test year.

[14] MIPUG/MH I-5, page 5.
[15] MIPUG/MH I-37 (a).
[16] MIPUG/MH I-38(a).
[17] MIPUG/MH II-34 (a).

5.0 STAFFING/EQUIVALENT FULL-TIME EMPLOYEES

Salaries, overtime and benefits represent 77%[18] of OM&A costs incurred by the Corporation and are an important consideration in an overall attempt to control Hydro's costs. In order to set fair and reasonable rates for the forecast period the PUB needs to determine if Hydro has done enough in its treatment of forecast costs and if Hydro has exercised all prudent measures to reduce and contain OM&A growth, which has substantially escalated in forecast and actual amounts in recent years.

Hydro states in its filing that it has committed to a reduction of approximately 300 operational positions, or equivalent cost reductions, in order to achieve the 1% average annual increase in core OM&A costs over the 2014/15 to 2016/17 period. Hydro indicates this will be achieved as a result of attrition, application of technology and the consolidation and elimination of work processes where necessary.[19]

Based on review of the filing, there is uncertainty with respect to how Hydro intends to achieve these targets. The Board should carefully consider the level of salaries and wages it considers appropriate to reflect in rates going forward.

Salaries and Wages

Wages and salaries are projected to grow in each year of the forecast period, on average by 3.5%.[20] Total labour and benefits are also growing each year for operational specific positions, with an actual increase of over 5% seen between 2012/13 and 2013/14.[21] This represents $22.87 million in added costs to ratepayers as a result of increased operational labour & benefits that will be recovered from ratepayers unless actual reductions in Wages & Salaries are realized.

Actual Wages, Salaries, Overtime and Benefits for 2012/13 and 2013/14 were much higher than forecast.[22] Hydro states that higher pension costs are the main reason for the overages, however, this is difficult to confirm.[23] At the same time, the impact of accounting changes to include overheads and other costs that were previously capitalized directly in rates through OM&A expense is growing. Ratepayers are faced with these added costs that Hydro is not including in its target to reduce OM&A.

[18] PUB/MH I-7a.
[19] MIPUG/MH II-34a&b.
[20] Appendix 5.5: OM&A Expense, page 15.
[21] Appendix 5.5: OM&A Expense, page 16. Percentage calculation from $442.6 million actual from 2012/13 to $465.5 million in 2013/14.
[22] PUB/MH I-29a.
[23] PUB/MH I-29a.

Hydro has indicated there are 60 EFT positions previously allocated to Conawapa that are projected to be redeployed within the forecast period (approximately 2015/16). Hydro anticipates that these positions will support either the Corporation's capital investment requirements or address operational priorities and other work demands resulting in less external hires.[24] This should be expected to result in overall lower EFTs in the forecast period; however, it is not apparent how this is reflected in the test year forecasts. Overall, Manitoba Hydro's target of reducing EFTs by 300 positions does not appear to be fully realized in the test year. PUB/MH II-49 suggests these savings will not be fully realized until 2017/18.

Vacancy Rates

Forecast vacancy rates affect the overall level of salaries and wages expense that must be recovered through rates. Hydro is using an average vacancy rate of 4.5% per year to calculate total OM&A salaries and wages (i.e., Hydro forecasts that an average of 4.5% of all positions are vacant in the forecast year).[25] Actual vacancy rates for the company have ranged between 7.4% and 9.3% per year[26] from 2009/10 to 2013/14. As an example, using the lower vacancy rate over the 6,468 total Equivalent Full-Time positions in the 2015/16 year [27] suggests that Hydro is forecasting approximately 291 EFTs will be vacant, while using recent actual vacancy rates would result in forecasts of between 479 to 601 vacant positions per year.

Hydro states in Coalition/MH II-16 that Hydro's forecast vacancy rate is lower than experienced historically due to the need to fill vacant capital positions to support major new generation and transmission development; to replace aging utility assets; and to address increased capacity requirements. Hydro has not provided a reasonable explanation for its forecast lower vacancy rates – until a sufficient explanation and justification is provided, the higher historic vacancy rates should be used and included in rates.

[24] MIPUG/MH II-31.
[25] MIPUG/MH I-6b.
[26] MIPUG/MH I-6c.
[27] Figure 5.5.8 from Appendix 5.5 to the Application, page 10.

6.0 NET PLANT IN SERVICE AND CAPITAL EXPENDITURES

Hydro's Needs For and Alternatives To (NFAT) Review undertaken in 2013 and 2014 mapped out a 78 year future for forecast revenues and expenditures for many different development options. Based on this review the PUB concluded that Manitoba Hydro did not sufficiently justify the construction of the Conawapa Project. The plan that was adopted (Plan 5 with DSM Level 2), and that is now being implemented in IFF14, included:

- Keeyask for a 2019 in-service date;
- the 750 MW Transmission Interconnection for in-service date of 2020; and
- economic DSM with incremental growth at 1.5% to 2% each year.[28]

For the NFAT review 'Plan 5 with DSM Level 2' was modelled extensively and had the following parameters:

- 3.74% rate increases per year projected from 2015/16 to 2031/32 (compared to 4.27% for the same plan with Conawapa – known as the 'PDP' or 'Plan 14 with DSM Level 2') and no increases required thereafter;[29]
- Net Plant In Service by 2031/32 forecast at $23.7 billion, in nominal dollars (compared to $29.5 billion for the same plan with Conawapa)[30]; and
- A debt/equity ratio of 75% by 2031/32 (for both Plan 5 and the PDP plan).[31]

In contrast to the plan reviewed during the NFAT a year ago the above parameters are higher in IFF14 (as reviewed below):

- IFF14-1 has 3.95% rate increases until 2031/32 with 2% rate increases thereafter[32];
- Net Plant In Service for 2031/32 in IFF14-1 $24.6 billion; and
- IFF14-1 Consolidated debt/equity ratio is 79% for 2031/32.

[28] NFAT Review of Manitoba Hydro's Preferred Development Plan – Final Report. June 20, 2014. Page 250-251. Available online: http://www.pub.gov.mb.ca/nfat/pdf/finalreport_pdp.pdf.

[29] Based on the NFAT DSM Analysis – Main Submission Rate Methodology table provided in Exhibit MH-104-12-16.

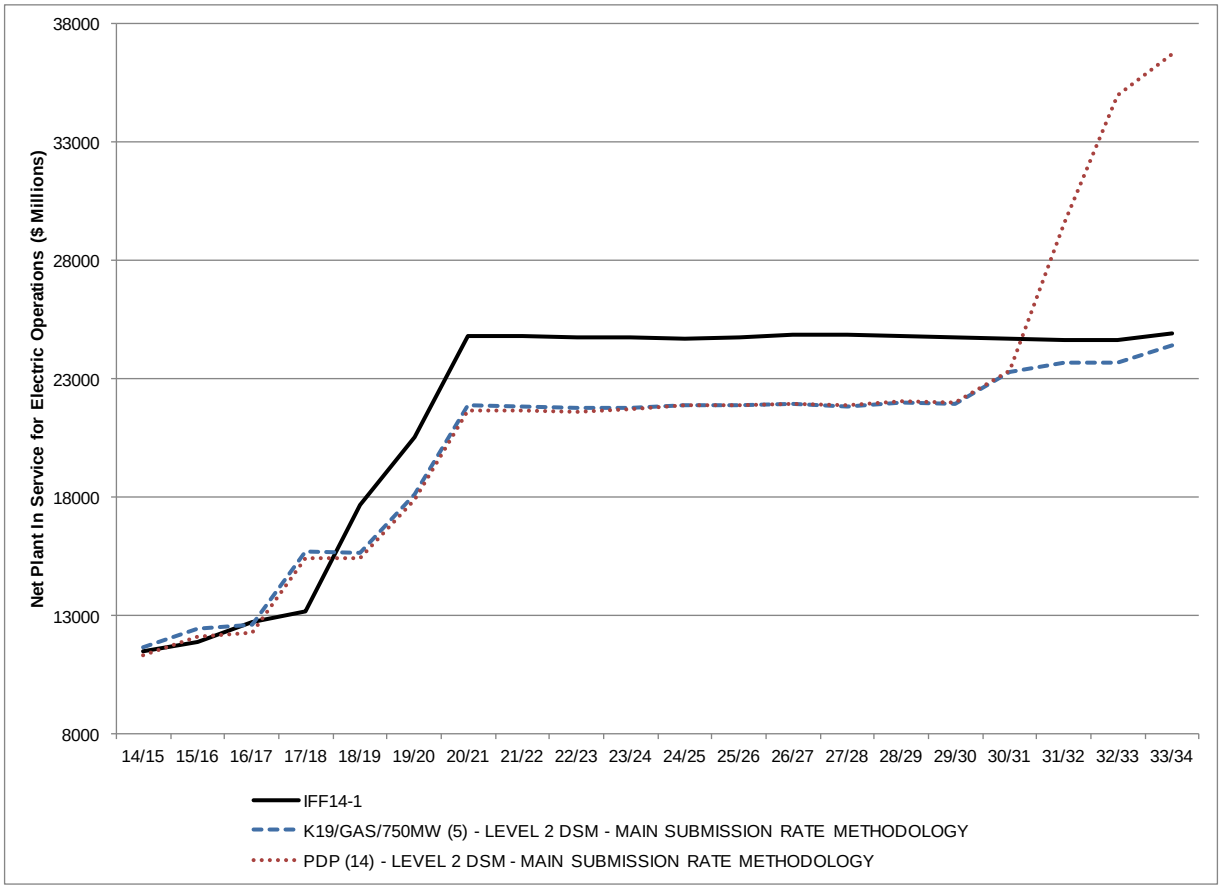
[30] From excel models provided as Exhibit MH-104-12-1: DSM Evaluation Pro Forma Financial Statements during the NFAT review.

[31] Based on the NFAT DSM Analysis – Main Submission Rate Methodology table provided in Exhibit MH-104-12-16.

[32] Appendix 3.3: IFF14, page iv.

Figure 6 shows that forecast Net Plant in Service for IFF14 is higher than the NFAT forecast for the plan with higher DSM and without Conawapa in all years.

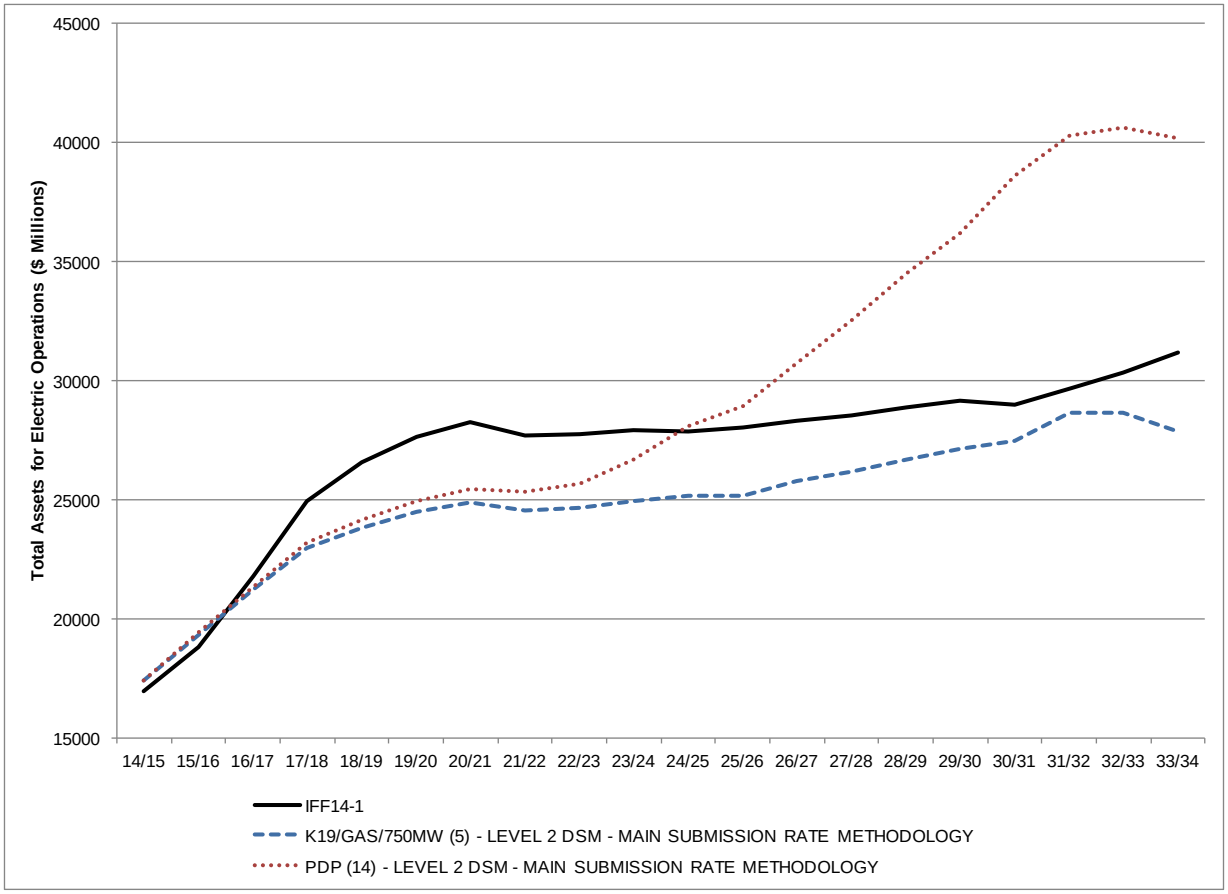
Figure 6: Net Plant in Service Forecast Comparison NFAT with IFF14 ($ Millions)[33]



[33] NFAT data for K19/Gas/750MW and PDP from excel models provided as Exhibit MH-104-12-1: DSM Evaluation Pro Forma Financial Statements during the NFAT review.

Total electric operations assets include net plant in service; current and other assets; construction work in progress; goodwill and intangible assets; and regulated assets. Figure 7 compares total electric operations assets for Plan 5 with DSM Level 2 and IFF14 and indicates that IFF14 is higher than previous forecasts in all years.

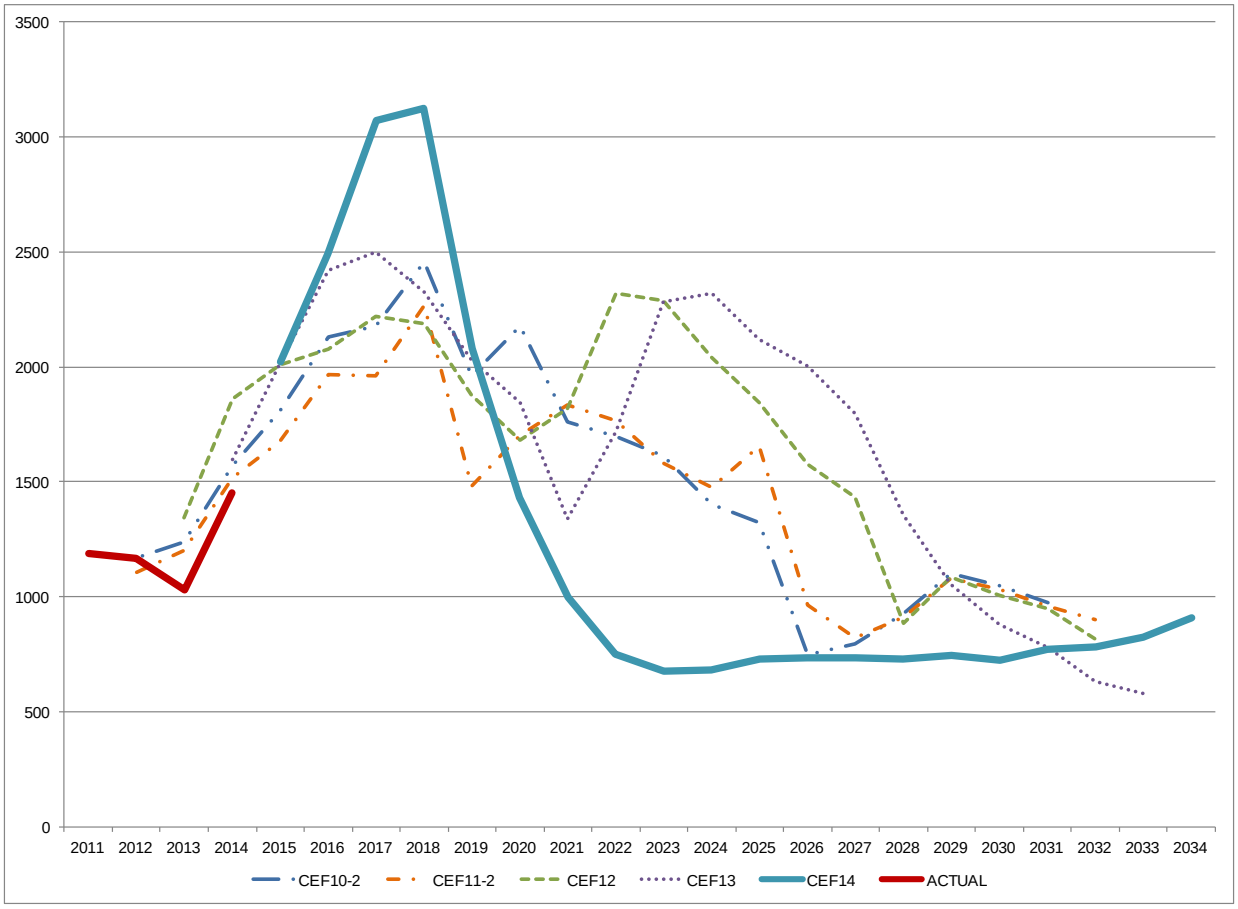
Figure 7: Forecast Total Electric Assets Comparison with NFAT and IFF14 ($ Millions)[34]



[34] NFAT data for K19/Gas/750MW and PDP from excel models provided as Exhibit MH-104-12-1: DSM Evaluation Pro Forma Financial Statements during the NFAT review.

Figure 8 compares total electric capital expenditures for CEF-14 to previous forecasts. The current forecast shows a material increase compared to previous forecasts.

Figure 8: Total Electric Capital Expenditure Forecast ($ Millions)[35]



Both CEF-13 and CEF-14 show increased sustaining capital expenditures relative to previous forecasts in the 2015 through 2020 period, and do not fully explain the increases in net plant in service and electric assets observed in Figure 6 and Figure 7.

Manitoba Hydro explains its procedures for prioritizing capital expenditures in response to Coalition/MH I-11a:

> Manitoba Hydro has in place an overall framework for the evaluation and prioritization of its capital expenditures which supports the Corporations' objectives relating to customer value, safety, protecting the environment, energy conservation, aboriginal relationships and financial strength.

[35] Forecasts from respective CEF forecasts for total electric spending. Actuals from Coalition I-28a for 2012/13 – 2013/14. Actuals for 2010/11 and 2011/12 from IFF10-2 and IFF11-2 CEF total electric spending schedules, as explained in Coalition I-28a the first year incorporates actual capital expenditures for these forecasts.

Based on material provided to date, it is not clear how this framework has been applied or why it has led to such substantial increases in capital spending since the NFAT proceeding. Without a clear and detailed explanation, such substantial changes over such a short time period are troubling. Consequently, the Board should be concerned with whether Hydro has provided sufficient justification to merit recovery of these costs through rates at this time.

7.0 DEPRECIATION

BACKGROUND

In Manitoba Hydro's 2012/13 & 2013/14 General Rate Application, Hydro introduced a new depreciation study for year ending April 30, 2010 prepared by Gannett Fleming with changes to the existing methodology including the adoption of the Equal Life Group (ELG) method. Prior to this study, depreciation costs were based on the Gannett Fleming depreciation study for year ending 2005 that included net salvage and used the Average Service Life (ASL) methodology for depreciating Hydro's asset base, which consists mainly of long-lived hydro and transmission assets.

Hydro filed its 2015/16 General Rate Application, with a new depreciation study, again by Gannett Fleming, for the year ending April 30, 2014. Consistent with the 2010 study, this study again proposes the ELG method for depreciation (changed from ASL), removes net salvage and extends asset service lives (including additionally extending a few other asset lives, mostly smaller assets such as vehicles).

The stated purpose of the both the 2010 and 2014 study is to prepare for conversion to IFRS accounting standards for financial reporting. It is noted that reporting for rate regulation purposes need not strictly follow financial report requirements moving forward; however, Hydro has an aversion to the "two sets of books" solution.

The 2014 study changes the following:

- Change from ASL to ELG methodology – Hydro's rationale is that ELG is more consistent with IFRS due to componentization requirements (i.e., Hydro's historic asset record isn't detailed enough to convert to the level required under IFRS if ASL method continues to be used). The study also states that ELG is more accurate and is more likely to capture the actual service life of individual assets within the larger component class, minimizing the amount of gains and losses recognized on retirement of assets and reducing net income volatility. The change in methodology results in a cumulative increase of $1.238 billion from 2015/16 to 2033/34.[36]

- Removal of Asset Retirement Costs from Depreciation (net salvage) – (unless there is a legal or construction obligation to do so) this is estimated to decrease depreciation expense by $60 million for the 2015/16 forecast year and result in a cumulative decrease of $2.141 billion for the period from 2015/16 to 2033/34.

- Changes to Asset Service Lives – some asset lives were extended for the 2010 depreciation study. The 2014 depreciation study continues with these life extensions and extends the lives of

[36] PUB/MH I-37b.

other assets as well, decreasing depreciation expense by $29 million in 2015/16 and by $746 million cumulatively from 2014/15 to 2033/34.

Manitoba Hydro's position is that, from an overall fairness perspective, the PUB should consider the impacts of the proposed depreciation changes for rate-setting purposes as a whole rather than focusing only on the change to ELG.[37] However, the PUB must primarily concern itself with ensuring the overall approach is principled and reasonable and results in a fair matching of cost profiles and benefits for ratepayers. From this perspective, the onus is to demonstrate that each method change separately is required for rate regulation purposes, that it better matches regulatory rate setting concepts and that it is to the benefit of rate payers.

7.1 EQUAL LIFE GROUP DEPRECIATION METHOD

ELG is Not the Better Method for Setting Electricity Rates for Manitoba Hydro

The Equal Life Group (ELG) approach to depreciation does not match the economic cost curve of long-lived hydroelectric generation assets, a concept imperative to setting fair rates. ELG was originally implemented for use by the telecommunications industry, where technological advances were causing assets to change out quicker than originally anticipated. A solution to this problem was to implement the ELG method to depreciate the lives more quickly in the early years and counteract the effect of unanticipated shorter life spans. Although ELG has become common for US telecommunications companies, several states still maintain ASL for intrastate purposes, essentially keeping 'two sets of books'. Manitoba Hydro's assets are substantially different that those typically held by telecommunications utilities. The highest cost assets of Manitoba Hydro are also the longest lived and if anything have an increasing economic value as they age. Hydro assets are very capital intensive upfront, and in a cost-based revenue system it is important that the costs of these assets matches the intergenerational use, i.e., that they are not overcharged in the initial years in-service.

IFRS Requirements Are Not Determinative For Rate Setting

The PUB has a requirement to set rates that are just and reasonable for ratepayers, that ensure the costs charged in today's rates are used and useful today, and that today's customers are not funding yesterday or tomorrow's electricity bills (see Attachment C for further commentary on relevant ratemaking principles). It is not a requirement that the financial forecasts used to set these rates comply with International Financial Reporting Standards.

[37] Appendix 11.49, page 2.

Concerns with Respect to Componentized ASL are Not Relevant

Hydro's argument that use of ASL under IFRS would require a level of componentization that Hydro does not have the back-up asset data to support is not relevant to rate setting, where the current level of componentization has been adequate to set rates for at least a decade. Further, Hydro's contention that its asset data is not detailed enough is concerning because it likely means there is not enough data to support the need for ELG. Additionally, the cost curves and asset lives detail used in the current depreciation study need to be adequately supported based on actual information of Hydro's assets.

There is no Precedent for Use of ELG by a Peer Utility

Gannett Fleming's response to PUB/MH I-42b provides a detailed list of all utilities in North America who are using ELG, and not one of them is a predominantly hydroelectric utility. It is concerning that Hydro is so adamant about changing to this method of depreciation when it hasn't been proven effective or even relevant to any other electric utility with long-lived assets, especially for rate setting but also for financial reporting purposes. The majority of utilities using this approach are heavy in distribution type-assets or much shorter-lived generation assets and are often private companies with a financial return component within revenue requirement.

Manitoba Hydro's Capitalization Policies & Practices Do not Support ELG Assumptions

Manitoba Hydro's capitalization policies do not match the necessary assumptions that ELG makes to calculate annual depreciation expense. ELG's output rates assume that assets in each component will retire throughout the expected life, some before and some after the average life. However, Hydro's practices do not apply this. For example, during the 2012/13 & 2013/14 GRA hearing discussion between PUB member Mr. Raymond LaFord and Mr. Vince Warden included the following:[38]

> MR. RAYMOND LAFOND: But I think Manitoba Hydro capital -- for instance, a new pole which is replacing an old pole, does capitalize that rather than just call it maintenance, because it's repair -- it's -- it's simply replacing the same thing, correct?
>
> MR. VINCE WARDEN: It depends on – on the circumstances, but if -- if it's due to life expiry, then, yes, we would capitalize the replacement asset. If it was due to a -- a car again running into a pole, then it would be charged against maintenance.

The issue is that ELG in its fundamental design accounts for the early mortalities of assets, which is precisely why the method charges more in the early years of an asset component. But Hydro's policies do not match this. Switching to ELG would double charge ratepayers, once through depreciation and once through OM&A for assets such as poles. This is also a reason why ELG is used predominantly by smaller

[38] 2012/13 & 2013/14 GRA Transcript pages 4585 & 4586 on January 18, 2013.

utilities with distribution type assets; because these utilities have the policies and practices in place to properly track each asset within an ELG component.

7.2 NET SALVAGE

The elimination of net salvage from costs should be accepted because it was not taking into account the inherent economic value associated with hydroelectric sites including dams, generators, etc. Hydro understands the value of these hydro sites and would replace aging hydro assets rather than reset the environment back into green space. Any costs to replace would naturally be assumed into rates as incurred in the form of an addition, not as a gain/loss due to retirement. Net salvage inaccurately added costs to ratepayers today to pay for dismantling that would not occur in the future. If there is a legal or construction obligation to charge net salvage, this will still be done in Hydro's depreciation expense through asset retirement obligation accounts, accepted under IFRS.

Other utilities with gas and coal generators were initially hesitant about increased costs to dismantle as well but are finding that there is inherent value in these sites as many utilities have converted steam plants to gas without going through a massive dismantlement (i.e. they are not as costly as predicted). While there are retirements involved in this process there is no "return to greenfield" process and it has been recognized that the alternative of using a new site along with the land, permits, licensing, rights of way, roads, etc. required are too expensive and not guaranteed. Therefore the reuse of existing sites has become more common.

8.0 DEMAND SIDE MANAGEMENT SPENDING

Following the NFAT review, the PUB recommended that Manitoba Hydro be divested of its responsibilities for DSM and that a regulated independent arms-length entity be established to be responsible for developing and implementing a plan to meet mandated DSM targets. MIPUG has expressed concerns with DSM responsibilities for industry being removed from Manitoba Hydro particularly due to the customized requirements of industry for DSM programs as well as potential issues with the funding of such an entity.

Hydro's DSM costs in the current filing show substantial increases over recent IFF forecasts as shown in Figure 9. Forecast costs of DSM programming have increased even though detailed work on program design is pending a final decision from Government regarding Manitoba Hydro's future role and responsibilities for demand side management.[39] The PUB recommended that there should be accountability and performance measurement in terms of achieving DSM goals and that DSM should be subject to performance monitoring against DSM targets independently on an annual basis.[40]

The lack of review in the interim raises particular concerns with respect to the costs ratepayers are being asked to bear as part of Manitoba Hydro's current rate proposals for the 2014/15 and 2015/16 test years (DSM spending has increased from $25 million per year in IFF13 to $52 and $59 million for 2014/15 and 2015/16 in IFF14). Looking out further, in 2017/18 costs for initiatives such as the fuel choice program and conservation rates[41] are causing further expenditure increases (with spending peaking at $91 million in 2018/19) even though these amounts are just placeholders[42] and these programs are not defined.

Expenses that are not sufficiently defined, explained or justified as economic should not be included in rates.

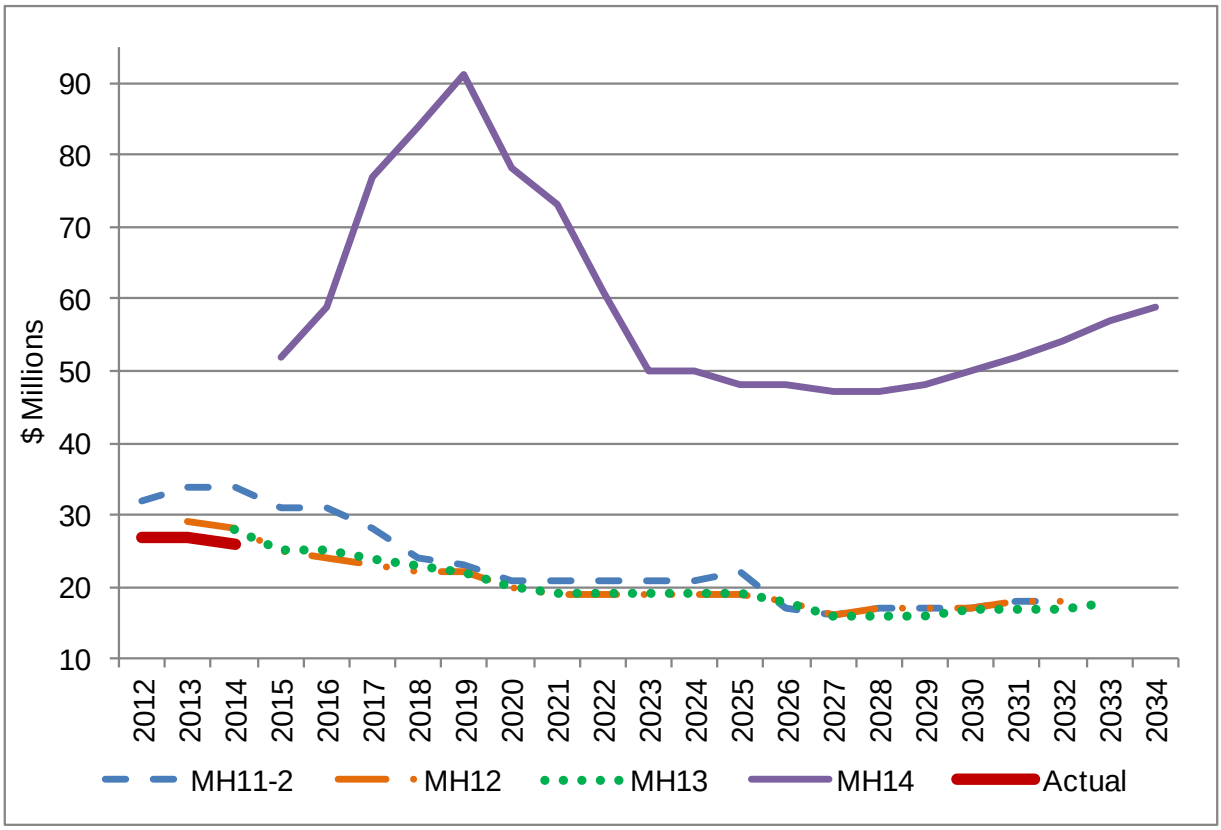
[39] MIPUG/MH I-3(a).

[40] NFAT Review of Manitoba Hydro's Preferred Development Plan – Final Report. June 20, 2014. Page 91-94. Available online: http://www.pub.gov.mb.ca/nfat/pdf/finalreport_pdp.pdf.

[41] As shown in Appendix 8.1: Power Smart Plan, Appendix A.2 for Electric DSM.

[42] MIPUG/MH I-3.

Figure 9: DSM Spending Comparison - Actual and Forecast[43]



The PUB's recommendation to increase DSM following the NFAT review was based on the knowledge that annual average incremental energy savings in the order of 1.5% (including codes and standards) was achievable and economic.[44]

There are concerns, however, that economic evaluations of DSM programs that exclude consideration of lost domestic revenue impacts will overstate the potential benefits of DSM investments. The response to MIPUG/MH I-3(c) demonstrates the degree to which excluding lost revenue impacts can distort the economic valuation of programs such as conservation rates. To ensure fairness in rates the economic profile of DSM requires the consideration of revenue and customer impacts, including non-participating customers, as explained by Mr. Colaiacovo during the NFAT hearing:[45]

> MR. PELINO COLAIACOVO: So DSM programs on an aggregate basis are unambiguously good, I think is one (1) way to put it. The -- and an economically justified DSM program

[43] COALITION/MH I-19g.

[44] NFAT Review of Manitoba Hydro's Preferred Development Plan – Final Report. June 20, 2014. Page 92-93. Available online: http://www.pub.gov.mb.ca/nfat/pdf/finalreport_pdp.pdf.

[45] Transcript page 7478, from the NFAT Review. April 17, 2014. Available online: http://www.pub.gov.mb.ca/nfat/pdf/hearing/april_17_2014.pdf.

> entails the investment of some capital in order to reduce consumption over time, and that reduced consumption benefits the system as a whole.
>
> However, any DSM program will only be taken up by a fraction of participants in the system, and that fraction of the participants in the system will reduce their consumption, and they will pay less for electricity as a result. But other people in the system may subsequently face higher rates as a result of that overall adjustment in demand. And if their consumption has not fallen, they'll still be facing higher rates and they'll pay more.
>
> The total -- the aggregate may have fallen for the entire group, but some people are going to be paying more than others, depending on their participation in the program.

It is important that economic DSM tests, including RIM and PACT, are measured to ensure that customers who choose not to participate in the DSM program being measured are not subsidizing customers who do participate in the program. Customers may not be participating for valid reasons including not being able to afford it, ineligibility or other priorities. If a DSM program fails the RIM test customers who do not participate in the program, regardless of the rationale for doing so, are subsidizing the customers who do participate in rates.[46]

For a program to pass the RIM test the Present Value of Utility Marginal Benefits (the numerator of the ratio) must be greater than or equal to the Present Value sum of Revenue Losses, Utility Program Admin Costs and Incentives (the denominator of the ratio). Therefore a RIM metric should be equal to or greater than one.[47] Hydro's current DSM program forecast for Electric DSM shows a number of residential and commercial programs with a RIM test less than one, meaning that customers that do not or cannot participate will be subsidizing these programs for customers that do while programs for Industrial customers are predominantly valued as economic.[48]

There is also cause for concern that industrial customer focused DSM programming must be developed and implemented through detailed understanding of the unique operating circumstances of each customer. A tailored approach is generally required that requires experience with each individual customer and access to utility data that is customer specific and therefore potentially commercially sensitive. Manitoba Hydro, working with industrial customer, remains best positioned to develop and deliver appropriate industrial customer DSM programming.

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[46] Presentation to the Southeast Energy Efficiency Meeting (part of the Regional Implementation Meetings of the Clean Energy Program of the US EPA), September 28, 2007 by Stan Wise, Commissioner of the Georgia Public Service Commission. http://www.epa.gov/cleanenergy/documents/suca/se-sep-07_wise.pdf.

[47] As defined in Appendix 8.1: Power Smart Plan, Appendix E – Program Evaluation Criteria.

[48] Appendix 8.1 Power Smart Plan, page 42.

9.0 CURTAILABLE RATE PROGRAM

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

9.1 PROPOSED CHANGES TO THE CURTAILABLE RATE PROGRAM

In Board Order 43/13 the PUB ordered that Hydro's proposed changes to the Curtailable Rate Program be approved on an interim basis, to be reviewed by the Board at a General Rate Application to follow the Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.[49]

Hydro's 2012/13 and 2013/14 GRA requested the following key changes to the Terms and Conditions of the Curtailable Rates Program (CRP):

- 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 customer load converts to Option A. Should the Option C customer 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[50], but no practical savings compared to the actual pay-outs in 2011/12 given the programs were not fully subscribed.

[49] Order 43/13 from April 26, 2013. Page 5.

[50] 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.

Following Order 43/14 Hydro implemented all changes on an interim basis except for the following, as they are difficult to implement on an interim basis:[51]

- A change in the defined hours for peak and off-peak periods; and
- Elimination of Curtailment Options "C" and "CE" effective one year from PUB approval (i.e., the sunset date).

Hydro's Proposed Terms and Conditions in Appendix 6.10 do not request any changes since the last revision, filed on July 6, 2012 for the 2012/13 & 2013/14 GRA. The current GRA is requesting the final approval to these CRP changes.[52]

9.2 FAILURE TO RECOGNIZE ONGOING VALUE OF CURTAILABLE RATES PROGRAM

The proposal to eliminate Option C is reasonable given it has been concluded by Hydro to be of limited practical value.[53] The proposals to reduce the caps on the availability of Options A and R should not be adopted.

During the NFAT Review, the Board noted that curtailable load is particularly valuable to Manitoba Hydro in system emergencies and its greatest value is during times of peak power use. Mr. Dunsky explained that there is considerable opportunity for Manitoba Hydro to achieve capacity savings through a combination of new demand response initiatives, energy-focused DSM initiatives, and Manitoba Hydro's current industrial Curtailable Rate Program. MIPUG supports continued participation in the CRP as the program provides capacity, helps with reliability and is one of the few DSM program options available to industrial customers.[54]

Following the NFAT review, the PUB recommended that DSM programming be increased in an effort to decrease future new generation resources, and that the Curtailable Rate Program specifically has the potential to result in additional capacity savings and merits further review.[55] The Minister accepted all of the PUB's recommendations including the recommendation on the Curtailable Rates Program.[56]

[51] Appendix 6.9 to Hydro's current GRA.
[52] MIPUG/MH I-27.
[53] 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.
[54] PUB Final Report on the NFAT. June 20, 2014. Page 86-87.
[55] PUB Final Report on the NFAT. June 20, 2014. Page 94.
[56] MIPUG/MH I-29b.

Manitoba Hydro responded to MIPUG/MH I-29a that an internal review had been undertaken with the conclusion that additional curtailable load in the form presently available under the CRP would only add to the existing surplus capacity and would not generate additional income or cost savings for Manitoba Hydro. Hydro continues to evaluate the CRP to review opportunities and benefits for this program and other related demand response initiatives.

Hydro ascertains 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".[57] 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.[58]

Hydro's narrow timeline for reviewing potential benefits of the CRP does not match the long-term costs that customers make to the program, 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. This matching of benefits with costs is a fairness principle in rate setting that should also be implemented for the review of energy efficiency programs.

Manitoba Hydro continues to fail to recognize long-term value in the CRP. 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.

Given that the current state of DSM programming and responsibility is currently in flux and that an Integrated Resource Planning process is in the beginning stages of development it would be short-sighted to cap the Curtailable Rate Program. The CRP offers long-term reliability and added capacity to Hydro's system that can be used in a cost effective manner to the benefit of Hydro's system and customers. The PUB should not finalize the capping of the CRP because Hydro's current review fails to recognize the very real benefits this program can provide.

[57] PUB/MH I-141(a) from the 2012/13 & 2013/14 GRA provided as Attachment 2 to MIPUG/MH I-30a.

[58] As stated in PUB/MH I-52c and COALITION/MH I-59a customers have shown interest in opportunities to participate in the CRP.

ATTACHMENT A: RESUME

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 and rates, economic analysis and environmental licencing, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in six Canadian provinces and territories. 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 including General Rate Applications and most recently the Needs For and Alternatives To (NFAT) review. 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. Provide advice on interventions in respect of major new transmission facilities. 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.

- **For Municipal Customers of City of Calgary Water Utility (2012-2013),** analysis of proposed new development charges and reasonableness of water and wastewater rates.

- **For Nelson Hydro (2013-current),** development of a Cost of Service model.

- **For City of Swift Current (2013-current),** utility system valuation approach.

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 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. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

- **For Northwest Territories Power Corporation (2010-current),** 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. Provide economic and rate analysis of potential major transmission build-out to interconnect to southern jurisdictions. Conduct business case analysis for regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

- **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.

ATTACHMENT B: 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, Hydro's Major Capital Projects in 1990 and most recently in the Hydro's Needs For and Alternatives To (NFAT) review.

MIPUG membership currently includes the following companies:

- 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[59]. According to the information available at the time the 2012 economic impact study update was undertaken[60], 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;

[59] 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.
[60] The 2012 Economic Impact of the Manitoba Industrial Power Users Group was filed in the 2012/13 & 2013/14 General Rate Application in response to PUB/MIPUG I-1a.

- 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; and

- 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[61] 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)[62]. Since that time, the unrealistic load growth forecasts have been moderated (with gross firm energy forecasting total domestic energy growth over the entire forecast period from 2014/15 to 2033/34 at approximately 7 TWh without Power Smart programs and less than 5 TWh with Power Smart Programs),[63] 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.

[61] 1 TW.h is 1,000 GW.h.

[62] 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.

[63] Tab 7 – Electric Load Forecast, page 6.

ATTACHMENT C: 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.

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;[64] or 3) based on regulated cost-of-service approaches, such as in British Columbia, Yukon, Northwest Territories, Newfoundland, and Nova Scotia.[65]

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[66] ("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);[67]
- 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"); and

[64] This approach is also similar to that used by other non-electric utilities such as many Canadian water and sewer services.
[65] In some cases, only a portion of the respective utility's rates or tolls are regulated based on cost-of-service principles.
[66] See, for example, Bonbright, J.C., 1960, "Chapter IV – Cost of Service as the Basic Standard of Reasonableness".
[67] Charles F. Phillips, The Regulation of Public Utilities (3rd. ed,) at pp. 340.

- 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").

<u>Revenue Requirement and the Used and Useful Test</u>

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:[68]

(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;

(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"),[69] 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

[68] The *Crown Corporations Public Review and Accountability Act*, Part IV, Public Utilities Board Review of Rates, Section 26 (2).

[69] 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.

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".[70]

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.

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.

"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,[71] for a

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

[71] Based on the projected 2013/14 interest rate of 4.05% plus 1% guarantee fee.

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).[72]

- **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 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

[72] At approximately $12 million per percentage point of rate increase.

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.[73] 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[74] who took on the costs and risks related to major generation and transmission developments (both one-time investment risks, as well as ongoing risks related to water flows, plant performance, etc.). In this regard, the generation and transmission resources currently in place (the "bulk power" system) represent the entitlements of ratepayers to attractive and stable electricity prices. Export revenues have been integral to this policy approach, in that the ability to export power enables development (and in some cases allows advancement of development) of large northern hydro stations, in excess of what would be required for solely domestic requirements at any given point in time.[75] 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,

[73] 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.

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

[75] 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.

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.

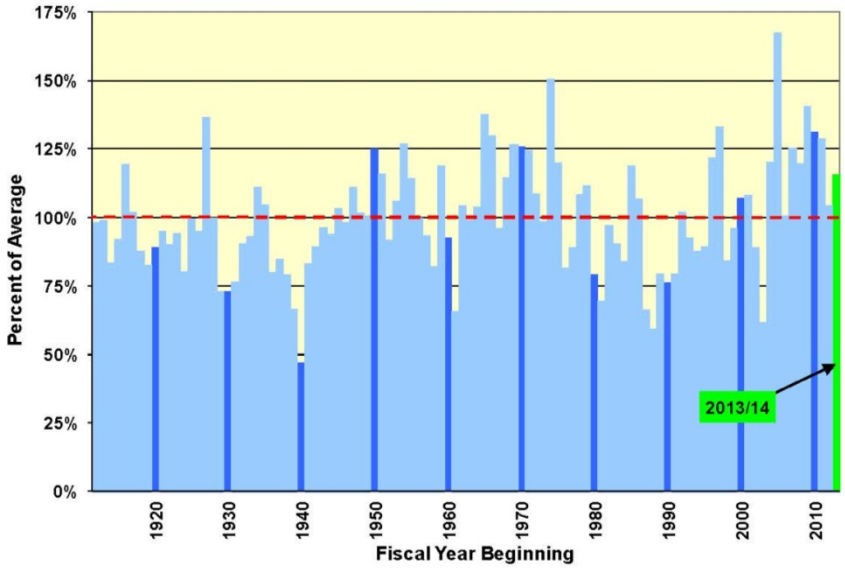
The Role of Reserves

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 more so 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).[76] Many Crown utilities (both electrical and other) have operated for long periods with little to no "equity".

Despite this lack of clear guidance, it is clear that Hydro requires relatively substantial reserves. Hydro's chart at page 18 of Tab 9 is reproduced below as Figure C-1 to illustrate the degree of water flow variability inherent in its system.

[76] 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.

Figure C-1: Historical Water Supply: System Inflows[77]



The chart in Figure C-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 C-1 are portrayed in MIPUG/MH I-9, as shown in Figure C-2 below.

[77] Figure 9.10 Historical Water Supply from Tab 9: Energy Supply from Hydro's 2015 GRA, page 18.

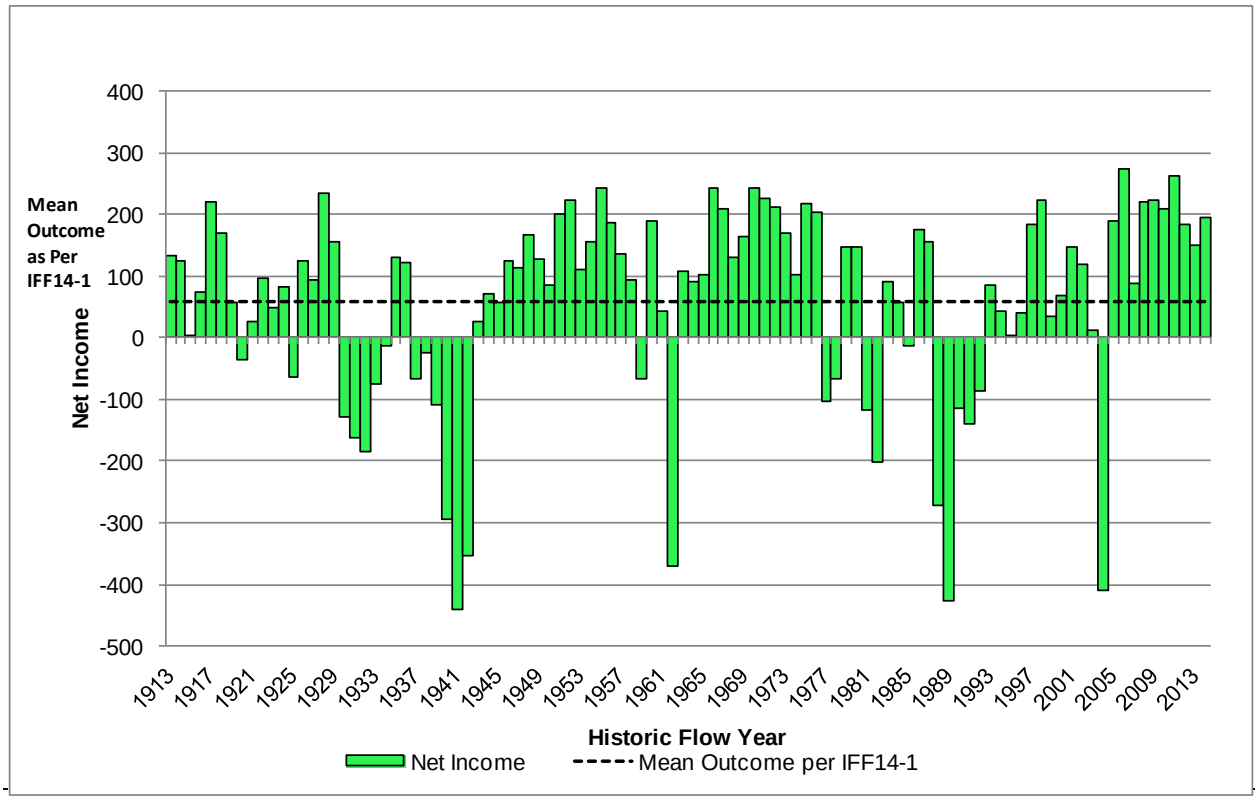
Figure C-2: Financial Implications of Flow Variability

Flow Year	Annual System Inflow	MH Hydraulic Energy	Net Revenue	Variation of Net Revenue from Average
	Kcfs	(TWh/yr)	(M $Cdn)	(M $Cdn)
1912/13	112	32.9	226	74
1913/14	119	32.6	217	66
1914/15	98	28.3	95	-56
1915/16	105	30.4	165	13
1916/17	137	36.2	312	161
1917/18	119	34.1	261	110
1918/19	105	29.9	148	-3
1919/20	98	27.4	57	-95
1920/21	103	29.1	119	-32
1921/22	114	31.5	188	37
1922/23	106	29.6	140	-12
1923/24	112	31.1	175	23
1924/25	99	26.7	28	-123
1925/26	120	32.6	217	66
1926/27	111	31.2	185	33
1927/28	155	37.5	325	174
1928/29	114	33.6	248	97
1929/30	87	25.1	-37	-189
1930/31	89	24.5	-69	-221
1931/32	87	24.0	-94	-245
1932/33	95	26.4	18	-134
1933/34	101	27.8	79	-72
1934/35	119	32.7	222	70
1935/36	118	32.4	213	62
1936/37	96	26.6	25	-127
1937/38	99	27.7	69	-83
1938/39	89	25.6	-16	-167
1939/40	79	22.3	-203	-354
1940/41	55	20.2	-349	-500
1941/42	92	21.5	-261	-413
1942/43	101	29.0	117	-35
1943/44	108	30.7	163	11
1944/45	107	30.4	149	-2
1945/46	119	32.5	216	64
1946/47	113	32.2	205	54
1947/48	126	34.0	258	107
1948/49	113	32.9	219	67
1949/50	116	31.0	176	24
1950/51	144	35.7	293	141
1951/52	132	36.4	315	164
1952/53	107	32.1	202	51
1953/54	124	33.6	248	97
1954/55	143	37.3	335	183
1955/56	133	35.5	279	128
1956/57	119	33.1	228	77
1957/58	111	31.6	186	35
1958/59	96	26.6	26	-125
1959/60	137	34.9	282	130
1960/61	102	29.6	135	-16
1961/62	75	21.4	-278	-430
1962/63	119	32.1	201	49
1963/64	111	31.0	183	31
1964/65	113	31.6	193	41
1965/66	157	37.2	334	183
1966/67	151	36.2	300	149
1967/68	115	33.1	223	71
1968/69	133	33.9	256	105
1969/70	148	37.8	335	184
1970/71	145	36.8	319	168
1971/72	139	36.1	305	153
1972/73	126	34.8	261	109
1973/74	115	31.8	195	44
1974/75	164	36.7	310	158
1975/76	139	36.0	296	145
1976/77	92	26.1	-12	-163
1977/78	99	26.5	26	-125
1978/79	122	33.2	238	86
1979/80	135	34.0	239	88
1980/81	93	25.4	-24	-176
1981/82	85	23.7	-110	-262
1982/83	115	31.6	183	32
1983/84	110	30.0	150	-2
1984/85	101	27.9	80	-72
1985/86	136	34.5	267	116
1986/87	125	34.3	249	97
1987/88	82	22.7	-181	-333
1988/89	72	20.4	-334	-486
1989/90	91	25.5	-22	-173
1990/91	85	25.0	-47	-198
1991/92	91	26.2	7	-144
1992/93	115	31.3	177	26
1993/94	106	29.9	136	-16
1994/95	102	28.8	96	-55
1995/96	103	29.5	133	-18
1996/97	141	35.2	275	123
1997/98	151	36.6	316	165
1998/99	106	30.2	127	-25
1999/00	110	30.7	160	9
2000/01	126	33.3	238	87
2001/02	126	33.2	210	58
2002/03	104	28.7	104	-47
2003/04	72	20.9	-317	-468
2004/05	141	34.7	281	130
2005/06	175	38.5	366	214
2006/07	113	31.9	179	27
2007/08	150	36.6	313	161
2008/09	141	36.7	315	164
2009/10	151	36.3	300	149
2010/11	162	38.4	355	204
2011/12	153	35.7	277	125
2012/13	121	33.4	242	90
2013/14	134	35.7	287	135
Average	**116**	**31.1**	**151.43**	**0**

The values shown in Figure C-2 reflect the financial impact on a given year from the flow variation shown in Figure C-1; that is, 'if the historical water flows repeat themselves with today's system (and using the 2014 Load Forecast) 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 reflected in Hydro's Integrated Financial Forecast including export revenue, water rentals & assessments and fuel & purchased power. In simple terms Net Revenue serves as a rough approximation of the net income that would arise in fiscal 2016/17 with the

noted flow event.[78] 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 1938 to 1942 five year drought flow sequence, reserves would be drawn down by $1,220 million[79] (not including compounding interest impacts), as shown below in Figure C-3.

Figure C-3 (REVISED): Variation of Flow Related to Net Income for 2016/17 ($ Millions)



It is important that Hydro have reserves to at least the level of the net loss arising during severe droughts shown in Figure C-3 to sufficiently protect ratepayers. Comparable numbers for the 1988-1992 period is a drawdown of $1,037 million. These are the worst two instances in the historic record shown.

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

[78] The mean "Net Revenue" of all flow sequences, considering the noted factors, is $151.43 million. The forecast net income in 2016/17 is $59 million as seen in IFF144 Page 36, meaning that the sum of all non-flow related revenues and costs is net negative $92 million. A more precise approximation of net income for the fiscal year means that this net negative $92 million from non-flow related items.

[79] The summation of the values shown as Net Revenue for those five years, less $92 million/year for non-flow related transaction.

aggregate), the largest of which remains major infrastructure failure and drought.[80] 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.

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.

[80] See, for example, CAC/MH II-38(a) from the 2012/13 & 2013/14 GRA.