PRE-FILED TESTIMONY OF

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IN REGARD TO MANITOBA HYDRO 2017/18 & 2018/19

GENERAL RATE APPLICATION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

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1.0 INTRODUCTION

This testimony has been prepared for the Manitoba Industrial Power Users Group ("MIPUG") by InterGroup Consultants Ltd. ("InterGroup") under the direction of Mr. Patrick Bowman. The qualifications of Mr. Bowman are provided in Attachment A. MIPUG's current membership and concerns are outlined in Attachment B.

This testimony complements two other filings being made on behalf of MIPUG:

- Pre-filed testimony prepared by Cam Osler and InterGroup and Gerry Forrest of Forkast Consulting, reviewing Manitoba Hydro's new financial goal to recover a 25% equity level by 2026/27.
- A series of three Background Papers, prepared by Mr. Bowman in support of both this testimony and the testimony of Mr. Osler and Mr. Forrest, covering:
  - Manitoba Hydro Debt Levels,
  - An update on conditions since the NFAT Review, and
  - Manitoba Hydro's Uncertainty Analysis and Risk Scenarios.

In addition, MIPUG is co-sponsoring the evidence of Pelino Colaiacovo from Morrison Park Advisors regarding capital markets perspectives on Hydro's debt and borrowings. As a result, capital market considerations are only briefly addressed in this submission.

For this Pre-filed Testimony, InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's ("Hydro" or "MH") General Rate Application ("Application" or "GRA") for 2017/18 and 2018/19 test years that are of interest to industrial customers.

The scope of review for this pre-filed testimony focuses on the following broad areas:

1) **Revenue Requirement** (overall rate changes)

   a. **Does the evidence support the claim that a move to 7.9% annual increases, compared to the previous 3.95% annual increase forecast, is needed or beneficial**? The merits, if any, to the current GRA seeking a 7.9% rate increase for April 1, 2018 and expected 7.9%/year for 5 further years thereafter, tied to a new outlook and attitude regarding Hydro's financial condition and rates.

   b. **Is a 3.95% annual increase needed in 2017/18?** The necessity and sufficiency of Hydro's previous long-term rate increase of 3.95% for April 1, 2018, as represented by a 3.95%/year rate increase scenario as set out in PUB/MH I-34 Attachment 2 (referred to

"MH16 Update with Interim and MH15 Rate Increases"). This scenario is largely consistent with the types of annual rate increases that have been considered since at least IFF09[1] (November, 2009) including the detailed review that occurred at the Needs For and Alternatives To (NFAT) hearing in 2013-2014. Review of this issue includes assessment of a number of detailed matters related to revenue requirement, such as implementation of regulatory deferrals and individual spending assumptions.

2) Cost of Service and Rate Design

a. **Does the filed Cost of Service study (PCOSS18) reflect proper implementation of the recent Cost of Service Order 164/16?** Also, for those matters where further update or study was recommended, has Hydro properly arrived at conclusions and properly applied the conclusions in PCOSS18.

b. **What does PCOSS18 indicate about the rates for each class, and does PCOSS18 indicate a need for different rate increases among the classes?**

c. Has Hydro proposed a reasonable rate design for industrial customers?

1.1 SUMMARY OF CONCLUSIONS

1.1.1 Overall Rate Increases

Hydro's application proposes rate increases that are significantly above previously considered levels by this Board. The justification for these increases is tied to Hydro's view of its financial position.

The conclusions and recommendations in this submission revolve around three main questions:

1) **Does the evidence support the claim that a move to 7.9% annual increases, compared to the previous 3.95% annual increase forecast, is needed or beneficial?** (Section 4)

- Hydro's support for 7.9% appears largely predicated on three benefits that this rate increase will yield: Maintain Hydro's self-supporting status, serve customer interests, and protect the Government of Manitoba. On each of these topics, Hydro's proposals are not in the public interest.
- The evidence filed does not support the need for 7.9% increases to **maintain self-supporting status**. Using 3 different definitions provided in the evidence (Hydro's definition, KPMG's, and the credit ratings agencies'), Hydro fulfills all of these tests with only one limited exception. The exception is the tests applied by S&P, which Hydro

[1] Appendix 5.2 from Hydro's 2010/11 and 2011/12 GRA, which included 3.5% rate increases annually starting with the major new project development period of 2012/13.

indicates it does not intend to attempt to pass, so is not relevant to rate-setting. For the remaining tests, a scenario consistent with the recent pattern of rate increases (such as 3.95%) is more than sufficient to meet the key criteria. Central to this finding is that regulatory certainty, continuity and transparency is important. Concerns exist that Hydro's proposals reflect instability, a lack of transparency and, most notably, a lack of continuity in ratemaking, which may serve to undermine the perception of Hydro's regulatory risks.

- Hydro's submission regarding the 7.9%/year increases being in the **customer interest** is not supportable. Customers, and the Manitoba economy in which they operate, do not see benefits from rates being higher than otherwise required. There is no indication that customers will be harmed by unstable rates in future if a 7.9% increase is not granted, as evidenced by the detailed uncertainty analysis (also see Background Paper C). Finally, Hydro asserts that customers would benefit in the long-run from the trade-off of imposing 7.9% rate increases now for ultimately lower rates later. Not only is this assertion highly speculative, it is also not a net benefit to customers in most cases where customers face a cost or value of capital that is higher than Hydro's borrowing costs (which is almost universally true given the Province's debt guarantee). Finally, such lower rates would only arise to the extent customers had already funded reserves far above that required to address identifiable risks. In the event that financial benefits are ever targeted into lower rates – materials from Hydro's Board of Directors indicate other priorities (such as dividends to Government or funding new major capital) may instead take precedence at that time. In terms of Hydro's customers' broader interests, Hydro's proposals do not provide any considered analysis regarding impacts on the Manitoba economy. Not only does this cause question for whether the 7.9% proposal will in fact yield the revenues Hydro has projected, it also causes concerns that the Boston Consulting Group materials provided to Hydro's Board, which noted that large industry has "higher risks of shutdown/job loss" under large rate increases, were ignored.

- In regard to **protecting the Province of Manitoba** finances, there is no indication that Hydro debt is causing the Province to face higher borrowing costs. If anything, Manitoba's spread over other provinces (Ontario) has decreased in recent years. In addition, even if higher borrowing costs for the Provincial Government were occurring, there is no indication that the costs to the Province exceed the $230 million/year scheduled to be paid by ratepayers in "debt guarantee fees" once Keeyask is in service, much less the $1.3 billion paid from 2002 to 2017 when there were no net costs to the

Province of having provided the guarantee. In addition, Hydro has not provided any information to indicate the likely adverse impact on the Province's finances from removing $3.6 billion in higher electricity bills from the economy over the next 10 years (plus the added GST and other tax burdens). Concerns arise that reduced economic activity, and related reduced provincial revenues, may exceed any hypothetical protection of the province by advancing Hydro's debt repayments.

- Hydro's "view" regarding paying down debt and building shareholder's equity is inconsistent with Hydro's history of debt management since at least 1980, with the fundamental framework of the *Manitoba Hydro Act*, and with normal regulatory principles on multiple fronts (including rate stability, the used and useful standard, and the basic purpose of resource planning proceedings) (also see Background Paper A).
- In summary, this evidence advises against the Public Utilities Board approving Hydro's proposals for 7.9%/year rate increases.

2) **Looking to scenarios with a 3.95% annual rate increase (notably PUB/MH I-34 Attachment 2), do the scenarios continue to show expected and/or acceptable financial performance?** (Section 5)

- Scenarios using rate increases within the recent range (e.g., 3.95% over the long-term) show financial performance that is better than any recent IFF, as well as NFAT projections, to 2023/24, in terms of costs and revenues.
- After 2023/24, the latest projections show that ratepayers will face moderately higher unit costs than the reference ('REF') case from the NFAT, but still well within the range of LOW and HIGH sensitivity scenarios considered at the time. A significant part of the deterioration from the REF case arises from Hydro's failure to properly implement the Board's directives on depreciation and Integrated Resource Planning (see below). In addition, this cost impact after 2023/24 is coupled with retained earnings levels that are higher than the NFAT forecast range throughout, with a minimum equity percentage under today's forecasts at $2.9 billion. Even NFAT's most advantageous financial forecast scenarios did not exceed $2.6 billion for 10 years after the major projects were in-service.
- Finally, Hydro's new and beneficial Uncertainty Analysis shows that risks today and going forward are materially reduced compared to even IFF14 (and much less compared to NFAT) as more of the capital costs and borrowings for the major capital program are locked-in at historically low long-term interest rates. In particular, the Uncertainty Analysis shows the $5^{th}/95^{th}$ percentile confidence interval to 2021/22 (the

range of net income that could be experienced in 2021/22) with a range of $1 billion in IFF14. By IFF16 this potential variability in net income has declined to $600 million in 2021/22.

- In terms of cash flow, the current forecasts show that even with the lower sequence of rate increases than Hydro's proposed, the full 10 year IFF scenario meets or exceeds the Capital Coverage target of 1.2, indicating that Hydro's cash flows are more than sufficient to fund all corporate financial outflows (including funding all "sustaining" capital) once the major capital project spending winds down following 2022/23, and in fact begin progress on reducing debt (a 1.0 Capital Coverage ratio would indicate debt-neutrality). This is a positive financial condition for the challenging years immediately following the in-service of one, much less three, major new projects.
- The proposal to lower Hydro's weighted average term to maturity is advisable and necessary to achieve appropriate cash management. The savings that are generated are beneficial, and are appropriately included in the financial forecast, including under scenarios with increases on the order of 3.95%/year, not just 7.9%/year.
- In summary, the financial outcomes shown in the projection in PUB/MH I-34 Attachment 2 represent, at minimum, a financial condition that should be viewed as acceptable, if not generally positive.

3) **Are the specific assumptions and inputs used in the PUB/MH I-34 Attachment 2 scenario reasonable? If not, is there a basis to achieve the same financial performance with a different rate increase in 2018?** (Section 6)

- The assumptions and inputs to PUB/MH I-34 Attachment 2 show four areas of concern: Operating and Administrative (O&A) costs, Regulatory Deferral of Overheads, Regulatory Deferral of Depreciation, and DSM spending.
- On O&A costs, Hydro shows significant savings, but only enough to bring the O&A benchmark down to a level that is still above 2011/12 costs plus inflation (a time when the Board was already expressing concern with Hydro's O&A costs being excessive). With an aggressive cost control program, it is entirely possible that O&A costs below those continued in MH16 may be achieved. Hydro should be supported in this endeavour.
- With regard to overheads, MH16 fails to implement the Board's direction and fails to achieve the outcomes needed to protect ratepayers and ensure reasonable rates. The

financial forecast scenarios should be updated to reflect no termination of deferral, and a 30 year amortization of the deferred amounts.

- With respect to depreciation, MH16 similarly fails to implement the Board's direction and exhibits depreciation expense significantly above the levels intended. The impacts of the depreciation procedure imposed by Hydro should be deferred throughout the horizon, and there is no basis to amortize these balances into rates at any time as the intention is that this variance is self-balancing.
- On DSM, the assumptions used by Hydro are based on achieving an energy savings level that fails to meet the targets of the new legislation. This is appropriate, as the legislation specifically indicates the targets cited should be revised to achieve cost-effectiveness (presumably in line with appropriate Integrated Resource Planning (IRP) principles). However, Hydro's DSM proposed spending far exceeds the level that can likely be justified based on IRP principles at this time. It is clear that significant adverse rate impacts arise from Hydro's proposal, despite the purpose of the program being explicitly to "mitigate the impact of rate increases", not to drive rate increases. As a result, the appropriate assumptions for DSM in MH16 should be far reduced from the program presently included, to the benefit of both Hydro's net income and cash levels.
- Based on the above, it is clear that options exist to implement rates today that are within the recent range (3.36% to 3.95%). Given the acceptable performance of scenarios based on 3.95%, and the fact that those scenarios show inputs and assumptions that require significant revision to the benefit of ratepayers, an increase of 3.36% is justified at this time. Continued monitoring will be required in future years but there is no reason to expect rate increases of this level are unsustainable.

1.1.2 Cost of Service and Rate Design

The cost of service study provided by Hydro largely implements the methodology from the recent Cost of Service hearing. Hydro's proposed implementation of one outstanding directive, related to customer service costs, is not reasonable, and requires adjustment (Section 7.1)

Hydro's rate design in respect of industrial customers in large part reflects an appropriate overall structure. However, Hydro has failed to implement the outcomes of the recent Cost of Service review in terms of the amounts each class pays compared to the class costs. For GSL >100kv (12.3% above costs) and GSL 30-100 kV (13.0% above costs) a reasonable basis exists to begin to address this variance (section 7.2). In part this could be addressed by implementing an optional Time of Use program for those customers who can benefit from time-differentiated pricing (Section 7.2.1).

1.2 SUMMARY OF RECOMMENDATIONS

1. Finalize the previous two interim rate increases at the 3.36% level awarded.
2. Reject proposals for increases of 7.9%/year.
3. Implement a rate increase for the 2018/19 year at a level consistent with recent experience, at 3.36% (not on an across-the-board basis).
4. Forecasts related to reducing the Weighted Average Term to Maturity of new debt to the 12 year range should be included in Hydro's IFF projections.
5. Hydro should be encouraged to fully pursue O&A expense reductions, including to plan to achieve levels at or below earlier levels (e.g., 2011/12 or before) plus inflation.
6. Direct a $20 million capitalization of overheads/year indefinitely, amortized over 30 years.
7. Direct the implementation of depreciation rates consistent with the ASL procedure, with no reversion to ELG procedure in the financial forecast, and no amortization of the difference in rates at any time.
8. DSM spending assumptions should be based on significantly reduced DSM spending, on the understanding that future DSM reviews will be based on principled Integrated Resource Planning, and should not be assumed to target 1.5%/year savings or spending levels by rote. This should include direction that the currently deferred $48.8 million in DSM funding from past years not be spent unless justified as part of a DSM plan.
9. Rates for industrial customer classes that are above the Zone of Reasonableness should see a lower than average increase, such as 1-2% below average, consistent with past PUB practice in Order 7/2003.
10. The calculation of Revenue to Cost ratios should be based on measured costs (net of export revenues) to class rates.
11. An optional Time of Use rate design should be reviewed for the large industrial classes, based on customers opting in if they see benefits. To the extent there are lost revenues arising to Hydro from such a program, these amounts are expected to be considerably less than the degree to which industrial customer classes currently pay rates above costs, and therefore can be absorbed within the assigned costs to the industrial classes in the Cost of Service study without requiring increases to other industrial customers.

2.0 OVERVIEW OF THE APPLICATION

Hydro's initial Rate Application requested final approval of the 3.36% interim rate increase granted effective August 1, 2016; a rate increase of 7.9% effective August 1, 2017; and a subsequent 7.9% rate increase effective April 1, 2018 (with further 7.9% annual increases projected through the 2021/22 year, followed by 2%/year thereafter). Hydro sought the increases to be applied across-the-board to all classes, despite Cost of Service analysis showing some classes are paying above the measured costs to serve them, and others are paying rates below measured cost. For the industrial class, Hydro proposed no changes to the design of rates, aside from the across-the-board rate increases.

Following the filing of Hydro's Application, an interim rate increase of 3.36% was granted on August 1, 2017, leading Hydro to revise its request (referred to as 'MH16 Update with Interim'), maintaining the 7.9% increase April 1, 2018 but now forecasting a further 7.9%/year increase projected through the 2023/24 year, a 4.54% increase in the 2024/25 year, and 2%/year increases per year thereafter.

Manitoba Hydro's GRA is based on a 20 year Integrated Financial Forecast ("IFF16") including the electricity operations component (MH16). The GRA includes a number of updated forecasts:

1) **MH16:** Originally the GRA was filed with IFF16 as Appendix 3.1 to the Application, including a 10 year forecast for MH16 (with Appendix 3.3 providing the 20 year forecast), and the full documentation that includes background on analysis and sensitivity testing and other supporting documentation.

2) **MH16 Update:** Provided in July 2017 as Appendix 3.6 (supplement to Tab 3), using the 2017 Load Forecast (slightly lower loads), the 2017/18 Power Smart Plan developed under the now repealed *Energy Savings Act*, the 2017 Energy Price Forecast which is down 17%-20% since the equivalent 2016 forecast (on-peak and off-peak respectively), updated water conditions and export revenues, and economic updates such as inflation and interest rates.

3) **MH16 Update with Interim:** After the PUB's approval of a 3.36% rate increase for August 1, 2017, which deviated from Hydro's forecast rate plan, Hydro refiled some IFF schedules in IFF16 Update with Interim, Appendix 3.8. This filing does not include full supporting documentation but IRs and MFRs were mostly updated to support this new information. This update also included the changes that were made to the forecast in July, 2017 (Appendix 3.6). Additionally, Hydro updated its Uncertainty analysis for MH16 Update with Interim in PUB/MH II-41a-b (both for 7.9%/year rate increases and 3.95%/year).

Until IFF16, Hydro had produced financial forecasts for a number of years based on long-term 3.95%/year annual increases to achieve a debt-to-equity ratio of 75%/25% within 20 years. For IFF16, a separate set of forecasts were made based on this previous rate trajectory of 3.95%/year, as follows:

1) **MH16:** Appendix 3.4 for the original MH16 projections (MH16 with MH15 Rate Increases).
2) **MH16 Update**: No 3.95%/year scenario appears to have been provided.
3) **MH16 Update with Interim:** Updated Appendix 3.4 provided in PUB/MH I-34 Attachment 2.

Hydro's overall rate request can be understood as an amalgam of two basic concepts:

- First, Hydro's application is based on its updated "view" that the 3.95%/year trajectory is insufficient and that a more rapid achievement of debt reduction and equity increases are required. This has led to the doubling of rate increases proposed in the Current GRA for April 1, 2018 and future years at 7.9%/year.
- Second, Hydro has provided extensive information consistent with normal GRAs, which provides comparable information to be able to test the necessity of implementing the previously expected 3.95%/year increase. This information provides a baseline analysis what financial risks ratepayers are exposed to by rejecting Hydro's "view".

The financial differences between the first and second points above are reproduced in the Table below (note MH16 represents the initial filing, before the update and interim rate increase changes).

Figure 2-1: Comparison of Electric Operations Revenues and Expenses Increase / (Decrease) ($millions) [2]

	Increase/(Decrease) (millions of $)					
	2017-2019			2017-2027		
	MH16	MH15	Variance	MH16	MH15	Variance
Domestic Revenues (at MH15 Rate Increases)*	4,615	4,881	(266)	21,115	22,265	(1,150)
Extraprovincial	1,354	1,329	25	6,961	8,402	(1,441)
Other*	88	86	2	358	344	14
Total Revenues	6,056	6,296	(240)	28,435	31,011	(2,577)
Operating and Administrative	1,555	1,680	(125)	5,899	6,693	(795)
Finance Expense	1,850	1,946	(96)	9,903	11,070	(1,167)
Finance Income	(53)	(63)	9	(232)	(233)	1
Depreciation and Amortization	1,251	1,253	(2)	6,536	6,590	(55)
Water Rentals and Assessments	368	341	26	1,361	1,369	(8)
Fuel and Power Purchased	431	513	(82)	1,564	2,292	(728)
Capital and Other Taxes	394	402	(8)	1,741	1,671	69
Other Expenses	284	268	16	1,301	942	358
Corporate Allocation	25	25	(0)	89	90	(1)
Total Expenses	6,105	6,366	(261)	28,161	30,486	(2,325)
Net Income before Net Movement in Reg. Deferral	**(49)**	**(70)**	**21**	**274**	**525**	**(252)**
Net Movement in Regulatory Deferral	243	105	138	684	79	605
Net Income (at MH15 Rate Increases)	**194**	**35**	**159**	**957**	**604**	**353**
Additional Domestic Revenue (over MH15 Rate Increases)	168	-	168	2,530	-	2,530
Financing and Capital Tax Savings	2	-	2	544	-	544
Net Income (at MH16 Rate Increases)	365	35	330	4,032	604	3,428
Net Income Attributable to:						
Manitoba Hydro	**387**	**51**	**336**	**4,011**	**607**	**3,404**
Non-controlling Interest	(22)	(16)	(6)	21	(2)	23
Equity Ratio (MH16 at 7.9% Rate Increases)	**14%**	**13%**		**25%**	**14%**	

*MH15 has been restated to reflect Bipole III Reserve Account amortization in Domestic Revenues rather than Other Revenue.

Hydro's Application also requests the PUB to approve the proposed amortization period for disposition of the regulatory deferral accounts established to capture the difference between Depreciation Expense methods and Operating & Administrative Expense overheads calculated for financial reporting purposes reflecting Board Order and 73/15. Specifically, Hydro has established a regulatory deferral account in its financial forecast to amortize into rates:

[2] Tab 3, Integrated Financial Forecast for original MH16, page 8 of 22

- The difference between Hydro's preferred depreciation procedure (Equal Life Group) and the procedure the PUB directed by used (Average Service Life) until 2022/23, at which point IFF16 forecasts revert to use of the ELG procedure. Hydro is proposing to amortize the difference into rates over 20 years starting in 2019/20.
- The difference between Operating & Administrative overheads calculated under IFRS and what the PUB allowed in Order 73/15 until 2022/23, at which point IFF16 forecasts include this amount in O&A expense. Hydro is proposing to amortize the difference into rates over a 20 year period beginning in 2017/18.

This GRA follows a Cost of Service Methodology review that concluded in 2016 with Board Order 164/16. Hydro's Prospective Cost of Service Study for Year Ending 2018 (PCOSS18) implements the Board approved methodology with a limited number of method changes that have not yet been approved, including the functionalization and allocation for Customer Service General costs (previously categorized as 'C10', now split into three categories – 'C10', 'C13', and 'C23').

The results of PCOSS18 determine each customer class share of the Corporation's revenue requirement and determine if classes are charged fair rates to recover this cost. The Revenue to Cost Coverage ("RCC") ratios resulting from PCOSS18 indicate that certain classes of customers are paying rates that are higher than the measured costs to serve the class, while others face rates that are below the cost standard. Hydro is not proposing any class specific rate adjustments or rate design considerations to address this, proposing only across-the-board rate increases[3].

For rate design issues specific to Industrial Customers, a Time-Of-Use ("TOU") proposal for industrial customers has been under discussion for many years[4]. For this Application Hydro has not included a TOU rate structure as the additional bill impacts that would be borne by certain customers are not advised[5]. Hydro indicates it does not support implementing an 'optional' TOU rate structure for industrial customers who indicate they can benefit from such an offering to help manage their electricity bills and rate impacts[6]. Hydro also indicates it has not had a chance to evaluate TOU rate structure changes resulting from Cost of Service method changes in the 2015 Review[7].

[3] Tab 8, page 33 of 34.
[4] PUB Order 5/12, January 17, 2012, page 220 or most recently Order 26/16, page 16.
[5] Tab 9, page 4 of 18
[6] MIPUG/MH I-5d
[7] MIPUG/MH I-5b

2.1 RATE INCREASE COMPARISON

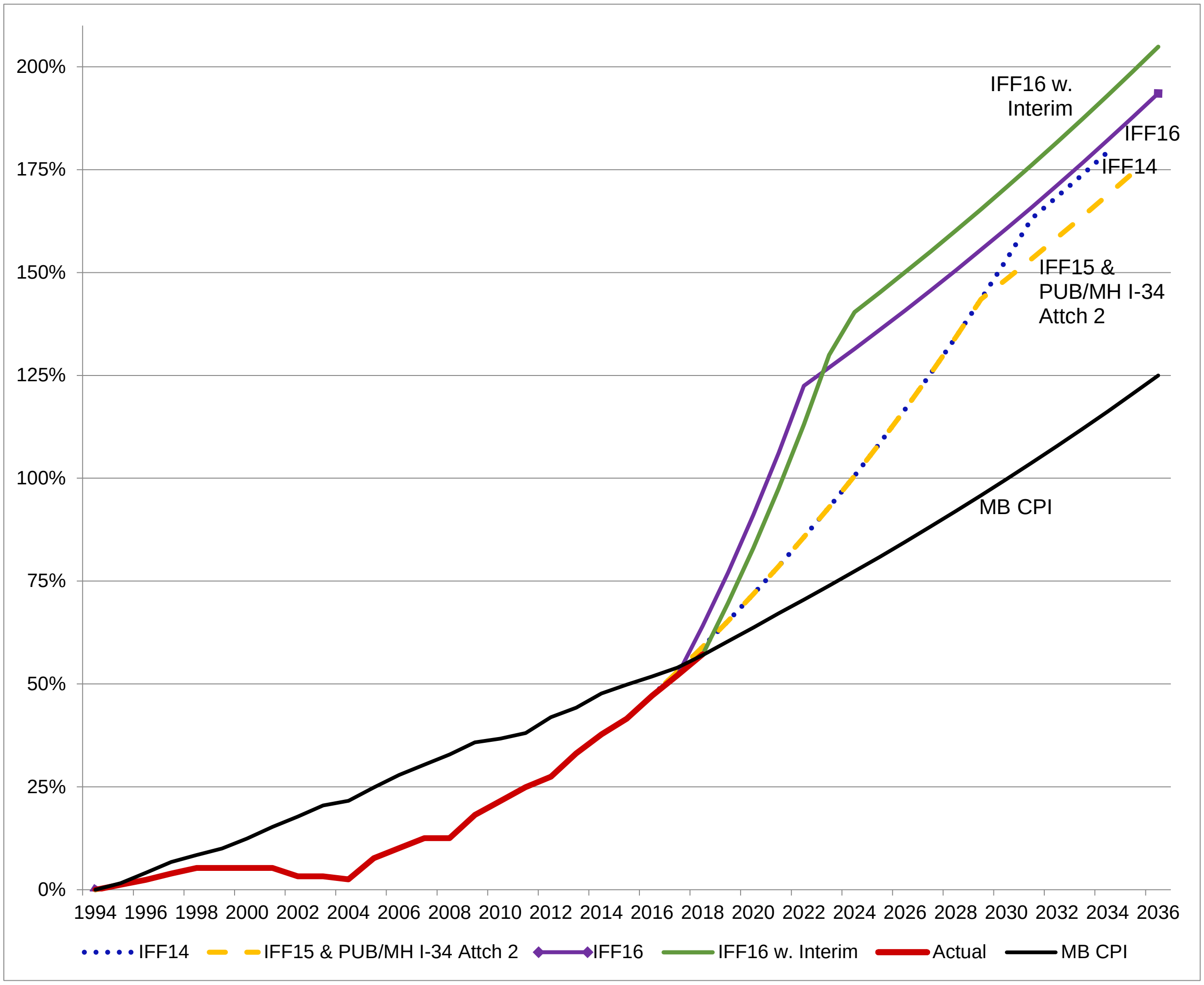
Hydro's current rate proposal results in additional impacts to rates, on top of increases that have occurred in every year since 2007.[8] Cumulatively, including the interim increases in rates, this represents a 43% increase to customers from 2007 to today. Hydro is projecting an additional cumulative rate increase of 53% from 2019 to 2024 in its MH16 Update with Interim. Originally referred to as a "decade of investment", rate increases have now occurred over the last 10 years, and projected rate increases extend higher in magnitude and longer in time than previously proposed.

Cumulative long-term rate impacts are shown in Figure 2-2 on an actual basis from 1994 – 2017 and proposed by Hydro in varying Integrated Financial Forecasts 2018 – 2036. Included is Integrated Financial Forecast 2016 ("IFF16") which has long-term projected rate increases of 7.9% from 2017/18 to 2021/22 followed by 2% per year until 2035/36. Hydro's newest financial forecast, known as 'IFF16 Update with Interim', which includes the 3.36% rate increase August 1, 2017 approved on an interim basis in Order 80/17, also includes projected rate increases of 7.9% for two additional years compared to IFF16 and 4.54% in 2024 before returning to the long-term projected 2% per year. Included for comparison is the actual and forecast Manitoba Cumulative Price Index ("CPI").

Over this extended time period 1994 – 2036, Hydro's rates have increased at a pace that exceeds CPI, and exceed future inflation by a significant margin, as shown in Figure 2-2 below:

[8] PUB-MFR-12

Figure 2-2: Hydro Proposed Cumulative Rate Increase Comparison
Actual 1994 – 2017 & Forecast 2017 - 2036[9]



[9] 1993/94 – 1998/99 Actual rate increases Board Orders 29/91, 62/94, and 51/96, 1999/00 – 2017/18 Actuals and as per PUB-MFR-12, MB CPI from PUB-MFR-53, Attachment 1, page 17; forecast rate increases from corresponding Integrated Financial Forecast: IFF14 - Appendix 3.3 in the 2015/16 GRA, IFF15 – Attachment 1 in 2016/17 Interim Rate Application, IFF16 – Appendix 3.1, IFF16 w. Interim – Appendix 3.8.

3.0 PRINCIPLES OF RATE REGULATION

This testimony has been prepared taking into account regulatory and rate making principles appropriate to Manitoba Hydro as a Crown-owned and hydroelectric generation dominated utility. This section reviews the key principles relied upon in this testimony and supporting rationale.

3.1 BACKGROUND

The premise of rate regulation is that customers generally, or a class of customers specifically, require protection from a monopoly supplier who could, in the absence of competition or a principled decision on the fairness of rates, charge prices that are unreasonable. Principles of Public Utility Rates, by James C. Bonbright (1966)[10] is generally accepted as a relatively comprehensive source for regulatory and ratemaking principles and processes. It describes the primary functions of reasonable public utility rates, with "reasonableness" in this context generally representing a number of different considerations, including:

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

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 bulk power costs in Alberta or Ontario (with government subsidies or rebates at times being provided to certain groups);

[10] Principles of Utility Regulation, Bonbright, J. 1966. Page 49
[11] See, for example, Bonbright, J.C., 1960, "Chapter IV – Cost of Service as the Basic Standard of Reasonableness".
[12] Also see Charles F. Phillips, The Regulation of Public Utilities (3rd. ed,) at pp. 340.

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;[13] or

3) Based on regulated cost-of-service approaches, such as in British Columbia, Yukon, Northwest Territories, Newfoundland and Labrador, or Nova Scotia[14].

Manitoba Hydro fits into this last category, of regulation on the basis of costs to serve the customer.

3.2 REVENUE REQUIREMENT AND THE USED AND USEFUL TEST

Hydro's revenue requirement is reviewed by the PUB and is to include reasonable costs required to run the utility. 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")[15], 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 that 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"[16].

3.3 COST OF SERVICE AND RATE DESIGN

In order to fulfill normal ratemaking principles, the relative levels of rates charged to various customer classes by Manitoba Hydro are to be developed based on principles of "cost of service", or determining a fair allocation of Hydro's costs to the various rate 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 assigned to the relevant class.

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

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

[15] 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.

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

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, economic efficiency, etc.

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

3.4 RESOURCE PLANNING

Within the context of Canadian public utility ratemaking, there is a notable difference in practice between jurisdictions as to whether a utility's capital development plans are reviewed prospectively by the regulator, or only following the implementation of the plan when the related costs are proposed to be included in rates. Some utilities require approvals such as a "Certificate of Public Convenience and Necessity"[17] prior to constructing major assets (e.g., BC Hydro) while for others there is no similar standing requirement for capital spending to be reviewed before construction, such as Manitoba Hydro.

In practice, Manitoba Hydro has been required to have capital resource plans reviewed when major new hydraulic generation is being proposed, such as 1990 in regards to Conawapa, the mid 2000s in regard to Wuskwatim,[18] or the 2013-2014 Needs For and Alternatives To (NFAT) proceeding related to Keeyask and Conawapa.

Underlying these reviews are many public policy elements, among them the premise that the assets will be devoted to public service, and ultimately costs will likely be recovered from ratepayers. As a result, the utility benefits from informed input before it commits to construction regarding the likelihood of being able to recover the costs it incurs, and the regulator (and ratepayers) have the opportunity to review and test the plans and expectations regarding their likely impact on rates or other variables, such as reliability. This is consistent with Bonbright's concept that regulation and ratemaking, and utility service in general, can be heavily tied to customers' "expectations of reasonable continuity of rates on which they must rely in order to make rational advance preparations for the use of services."[19]

[17] BC Utilities Commission Act, section 45(1), available online: http://www.bclaws.ca/civix/document/id/complete/statreg/96473_01
[18] This review was held by a panel of the Clean Environment Commission who had members of the PUB cross-appointed for the review.
[19] Bonbright, J.C., 1960, Page 396-397.

3.5 "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 but instead as a government enterprise. 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 amount for interest cost, for a minimum net cost in the first year of $50-$75 million (if not offset by new revenue, this would mean a 3.5%-5% impact on rates).[20]
- **Low Initial Returns:** Hydro projects would normally be expected have extremely low (or zero, or slightly negative) economic returns in the near-term, but are highly likely to have positive returns over the medium to very long-term. Government entities, relying on a debt guarantee of the citizenry, can find this economic profile attractive. This pattern of economic returns however, is not generally attractive to private sector investors needing to pay annual dividends to investors. Government entities can also be attentive to social benefits (like local and northern investment) or Government revenues from taxation of construction work when the project is first constructed, which would not be relevant to private investors.
- **Annual Risk:** Hydro projects have no assurance of economic returns in any single given year, or even in any multi-year period, 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 have a reasonable expectation of being among the lowest risk power projects available over any longer-term horizon. While a comparable generation asset (in terms of annual GW.h generating capability) of thermal plant would cost a fraction of the cost of hydro plants,

[20] At approximately $15 million per percentage point of rate increase.

and bring a far more stable annual revenue and cost profile year-to-year over the short-term (outside of fuel costs which are typically a flow through to customers and not to the investor), the intense long-term risk to customers 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 to ratepayers.

For a jurisdiction with a good hydro potential, there exists a potentially attractive 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 a more 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, in general, get better with time, one role for regulation is to ensure that today's ratepayers are not being burdened with costs that are appropriately collected from ratepayers later in a hydro plant's life when the economic prospects are vastly improved. Balancing 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[21]. 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[22] 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

[21] 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.

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

requirements at any given point in time[23]. Absent the export markets, the Manitoba power marketplace would likely more closely resemble the non-interconnected jurisdictions in Canada, designed for only a portion of the generation to be hydraulic with a substantial (and more costly) fossil fuel component being part of the supply mix[24]. The access to the export market (for exports and imports as needed) allows larger scale and more economic hydro plants to be developed, and allows rates to be lower than they would otherwise be (were some portion of 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 sales to export markets. As such, Hydro's supply is bolstered, giving the utility increased flexibility to address such situations as unexpected load growth. Also, 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 (whether the early years are in fact cash flow positive or not). In each case, the premise put forward by Hydro 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).

Up until the recent filings, and in particular at the NFAT proceeding, Manitoba Hydro continued to indicate that its intent is to develop new generation such that there are long-term beneficial impacts on Manitoba ratepayers, but at most limited near-term adverse impacts.

3.6 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 simple mathematical benefit to paying down the utility's debt (lower future interest payments), there is no absolute guidance from stock markets, or lenders, or business theory for Hydro to have a specific precisely calculated balance of debt. The assets are paid for by ratepayers as they

[23] 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.

[24] Examples include the island of Newfoundland, the Snare-Yellowknife system in NWT, or the system in place in Yukon.

are being used by ratepayers, and the debt financing of the existing assets can be retired commensurate with depreciation.

The absolute value of "equity" in Hydro as reported on the balance sheet is at best a notional concept, as it is simply the difference between the sum of assets (mostly property, plant and equipment) less liabilities (mostly debt) where the assets are recorded at original cost less depreciation. Consider an example of Grand Rapids Generating Station – it is included in the assets side of the ledger based on original cost from the 1960s ($117 million[25], plus any focused reinvestment since that time) despite a capacity that is a full 70% of Keeyask's[26], and with a role that is far more significant to Hydro's overall system than the lower Nelson plants[27].

Further, lenders do not appear to explicitly require an equity cushion to know they will be repaid, though it can be one factor in support of ratings. Evidence indicates that lenders moreso require a principled and independent 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[28]. 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" to be able to absorb adverse events, such as drought (which, though of far less dollar impact than in past years, remains Hydro's largest single risk[29]). Hydro's chart at Tab 7 (page 26) is reproduced below as Figure 3-1 to illustrate the degree of water flow variability inherent in its system.

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[25] Manitoba Hydro's profile of Grand Rapids Generating Station, https://digitalcollection.gov.mb.ca/awweb/pdfopener?smd=1&did=20775&md=1

[26] 479 MW versus 695 MW

[27] Grand Rapids is a more flexible resource than the lower Nelson plants, due to storage, location, and can play a cornerstone role in terms of frequency control for the entire system and voltage support for the northern regions.

[28] 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.

[29] The Corporate Risk Management Report (PUB MFR-9 (Revised)), at section 2 lists three high consequence risks, drought, plus two others (generic catastrophic infrastructure failure, and a general market access risk related to United States exports and imports) neither of which are items that are appropriately defined in dollar/reserve terms, and each of which are underpinned by substantial actions by Manitoba Hydro to reduce exposure. As a result, neither of the other 2 risks shown under Section 2 Significant and Emerging Risks appear in the Corporation Risk Map (page 21) as a High Likelihood (which is where drought is mapped).

Figure 3-1: Historical Water Supply - System Inflows[30]

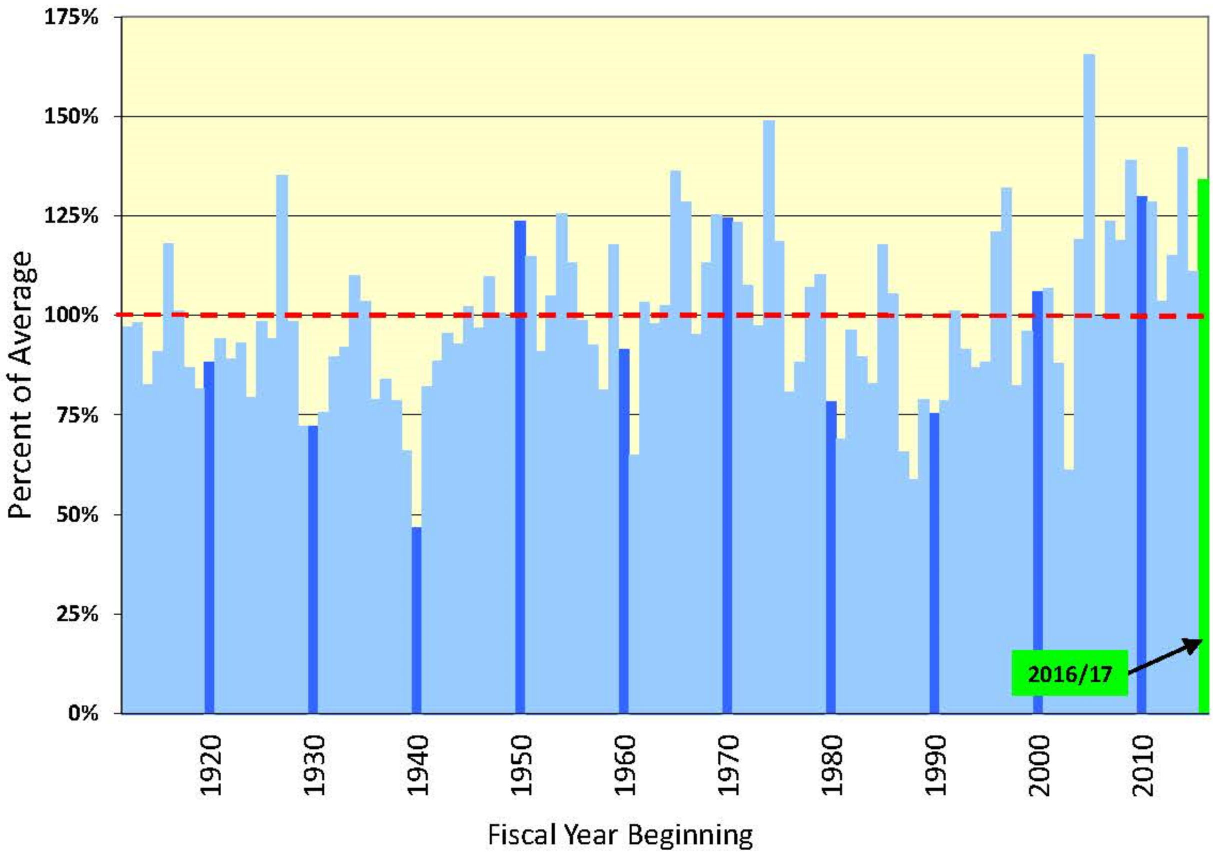

Figure 3-1 shows the extent to which water flows can vary from year to year and drive large swings in financial returns in any given year (or longer), even if the long-term trend is mean-reverting. The financial implications of this water flow variability is shown in Table 3-1 below, based on the underlying financial characteristics of the 2019/20 year.[31]

[30] Figure 7.12. Historical Water Supply from Tab 7: Energy Supply from Hydro's 2017/18 & 2018/19 GRA, page 26.
[31] PUB/MH I-153d

Table 3-1: Financial Implications of Flow Variability, Fiscal Year 2019/20[32]

Flow Year Begin	Annual System Inflow (Kcfs)	MH Hydraulic Energy (TWh/yr)	Net Revenue (M $Cdn)	Variation of Net Revenue from Average (M $Cdn)	Flow Year Begin	Annual System Inflow (Kcfs)	MH Hydraulic Energy (TWh/yr)	Net Revenue (M $Cdn)	Variation of Net Revenue from Average (M $Cdn)
1912	112	32.3	243	83	1963	110	30.2	192	33
1913	119	32.1	235	76	1964	113	30.5	202	43
1914	98	28.0	126	-33	1965	156	37.5	358	198
1915	105	27.8	120	-40	1966	151	36.3	328	168
1916	136	35.2	315	156	1967	114	32.2	237	77
1917	119	33.9	281	121	1968	133	33.4	269	110
1918	105	29.3	163	3	1969	148	37.6	359	199
1919	98	25.6	56	-104	1970	145	36.7	341	181
1920	103	26.4	77	-83	1971	139	35.7	323	163
1921	113	29.8	179	20	1972	125	34.7	288	128
1922	106	28.9	154	-6	1973	115	31.4	219	60
1923	111	29.4	166	7	1974	163	37.0	339	180
1924	99	25.9	63	-97	1975	139	36.2	323	164
1925	120	30.0	186	26	1976	91	25.0	31	-128
1926	111	31.0	211	52	1977	99	23.3	-32	-192
1927	155	37.8	355	195	1978	122	30.8	207	48
1928	114	33.5	269	110	1979	135	34.0	266	106
1929	87	24.1	3	-157	1980	93	24.3	13	-146
1930	89	21.3	-165	-325	1981	85	20.4	-240	-400
1931	87	21.1	-184	-344	1982	115	28.8	152	-8
1932	95	22.9	-52	-211	1983	110	29.5	169	10
1933	101	25.3	46	-113	1984	101	26.3	74	-86
1934	119	30.6	201	41	1985	136	33.1	258	98
1935	118	32.5	245	86	1986	124	34.0	272	112
1936	96	26.2	73	-87	1987	82	21.7	-141	-300
1937	99	25.0	36	-124	1988	72	20.4	-239	-399
1938	89	23.3	-28	-187	1989	91	23.0	-43	-203
1939	79	20.3	-245	-405	1990	85	22.0	-107	-267
1940	55	18.6	-253	-412	1991	91	23.4	-26	-185
1941	92	22.4	-77	-236	1992	114	28.9	152	-7
1942	101	26.4	76	-84	1993	106	29.2	158	-2
1943	108	29.1	158	-2	1994	101	28.0	122	-37
1944	107	29.9	178	18	1995	102	28.4	136	-24
1945	119	31.8	228	68	1996	141	34.7	295	135
1946	113	31.9	232	72	1997	151	36.5	334	174
1947	126	33.5	273	113	1998	106	29.6	158	-2
1948	113	32.3	237	77	1999	110	28.7	146	-14
1949	116	29.7	176	17	2000	126	32.9	255	95
1950	144	35.1	305	145	2001	126	32.5	228	68
1951	132	35.9	331	172	2002	104	26.9	91	-69
1952	107	31.4	220	60	2003	72	19.9	-272	-432
1953	124	32.8	255	95	2004	140	32.9	261	101
1954	143	37.0	354	194	2005	175	38.7	385	225
1955	133	35.7	310	150	2006	113	31.9	210	50
1956	119	32.7	252	93	2007	150	36.0	331	171
1957	111	30.8	202	43	2008	141	36.5	337	177
1958	96	25.4	49	-110	2009	151	36.0	321	161
1959	137	33.3	266	106	2010	162	38.5	377	218
1960	102	29.1	152	-7	2011	153	35.9	308	149
1961	75	20.6	-232	-391	2012	121	33.2	262	102
1962	119	29.2	159	0	2013	134	35.8	315	156
					Average	115	30.05	160	0

Table 3-1 above is based on a concept of "Net Revenue" which is a subset of the items that make up net income. The full net income in the year shown (2019/20, under Appendix 3.8 assumptions) is $205 million.[33] For an assessment of the impact of a given water condition on the 2019/20 year, it is necessary to add this $205 million to the values shown in the column entitled "Variation of Net Revenue from Average" – for example, for the worst single water year in Hydro's hydrologic record look to 2003, which shows negative $432 million in net revenue worse than the average condition. Adding $205 million to this value makes this flow year equal to a $205 million net loss. Comparing to the actual financial outcome of the 2003/04 year (net loss of $436 million) shows the significantly reduced exposure to drought in the current forecast compared to earlier periods.

32 PUB/MH I-153d
33 Appendix 3.8

4.0 PROPOSAL TO DOUBLE THE PREVIOUSLY PROJECTED INCREASES, FROM 3.95% / YEAR TO 7.9% / YEAR

Hydro first provided the concept of the need for long-term increases of 3.95%/year as part of the NFAT filing.[34] However, rate increases in this range to support the major capital development plan have been included since at least IFF09[35] covering a period then known as the "decade of investment"[36] (at that time at 3.5%/year). In the NFAT Review, the 3.95%/year rate increase scenario was tied to the Preferred Development Plan ('PDP', the large future development scenario that included both Keeyask and Conawapa). The value was derived as the amount needed for rate increases from 2014/15 to 2031/32 to achieve a 75% debt ratio by 2031/32 based on the original NFAT inputs.[37] Other smaller development plans (such as plan 5/6, as was ultimately recommended) required somewhat lower rate increases.

It is important to note that the NFAT rate projections were not intended to be implemented as designed. Hydro emphasized this by providing two alternative rate design methodologies in the NFAT.[38] In response to concerns about the PDP having the highest annual rate impact of any of the main plans under the initial rate projection method,[39] these alternative methods indicated a willingness to consider alternatives such that the preferred plan was not the highest rate impact of all plans. However, each of these alternative rate design methodologies were premised on achieving targets such as a 75:25 debt ratio later than 2031/32.[40] These discussions of alternative rate designs led to the PUB to recommend a relaxation of the need to achieve 75:25 by 2031/32, noting that:[41]

> "Manitoba Hydro's financial targets determine how rates are set. Targets include a self-imposed 75/25 debt-to-equity ratio. Manitoba Hydro's financial forecasts are premised on rates being increased sufficiently to allow the debt-to-equity ratio to recover to the target level over a 20-year time period, followed by lesser rate increases thereafter. During the NFAT Review, Manitoba Hydro also provided alternate suggested rate methodologies that

[34] NFAT Appendix 11.4, Volume 2 of 2, page 163 of 648
[35] Appendix 5.2 from Hydro's 2010/11 and 2011/12 GRA, which included 3.5% rate increases annually starting with the major new project development period of 2012/13.
[36] Hydro 2010/11 and 2011/12 GRA, Tab 2, page 3. November 30, 2009.
[37] NFAT Business Case, Executive Summary, Table 4.
[38] For Example, NFAT Exhibit MH-104-12-2
[39] NFAT Chapter 13, page 24 and Chapter 14 page 19
[40] The case for the PDP in MH-104-12-2 was supported by Hydro by indicating that an alternative rate design methodology should be assessed which yielded only 84:16 debt:equity by 2031/32, and 86:14 if higher levels of DSM were targeted.
[41] NFAT report Page 29 of 306

would increase rates more gradually, with the result of pushing back the date at which financial targets will fully recover.

A doubling of rates will have a significant effect on all ratepayers. This includes not just residential customers, but also commercial and industrial ratepayers, the latter of which are sensitive to price increases as it can affect their competitive position. The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased."

This PUB recommendation was accepted by the Government of Manitoba as shown in the Minister's letter to Hydro setting out the Manitoba Government's response to the NFAT report,[42] as follows:

"Also consistent with the PUB's advice, we request that the Manitoba Hydro-Electric Board review its current 75/25 debt-to-equity target with the aim of moderating rates for consumers while ensuring strong financial health for the corporation including maintaining sufficient retained earnings. We further urge the corporation to maintain tight cost controls overall to support string financial performance and low rates for all Manitoba Hydro customers."

It is not clear that Hydro has ever undertaken the cited review "with the aim of moderating rates for consumers" compared to a 75/25 debt:equity target.[43]

The 3.95%/year rate increase trajectory has been maintained as a baseline since the NFAT through IFF12, IFF13, IFF14, and IFF15, with slight revisions as to the projected end date of the 3.95%/year annual increase series, and the date for achievement of various debt/equity levels. Further, 3.95%/year increases have now been sought by Hydro on a number of occasions, with granted approvals ranging from 2.75%/year to 3.95%/year.[44]

The current filing contains proposals that show a marked departure from the earlier scenarios. There are effectively three basic rationales provided by Hydro for the plan to double the previously projected 3.95%/year increases:

[42] Produced as part of Exhibit MH#45 in the 2015/16 GRA
[43] MIPUG/MH I-2q notes that the Minister's letter was relayed to KPMG, but there is no discussion of objectives of moderating rates for consumers among the criteria considered by KPMG.
[44] May 1, 2014, August 1, 2015, August 1, 2016

1) **Self-Supporting:** Tab 2 of the GRA filing, which notes: "In Manitoba Hydro's view, a financial plan that returns the Corporation to a 25% equity level over almost 20 years is not credible as a commitment to being a self-supporting entity."[45]

2) **Customer Interest:** The perspective provided in MIPUG/MH II-4b (in response to a question about comparability in financial metrics to other provincially owned utilities), which notes: "Regardless of what other utilities and their regulators are doing with AOCI in their ratio calculations, it is in Manitoba Hydro's customers' best interests to contribute to the corporation's revenue requirement now rather than 10 years from now in order to permanently reduce debt and future interest costs which will result in lower cumulative rate increases in the long-term than what would have otherwise been required with lower early rate increases and higher debt levels."

3) **Protect Provincial Government:** Hydro notes that without the proposed rate increases, the Corporation views itself as "an untenable risk" to "the overall economic health of the Province of Manitoba".[46] The interim rate increase submission from the Coalition also captured Hydro's claims on this matter, citing that on February 7, 2017 the Chair of Manitoba Hydro stated "We want to make people understand, this is a big problem. It's not a small problem. We take that position not only from Manitoba Hydro's perspective, but from the perspective of the government of Manitoba and the people of Manitoba; Hydro is a ticking time bomb."[47]

This submission addresses each of the above items in turn.

4.1 HYDRO'S SELF-SUPPORTING STATUS

The issue of Hydro as a self-supporting entity that fully recovers its costs has been a core concept for rate setting going back before the late 1980s. Hydro accurately summarizes this concept in noting: "It is generally accepted that Manitoba Hydro's domestic ratepayers ultimately bear the cost of operating, maintaining and renewing the system."[48] This is consistent with evidence going back, for example, to the Board's hearing on the 1996/97 GRA,[49] which similarly reviewed Hydro's concern about "…the risk that Hydro could become a financial burden to the taxpayers of Province…"[50] and desires to increase financial strength to deal with this risk.

[45] Tab 2, page 28
[46] Tab 2 page 2
[47] http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-sandy-riley-rate-increases-1.3970470
[48] Tab 2 page 26
[49] Order 51/96
[50] Order 51/96 page 14

A key question at this time relates to 'what is meant by being self-supporting?' At least three concepts have been conflated:

1) **Hydro's comments in MIPUG/MH II-17d:** "Manitoba Hydro's near term objective is to be able to meet all of its financial obligations including debt service and capital reinvestment out of the revenues of the Corporation. This is the definition of "self-supporting" that the Corporation endorses." [51]

2) **The KPMG view in Appendix 4.1**, which notes that "A reasonable hypothesis is that Manitoba Hydro would be considered unable to meet its financial commitments, and therefore no longer self-supporting, once its debt has grown to the point at which it cannot reasonably be recovered from Manitoba Hydro electricity ratepayers going forward. Under this scenario, some portion of the debt would need to be assumed by the Province."[52] KPMG then notes:[53]

   > "Manitoba Hydro would be deemed to be no longer self-supporting once it reaches a position of near zero retained earnings <u>and</u> rates have increased in real terms such that Manitoba can no longer be considered a cost-competitive jurisdiction with respect to electricity rates." (emphasis in original)

3) **The credit ratings agency reports**, as referenced in Tab 4, which note that DBRS and Moody's continue to treat Manitoba Hydro debt as being self-supporting, but that S&P no longer considers Manitoba Hydro to be self-supporting. Further detail provided in Information Requests highlights that the S&P change to Manitoba Hydro's status occurred at the same time that at least three other Canadian Crown utilities (SaskPower, NB Power and Nalcor Energy) were similarly reclassified as non-self-supporting, and was driven by a change to S&P's basic methodology. The fact that the driver of the change was methodology rather than outlook would appear to be consistent with earlier information provided by Hydro in extensive NFAT cross-examination (reproduced in Attachment B to this submission) that the credit ratings agencies were intimately aware of Hydro's capital plans (including, at that time, the plan to finance Conawapa), that they follow all ongoing regulatory proceedings well and with sophistication, that they had reviewed the fact that Hydro planned 20 years to re-attain a 75:25 debt ratio, and that the rating agencies as well as the actual lenders viewed the capital plans (including the financing plans) very favorably particularly given

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[51] MIPUG/MH II-17d. Hydro goes on to note: "Manitoba Hydro's 10 year objective is to meet its target of 25% equity such that Manitoba Hydro's overall debt is kept at levels that promote both rate stability and long-run lower rates for its customers as compared to plans which defer addressing the Corporation's current financial condition" but does not tie this latter objective to the definition of self-supporting.
[52] Appendix 4.1, page 6
[53] Appendix 4.1 page 7

the investment in assets that improved the system capabilities. Absent a methodology change, this supportive view would not be consistent with an S&P finding that Hydro is not self-supporting.

The core issue of concern for this proceeding is whether Hydro is indeed not self-supporting without a series of 7.9%/year increases, and whether there is some reason for the PUB and ratepayers to accept a revised concept of self-supporting than has been in place for many years.

On this question, by almost any measure noted (other than the new S&P criteria), Hydro is self-supporting over the next 10 years and this conclusion is not dependent on changing 3.95%/year increases to 7.9%/year. This is shown by the following data derived from PUB/MH II-34 Attachment 2 (MH16 Update with Interim scenario and 3.95%/year rate increases) and other IFF 16 inputs:

- With respect to Hydro's goal to meet all "financial obligations including debt service and capital reinvestment out of the revenues of the Corporation":
  - Hydro exceeds a Capital Coverage ratio of 1.0 in all future years, and also meets or exceeds the target of 1.2 in all years.[54] This measure indicates the revenues of the Corporation fulfill all financial obligations including interest cost and capital reinvestment for normal capital spending (i.e., excluding major new generation and transmission) consistent with Hydro's long-term target in each year. In short, annual cash inflows finance all current year cash expenses, all interest payments, government charges, fuel and purchased power, etc., as well as cash financing all construction occurring on the "normal" components of the asset base. To the extent the measure exceeds 1.0, surplus cash is available to contribute towards the Major New Generation and Transmission category or retire debt. As this ratio stays between 1.2 and 1.7 during the first 10 years of the IFF, Hydro has between 20% and 70% more cash generated in these years than is needed to meet the basic self-sufficiency criteria, and also indicates that absent Major New Generation and Transmission construction, Hydro would be rapidly retiring debt. In fact debt repayment occurs with 3.95%/year rate increases, as expenditures in the Major New Generation and Transmission category are very small following 2022/23.[55]
  - If the Major New Generation and Transmission category was included in cash flows, consistent with Hydro's measure of CFO:Capex at PUB/MH I-23b, Hydro obviously fails to generate sufficient cash to make all capital payments for Keeyask etc. out of cash flows

[54] PUB/MH II-34 Attachment 2.
[55] IFF16 (Appendix 3.1 to the GRA) page 51. Following 2021/22, the only projects are very small spending on what appear to be final outstanding Keeyask completion tasks, and the Gillam Redevelopment and Expansion Program (GREP) which Hydro notes in PUB/MH II-43a-c is being materially scaled back and is unlikely to have any spending in the Major New category in future IFFs.

(which would be an unreasonable standard[56]). A key finding, however, is that Hydro begins to be able to cash flow finance <u>all</u> capital assets (including Major New Generation and Transmission) starting 2023/24 with 3.95%/year rate increases – which is only one year following what is achieved with 7.9%/year rate increases (2022/23)[57].

- With respect to KPMG's test, there is no prospect under any of the scenarios analyzed with 3.95%/year rate increases of dropping below 5% equity by 2024[58], and only very long-term scenarios show even a 5th percentile chance of equity reaching zero (starting 2031 – a full 13 years out). But these outcomes only occur if a 3.95%/year rate increase regime is stubbornly adhered to through 2028/29 (11 years) and 2%/year thereafter despite significantly deteriorating conditions. Assuming 2% inflation occurs over the period, this would mean an approximately 22% real price increase to the cost of power over the next 11 years[59], which is unlikely to lead to the harsh outcome that "Manitoba can no longer be considered a cost-competitive jurisdiction with respect to electricity rates" as required by the KPMG test. In short, with 3.95%/year increases, there appears to be no prospect that KPMG's test for self-supporting (zero retained earnings combined with uncompetitive rates) would fail over the near term or the long-term as currently projected.
- With respect to the credit rating agencies, Hydro has already clarified that there is no internal objective to meet the new test for self-supporting status under the S&P criteria. This is reasonable, as relevant comparators such as SaskPower also fail to be considered self-supporting, despite maintaining a 60-75% debt ratio target (as a thermal utility, SaskPower's use of equity and debt financing is lower than Manitoba Hydro, but instead they incur substantial fuel costs each year, so the debt percentage of this system is kept at a lower level). For the remaining credit rating agencies, as discussed in Appendix B to this submission, Hydro's evidence since NFAT has been that the agencies remain supportive of the capital plans so long as an accommodative and responsive rate setting regime is in place to deal with adverse conditions in the event they unfold. For example, DBRS specifically notes that "DBRS could consider reclassifying a portion of the Utility's debt to be tax-supported should the financial health of the Utility deteriorate to the point where its expenses cannot be recovered through rates."[60] As noted above, the 3.95%/year rate increase scenario shows all current-year utility expenses are readily recovered through rates, plus

[56] Meeting such a standard would imply that a utility has rates high enough to fully cash flow major new assets that will last for 100 years of more out of current rates, which would be a clear indication that current rates are too high and not meeting the basic target of funding only assets that are 'used and useful'.
[57] PUB/MH II-23a-b notes that at 7.9% increases, Hydro's cash flow exceeds capital expenditures starting in 2022/23 at page 3, while 3.95% increases give this same result in 2023/24 at page 6.
[58] Appendix 4.5, Figure 6-15, page 75
[59] 1.95% above inflation for 11 years
[60] GRA filing, Appendix 4.4, page 2

> a measure of capital expenditures, and further that debt retirement is projected starting 2023/24. In short, the DBRS comments indicate there is only future risk relative to a portion of Hydro's debt not be self-supporting if adverse conditions arise, necessitating a responsive rate regime.

In short, outside of the unexpected and unavoidable result arising from S&P's change to their definitions, all indications are that there is no need to move to a 7.9%/year annual rate increase regime to achieve a utility that is self-supporting.

If anything, a key conclusion from the above material is the lack of need for a 7.9%/year rate increase today, but instead a significant requirement to communicate regulatory support and a reliable regulatory regime to lenders and credit rating agencies. This is specifically cited in the desirable characteristics that play into the ratings criteria from S&P provided in MIPUG/MH I-8a-k, as follows:[61]

> Regulatory stability:
>
> - Transparency of the key components of the rate setting and how these are assessed
> - Predictability that lowers uncertainty for the utility and its stakeholders
> - Consistency in the regulatory framework over time
>
> …
>
> Regulatory independence and insulation:
>
> - Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
> - Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event"

These requirements of transparency, predictability or, more importantly, consistency in the regulatory framework are not consistent with rapid rate policy changes as proposed, particularly where such rapid policy changes are driven by the changing "view" of each new set of Management and Boards of Directors of Hydro that are appointed from time-to-time (an item Hydro cites as a key reason for the change in direction in the submission on interim rates).[62]

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[61] MIPUG/MH I-8a-k, citing Ratings Direct, Criteria| Corporates| Utilities: Key Credit Factors For the Regulated Utilities Industry copyright 2016, page 5.

[62] Manitoba Hydro June 2, 2017 letter to the PUB regarding Interim Rates, Exhibit MH-8, page 11, which notes "A new Board of Manitoba Hydro has been appointed along with a new President and CEO and a new Chief Finance & Strategy Officer" as a rationale for what has changed in between IFF15 and IFF16 necessitating the new higher rate regime.

Potentially the more useful consideration in support of self-sufficiency is in communicating to the marketplace that a rate regime based on a concept of stable increases (such as 3.36%/year or 3.95%/year) can be consistent with a long-term successful financial performance, even if conditions such as water flows or interest rates change for the worse. This may involve somewhat more refined communication regarding the identification and quantification of possible rate response mechanisms that would be adopted if necessary, as is further discussed in Background Paper C regarding the Uncertainty Analysis.[63]

4.2 RATE INCREASES IN THE CUSTOMERS INTERESTS

The assertion that Hydro's 7.9%/year rate increase request is in the customers' interest[64] appears to hinge on 2 basic premises: 1) that customers are at risk of rate shocks if debt is not paid down quickly enough, and 2) that over the long-term, an investment by customers today will lead to lower rates in the future. PUB/MH II-21a-b reviews the purported benefits of a 7.9%/year rate increase scenario:

> In doing so, Manitoba Hydro's customers enjoy both a substantially diminished risk of rate volatility and a significantly higher probability of lower rates beyond 2026/27 as compared to plans to address the Corporation's condition over 15 or 20 years[65].

These two assertions portray the role of rate increases in building financial reserves in Hydro (rate stability, and lower long-term rates). Consider the submissions of Hydro's Chief Finance Officer Mr. Rainkie at the NFAT proceeding:[66]

> Of course, customers have to pick up the total cost of the Company over time. I mean, it's just the fundamental, you know, principal of Manitoba Hydro. There's no shareholder here that's earning a 10 percent return. We work on behalf of the ratepayer, and we have to get a decent recovery of our costs over time to maintain, you know, a financially viable company for customers. In the end, the retained earnings that we have are for customers. They're not for a shareholder. They're not for bonuses.

Similarly, the *Manitoba Hydro Act* sets out in section 39(1) a general framework that prices for power should include operating costs (s.39(1)(a)), debt related costs (s.39(1)(b)) and reserves (s.39(1)(c)) and further in s.40(1) states that reserves should permit amortization of capital costs, self-insurance, and rate

[63] Supplementary Background Paper C: Uncertainty Analysis, prepared by P. Bowman on behalf of MIPUG, October 2017

[64] Hydro does not appear to provide any customer surveys indicating customers are in support of this purported customer interest.

[65] PUB/MH II-21a-b

[66] NFAT Transcript page 2807, lines 4-14

stabilization for extraordinary contingencies. There is no reference to profits, equity, return on equity, or shareholder dividends.[67]

At its core, the above references reflect that broad customer interests (including the typical interests of industrial customers) are for stable and predictable rates, maintained at the lowest level consistent with reliable service. The key question is, in what way does a 3.95%/year rate increase regime fail to meet these interests?

It is clear that rate projections are lower under the IFF scenario with the 3.95%/year increases throughout the entire IFF horizon than under MH16, particularly the early years where forecasts are most reliable. Mathematically, it is clear that Hydro can generate scenarios that show large increases through the next 10 years, followed by major rate decreases in year 11 (such as PUB/MH II-28a-b, which has 24% rate decreases in the 3 years following 2026/27) and suggest that this end result is in customer interests due to lower bills in the years following 2026/27. However that result is only in customer interests in the same manner that paying off a home mortgage in 10 years is in a customer's interests in that, looking to year 11, the rote mathematics indicate their costs would be lower– i.e., only if all relevant considerations of affordability, the time value of money, and alternative uses of funds are ignored.

Further, the result also ignores the relative value and cost of capital to the parties (Hydro versus ratepayers). The NFAT review considered the question of what trade-offs a customer should desire in terms of higher rates now to yield lower rates in future, including in the assessment of the appropriate customer discount rate[68]. In such discussion, it is important to recognize the unique circumstances of some ratepayer groups, whose alternative uses of funds come at a much higher cost than Hydro's rate to borrow. This could include industries who have investment opportunities at a higher Internal Rate of Return than Hydro's borrowing costs, or low income customers who have much higher priorities for use of funds (such as repaying high cost debt, or simply funding living expenses). For these groups, paying added amounts in power bills now to avoid future costs more than a decade away, and where these avoided costs are linked with interest on government guaranteed debt (a low cost source of financing), is not a beneficial trade-off. This effect is exacerbated by the mismatch between today's ratepayers rapidly paying down debt associated with an asset like Keeyask which remains in a cash negative state (under current projections) until the mid-2030s[69], but will provide 100 years or more of future economic value to ratepayers receiving service from this facility.

[67] There is reference in the Act, section 43(5) to a distribution from net income that is only applicable to the years ending March 31, 2002, 2003 and 2004.
[68] NFAT Final report, such as page 157, 178.
[69] Tab 2 page 25

In respect of rate stability, the PUB/MH I-34 Attachment 2 scenario shows relatively little likelihood of requiring a future rate shock (e.g., having to impose rate increases in future as high as 7.9%/year on a sustained basis) to ensure Hydro is maintained as a self-supporting utility, as reviewed above. In support, consider that Hydro's risk register shows that the worst single risk (a 5 year repeat of the worst drought on record) requires only a 1.29%/year incremental rate increase per year over 2019/20 to 2027/28 to fully address the adverse impact[70]. In short, even with the worst 5 year drought, rate increases in the mid-5%s[71] would be expected to yield the same financial outcome as the 3.95%/year scenarios (retained earnings of almost $3 billion at 2026/27[72]), a rate impact that is well below the 7.9%/year now proposed.

In regard to long-term customer interest in reaching 25% equity, it is of note that Hydro's Board reviewed materials with BCG that in no way provided for customer rate benefits (such as targeting rate decreases) after reaching a 25% equity position. The materials provide that after 25% equity has been achieved, this would create "'surplus' equity positions which can be used to maintain investment grade rating, issue government dividend and/or fund future capital projects."[73] There is no mention in this document of rate decreases. This type of outcome is not consistent with the basic premise of Manitoba Hydro akin to a non-share capital entity that is structured where "the retained earnings are for customers"[74], tied to reserves set aside for rate stability per the *Manitoba Hydro Act*.

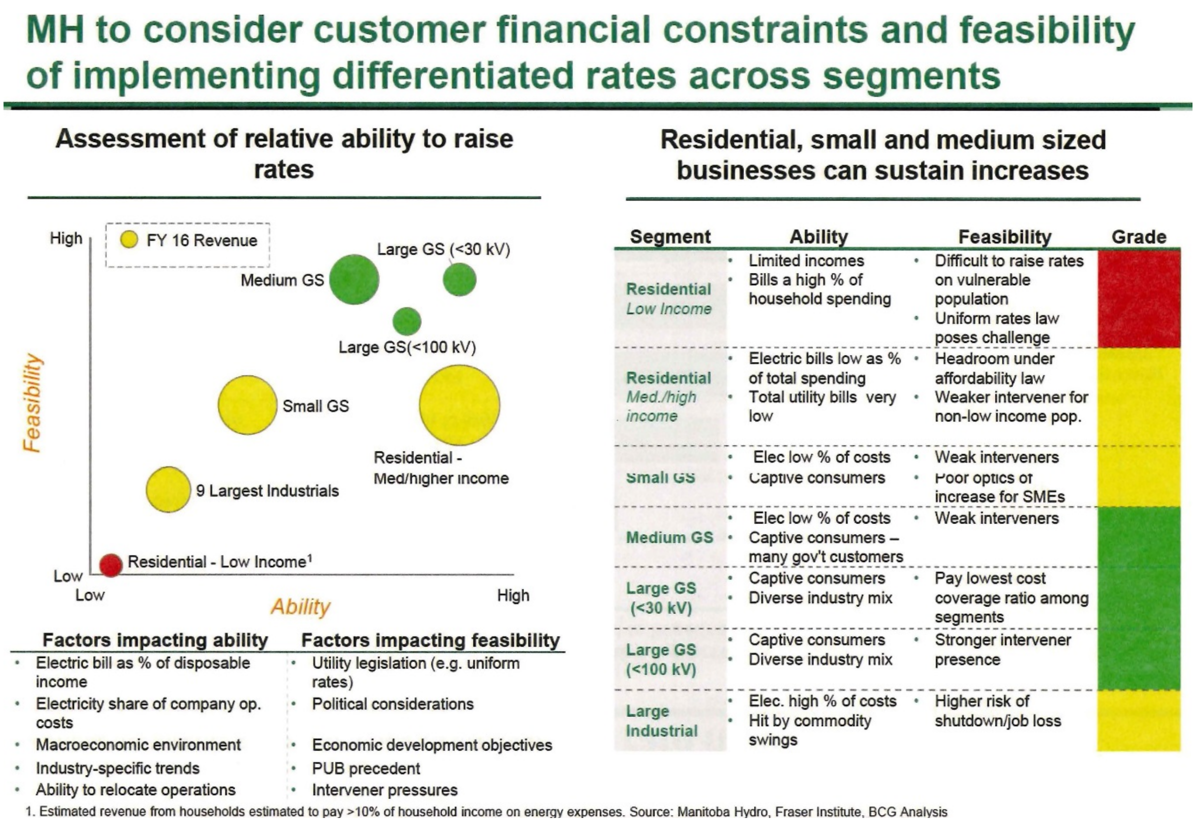
The outcome is also not consistent with regulatory principles that assets should be brought into rates once they are used and useful rather than pre-funded from surplus rates or equity. Finally, the outcome is not consistent with any concept of having set aside customer funded reserves, if these customers' future rates and surplus reserves are then used to fund dividends to government, as such outflows would only come at the expense of the reserves being available for the intended purpose of stabilizing future customer rates. Such a dividend could only ultimately come at the expense of future customer rate levels.

Finally, it must be noted that the above scenarios also assume any beneficial customer interest in the 7.9%/year rate increase scenario arises only in the event Hydro's revenues increase by a commensurate amount. The Hydro filing provides no apparent estimate of the economic impact on Manitoba of raising rates, outside of the limited concept of incremental elasticity (how much less power might be used on an incremental basis due to higher rate increases, due to a customer's price response). Additionally, this estimate largely ignores stepped changes such as risks of plant closures and downstream effects if the increases lead to job losses, outmigration or reduced household budgets. BCG highlighted this issue in their

[70] PUB/MH I-45
[71] 3.95% plus a drought-related component on the order of 1.29%
[72] Per PUB/MH I-34 Attachment 2, retained earnings total $2.879 billion at 2026/27.
[73] PUB MFR-72 pdf page 406 of 615
[74] NFAT Transcript page 2807, lines 4-14

presentation of August 25, 2016, which specifically notes that increases drive a "higher risk of shutdown/job losses" for large industrials as shown in Figure 4-1.[75]

Figure 4-1: Customer Financial Constraints and Feasibility of Implementing Differentiated Rates Across Segments[76]



Along with potential industrial impacts related to risks of shutdown/job loss, no information is provided by Hydro regarding the basic broader economy impacts of the higher revenues being charged by Hydro solely for the purpose of Hydro's own debt reduction. Consider that the extra amounts paid by domestic ratepayers to Hydro over the 2018/19 to 2027/28 period (10 years) under the 7.9%/year trajectory versus 3.95%/year scenario[77] is $3.616 billion, or an average of $362 million per year. This is simply the incremental rates charged over and above the 3.95%/year scenario on average during this decade (and does not include GST, PST and where relevant City Tax which would increase this value by a significant amounts). For perspective, total amounts collected in the province in 2017/18 for Manitoba Corporations Tax is $334 million, Payroll Tax is $477 million, and 1% on the Provincial Sales Tax is $294 million[78]. The net impact from Hydro's rate changes on the economy could be more significant than these examples, as

[75] PUB MFR 72 Attachment, pdf page 468 of 615.
[76] PUB-MFR-72 Attachment, BCG Presentation from August 25, 2016, pdf page 468 of 615.
[77] Comparing Appendix 3.8 to PUB/MH I 34 Attachment 2.
[78] From Details - Estimates of Revenue, per page 143 of the 2017 Manitoba Restated Estimate of Expenditure and Revenue http://www.gov.mb.ca/finance/budget17/papers/r_and_e.pdf

government revenues are in part used to fund activity within the Manitoba economy with associated multiplier benefits – the Hydro increases are solely slated to pay down debt, which does not generate production in the economy.

In short, Hydro's assertion that 10 years of heavy rate impacts being in customer interests does not bear out under scrutiny given the evidence available. It is not clear that customers would ever experience any benefit from added contributions towards debt repayment now, even though it would reduce Hydro's costs. Lower rates are purely hypothetical, may occur some point well into the future, may be too small in scale to provide a net benefit (given Hydro's cost of borrowing is relatively low compared to the cost of these funds for many customers), or may end up elsewhere entirely (i.e. divested to the shareholder or to unspecified new capital costs). Contrarily, increasing rates for debt repayments will have adverse impacts on the Manitoba economy.

4.3 DEBT REPAYMENT TO PROTECT PROVINCIAL GOVERNMENT

The final rationale that Hydro cites for benefits from the 7.9%/year scenario is that the higher rates, combined with use of these funds to achieve debt reduction, will play a role in protecting the Provincial Government from adverse impacts of Hydro's debt load.[79] The argument, however, is extended such that Hydro's debt reduction will additionally benefit the Province in protection from adverse impacts arising from the provinces own debt load.[80]

For the purposes of assessment focused on matters related to rates, the cited concerns appear poorly supported or highly speculative. For example:

- **Cost Implications:** Hydro has cited that debt borrowed by Hydro could adversely affect the Province's cost of credit, but no evidence has been provided of whether such costs to the Province are in fact occurring, and if so, to what magnitude. Note that, at the NFAT hearing, the Board's Independent Expert on capital markets, Pelino Colaiacovo of Morrison Park Advisors, testified: "So, you know, if, for whatever reason, a fraction of Manitoba Hydro's debt were to be considered stranded by credit rating agencies or capital market analysts, it would be a portion of the debt, never the whole amount."[81] No assessment has been provided on what proportion of Hydro's debt, if any, could be considered to be stranded by the lending markets. Also, Hydro has provided in

[79] For example, Tab 2 page 2
[80] For example, Tab 2, page 38 notes concerns regarding the overall combined debt to GDP of Manitoba and Manitoba Hydro, noting: "Since the Corporation's last GRA, the fiscal year-end debt of the Province of Manitoba has increased by 33.8%, from $17.3 billion (March 31, 2014) to $23.1 billion (March 31, 2017 estimated) pushing debt to GDP to 34.4%" This debt to GDP is the figure relating solely to the provincial government's own debt and not to Manitoba Hydro's.
[81] NFAT Transcript, page 7514

PUB/MH I-41a-b a summary of the Provincial borrowing spreads as compared to Ontario, showing that spreads with Ontario (the premium Manitoba pays to borrow compared to what Ontario pays) peaked in mid-2016 and have since narrowed despite two S&P downgrades occurring over this period. Adverse movements in the spread were seen earlier (from mid-2014 to mid-2016)[82] but this was a period where only Moody's was downgrading the Province, and Moody's does not consider Manitoba Hydro debt in their ratings so these downgrades were not driven by Manitoba Hydro's debt. In short, there is no sign that any updated information on Manitoba Hydro's debt is leading to a higher cost of credit for the province.

- **Guarantee Fees:** In the event the Province did bear costs owing to Hydro's debt level, there is no assessment provided as to whether any impacts on the Province as a result of the Hydro borrowings would exceed the compensation the Province receives from ratepayers in exchange for the provision of the guarantee. With the major planned borrowing by Hydro, this payment will peak at over $230 million per year in the near future[83]. Further, Hydro has been paying guarantee fees that increased a number of times over the years, ultimately reaching 0.95% by 2002 and 1% by 2007[84]. From 2002 to 2014 Hydro's net debt grew from $5 billion to over $10 billion and more so since 2014, meaning that since 2002 (a period of 15 years) payments have ranged from $50 million to well over $100 million per year (totaling $1.33 billion from 2002 to 2017).[85] During this time there is no indication that Hydro adversely affected the province's cost of credit. Considering that the debt guarantee form is a kind of backstop or insurance, no evidence has been provided that the Province is being exposed to risks or costs that exceed the payments it has received (viewed as a form of insurance premium) over the period.

- **Economic Impact:** As reviewed above, Hydro has at best considered very limited information regarding the potential adverse economic impacts on Manitoba of significant rate increases, with a net impact totaling over $4 billion over 10 years.[86] The spin off impacts of such changes will result in adverse impacts on the level of economic activity in the province, and consequent downstream effects on the Provincial Government finances. It is not clear that any such adverse impacts to Provincial Government revenues are outweighed by a notional concept of benefits to the Province from Hydro rapidly reducing the debt related to the major new capital projects. Finally, in the event there are adverse economic implications from Hydro's rate increases that dampen Provincial

[82] The Manitoba Ontario spreads are shown for 2014-2017 in PUB/MH I-41a-b. The spreads over Ontario are shown to have hit a low of negative 10 basis points in mid-2014 for both 10 year debt and 30 year debt. Spreads increased to the range of positive 15 basis points about mid-2016 for 10 year debt, and 20 basis points for 20 year debt, and have since declined to about 15 basis points for 30 year debt and 10 basis points for 10 year debt.
[83] PUB MFR 44, page 2
[84] MIPUG/MH I-13a-b
[85]Actual debt guarantee fee paid by year from PUB/MH I-43a in the 2008/09 GRA, PUB/MH I-66a in the 2012/13 & 2013/14 GRA and PUB-MFR-55 in this proceeding.
[86] Inclusive of taxes such as GST

Government revenues, it is not clear that this effect wouldn't pose a larger risk to the Province's credit rating than the self-supported debt carried by Hydro that is proposed to be paid down.

In short, it is not clear that Hydro's proposed rate increases are needed to protect the government, nor whether such protection should be a key concern of ratepayers who are already paying a substantial debt guarantee fee. Further, there is basis for concern that the Hydro proposals have not been properly assessed by Hydro as to whether their impact on the Provincial Government may actually be a net negative, rather than some beneficial protection as asserted.

4.4 FINANCIAL IMPACTS OF A 7.9%/YEAR RATE INCREASE SCENARIO

Considering the full range of above factors arising from Hydro's plan, the case for Hydro's "view" that 7.9%/year rate increases are required does not bear out under scrutiny. This includes the fact that: a) there are, at best, likely limited impacts to Hydro's self-supporting status, b) no apparent customer benefits arising from higher rates that can be supported under a principled rate regulation regime, and c) at best, only unsupported concepts of protecting the Provincial Government (and unassessed risks arising to the Provincial Government revenues)

It is also beneficial to assess the financial condition that is expected to arise in the event Hydro is approved for the 7.9%/year scenario in the MH16 Updated with Interim per Appendix 3.8 (and related uncertainty analysis in PUB/MH I1-41a-b). The following outcomes are noted:

- In the event Hydro implements the rate increases in Appendix 3.8, Hydro will be targeting reserve levels (retained earnings) exceeding $6.5 billion by 2026/27. No scenarios have been provided to suggest ratepayers face risk scenarios that are commensurate with this level of reserves.
- Because the 7.9%/year rate trajectory drives rates to a high level (81% above today's level by 2027/28), net income sees continuing record levels of $650 million per year and up, with Hydro's financial targets (Interest Coverage and Capital Coverage) being far exceeded.[87] This is the basis for Hydro running scenarios that project a potential 24% decrease at that time[88] to bring financial ratios back down to more reasonable target levels.
- Hydro's risk scenarios[89] indicate that even a repeat of the worst recorded 5 year drought over the period 2019/20 to 2023/24 (i.e., before significant debt repayment has occurred, and with much of the drought occurring before the last of the 7.9%/year increases are even yet in place), net

[87] IFF16 Update with Interim, Appendix 3.8 – For example, in 2027 Hydro's equity ratio reaches 25%, its EBITDA interest coverage is at 2.36 and its capital coverage is 2.29. These all continue to increase such that by 2036 the equity ratio reaches 64%, EBITDA interest coverage is 5.52 and capital coverage is 3.23
[88] PUB/MH II-21a-b
[89] PUB/MH II-39

income over the 5 years of the drought would be positive by over $500 million. Retained earnings would grow over the course of the drought from $3.053 billion in 2018/19[90] to $3.581 billion[91] at the end of the drought in 2023/24. Under such rate levels, it is not apparent what role ratepayer funded reserves are expected to play, or why they would even be required.

- The uncertainty analysis[92] shows that by 2020/21, there is no year where even the 5th percentile conditions, combining bad droughts with adverse export price movements and poor interest rate conditions, would lead to any net loss for Hydro. In many years, the 5th percentile case leads to net income on the order of $200 million or higher.
- Under 50th percentile conditions, a sustained pattern of debt reduction begins even before Keeyask is fully in-service (2022/23 shows a small decrease in long-term debt)[93]. By 2026/27, the 50th percentile long-term debt has declined almost $3 billion, or over 10% of Hydro's total peak debt. As noted in Background Paper A on Manitoba Hydro Debt Levels,[94] Hydro has not previously sought net debt declines (at least since 1980[95]), much less over a focused period of 4-5 years during a time when the new projects are coming into service and face their most challenging economic conditions (capital intensive projects are almost universally high cost when brought into service, and move to a lower cost with time as the inflation-protected nature of the asset begins to bring real price benefits[96]).

Considering the above factors, it is apparent that a 7.9%/year trajectory is overly aggressive, achieves unreasonably high financial standards for a capital-intensive regulated utility, and is not needed nor justified to achieve a self-supporting utility consistent with Hydro's legislative mandate. The end result is excessive pressure on current day ratepayers tied largely to assets that need to be recognized as long-term resources to the system.

Assessment continues below of factors that inform the necessity of rate increases more in line with traditional projections for the test years.

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[90] Per Appendix 3.8
[91] PUB/MH II-39
[92] PUB/MH II-41a-b, page 7
[93] 50th percentile long-term debt declines from $23,551 million to $23,314 million per PUB/MH II-41a-b, page 10.
[94] Supplementary Background Paper A: Manitoba Hydro Debt Levels, prepared by P. Bowman on behalf of MIPUG, October 2017
[95] MIPUG/MH I-2g
[96] This can be seen, for example, in Hydro's Tab 2, page 25, Figure 2.21 where Keeyask operations show a material negative cash flow impact in 2023/24, but this improves each year through 2033/34 as the project sees small initial depreciation and reduction in carrying costs, and this trend will further continue as the nominal market value of the power produced by Keeyask increases with inflation or other factors.

5.0 THE 'PUB/MH I-34 ATTACHMENT 2' SCENARIO (3.95% AVERAGE RATE INCREASE)

This section reviews the sufficiency of the financial conditions shown in the rate increase scenario provided in PUB/MH I-34 Attachment 2. This scenario assumes the following:

1) All of Hydro's forecasts for MH16 Updated are included;
2) The 3.36% interim rate increases granted for August 1, 2016 and August 1, 2017, are both finalized; and,
3) A 3.95% average rate increase is granted for April 1, 2018, and assumed further 3.95%/year rate increases going forward to 2028/29 when 2% annual increases being to be implemented.

This is consistent with the scenarios provided in the Uncertainty Analysis in PUB/MH II-41a-b.

This section also assesses (and largely rejects) Hydro's claim that PUB/MH I-34 Attachment 2 is not reliable, since it assumes application of debt "terming" (use of shorter dated long-term debt, with lower costs) when such terming may not be possible under a 3.95% average rate increase scenario but only under the 7.9% rate increase scenario.

The section concludes that the above input assumptions and scenarios provided by Hydro show sufficient and acceptable financial performance, in line with Hydro's risk and mandate, and consistent with general expectations for the utility since at least the NFAT proceeding. This conclusion is tied to following complementary points:

1) If the input assumptions are not correct, and overstate Hydro's costs or fail to reflect appropriate accounting, regulatory or other policies, the 3.95% rate increase shown for April 1, 2018 would not be necessary in full to achieve the same financial outcome.
2) Should certain adverse conditions arise in the next few years, which are not part of the base PUB/MH I-34 Attachment 2 scenario, it is possible that somewhat higher rate increase may be required in future, but there is no indication that net benefits arise from targeting higher rate levels outside of, or in advance of, such adverse conditions.

In subsequent sections of this evidence (Section 6), it is shown that the 3.95% scenario provided by Hydro includes a number of assumptions and inputs that are either inappropriate or incorrectly applied, and that largely the same financial performance as shown in PUB/MH I-34 Attachment 2 (particularly net income and retained earnings) can be achieved even if a rate increase somewhat lower than 3.95% if granted for the 2018/19 year.

5.1 ASSESSMENT OF 3.95% RATE INCREASES FOR SUFFICIENCY

The scenario presented in PUB/MH I-34 Attachment 2 illustrates that key financial criteria over the long-term continue to largely track the scenarios as reviewed and approved at NFAT, as shown in the following figures,[97] focused on:

1) Figure 5-1: Hydro's costs that must be covered by domestic ratepayers (all regulatory accounting costs less export and other revenues) on a unit basis (i.e., average cents per domestic kW.h sold in that year).
2) Figure 5-2: Hydro's level of retained earnings
3) Figure 5-3: Hydro's level of long-term debt

Each figure shows the NFAT projections for Plan 5/6 (the development plan ultimately pursued) as a blue line and cone of probabilities (combining the NFAT LOW, REF, and HIGH sensitivity analysis conditions for export/fuel prices, capital costs and interest rates). Actuals to date are shown by the red solid line, and projections based on 3.95%/year increases are shown by the orange dashed line. Where shown, for reference, the projections with 7.9%/year rate increases are shown by a red dotted line.

The following figures are briefly summarized in this testimony – further background and conclusions are set out in Background Paper B in respect of comparing IFF16 to the NFAT projections

For reference, IFF14 (green) and IFF 15 (light blue) are also shown in some of the following figures where relevant. Looking to net costs of Hydro's system.

[97] These figures are further detailed in Supplementary Background Paper B: NFAT Update, prepared by P. Bowman on behalf of MIPUG, October 2017

Figure 5-1: Net Unit Cost of Hydro's Domestic System (before reserves) Under NFAT Plan 5/6 versus IFF16 (assuming 3.95% increase scenario)[98]

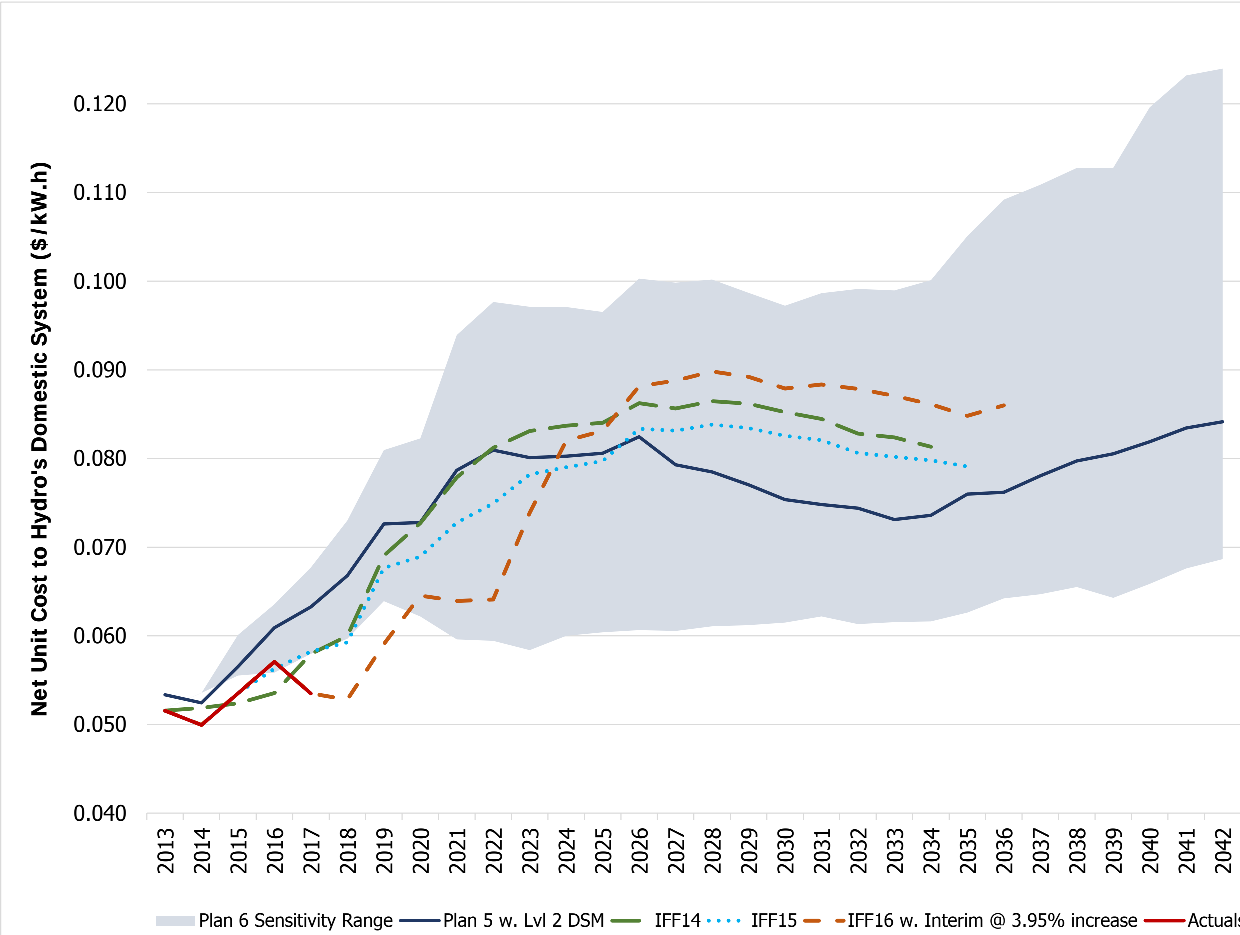


Figure 5-1 shows that since the NFAT projections were prepared, the net costs of Hydro's system (amounts that domestic ratepayers will be ultimately required to pay) of pursuing the development plan 5/6 have

[98] Calculated as Total Expenses each year less extra-provincial revenues and other revenues to represent expenses covered by domestic revenue then divided by corresponding domestic load forecast (less Power Smart Plan annual GWh savings). Plan 6 (K19/Imports/Gas/750MW) range includes 27 economic sensitivity analysis scenarios provided in Appendix 11.4 spreadsheets in NFAT Review divided by 2012 Base Load Forecast provided as Appendix of NFAT review (less 2013-2016 Power Smart Plan savings at Meter from Appendix E of NFAT), Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets divided by 2013 Load Forecast with Level 2 DSM Appendix D in NFAT (less 2014-17 PowerSmart Plan savings at meter page 56 of 86 Appendix 8.1 in 2015/16 GRA), IFF14 from Appendix 3.3 in 2015/16 GRA, 2014 Load Forecast Appendix 7.1 in 2015/16 GRA (less 2014-2017 PowerSmart Plan savings at the meter, Appendix 8.1 in 2015/16 GRA); IFF15 Attachment 1 in 2016/17 Interim Rate proceeding, 2015 Load Forecast Attachment 25 in 2015/16 Interim rates proceeding (less DSM savings – impact at meter, Attachment 24 in 2015/16 Interim rates proceeding); IFF16 with Interim at 3.95% rate increases from PUB/MH I-34 Attachment 2 divided by 2016 Load Forecast provided in Appendix 7.1 (uses weather adjusted actuals for 2015/16) less DSM savings at meter from Coalition/MH I-48a Attachment page 3 of 3. The above graph is based on costs not rates, but for reference in the NFAT review for Plan 6 the lowest cost range had 20 year rate increases of 1.69% and the highest cost range had rate increases of approximately 5.48% each year to get to debt ratios of 75% by 2031/32. Plan 5 in this scenario had annual rate increases of 3.99%.

remained below expectations through 2022/23 (and even below the best case scenarios shown by the blue shaded area through 2018/19, a function in part of the recent high water flows). As Keeyask comes into service (2023/24), the costs to which ratepayers are exposed is higher than expected under reference NFAT conditions through the end of the IFF period (blue line), but remains well within the cone of possibilities considered at the NFAT hearing for development plan 5/6. Note that the above figure is not capturing rates paid – it is plotting values derived by adding up all of the costs on Hydro's income statement less the export revenues that help pay these costs, and dividing by domestic sales (see Table 5-1 below). As shown in Table 5-1, there are numerous changes since NFAT that drive the change in values, including such factors as much lower export revenues and O&M, and somewhat higher depreciation expense, but the net effect is, for the most part, largely offsetting.

Over the longer-term, the above figure highlights that under each of the recent IFFs (IFF14, IFF15, and IFF16), the total costs of the system after Keeyask comes into service are somewhat higher than was projected at NFAT. Outside of known factors like capital cost increases, this is also being driven by two factors which are within Hydro's control, and which serve to reduce the comparability with NFAT forecasts:

1) The NFAT forecast used the less aggressive ASL method of depreciation for new major capital projects.[99] This would serve to depress costs compared to the now proposed ELG method, as further discussed in Section 6.2.2 below.

2) Changes in forecast DSM, which leads to both higher spending in the IFF16 scenarios, and lower net load on which to recover all of Hydro's costs (with limited benefits from added export revenues each year). Note that the NFAT assumptions already included substantial DSM under "Plan 2", which was the more aggressive DSM plan at that time. This matter is further discussed in Section 6.3 below.

Absent these two factors, the IFF scenarios in future would more closely resemble the costs under NFAT reference conditions (i.e., the IFF16 line would trend much closer to the NFAT cost profile line).

Figure 5-1 above also shows that IFF16 is not materially different than IFF14 and IFF15 in terms of long-term trajectory, and is better over the period to 2023/24. The PUB has already indicated these earlier IFFs are consistent with 3.36%-3.95% rate increases.[100]

[99] Transcript page 3339, 2013 NFAT proceeding.
[100] Order 73/15, pages 15 – 16 and Order 59/16 pages 7 - 9

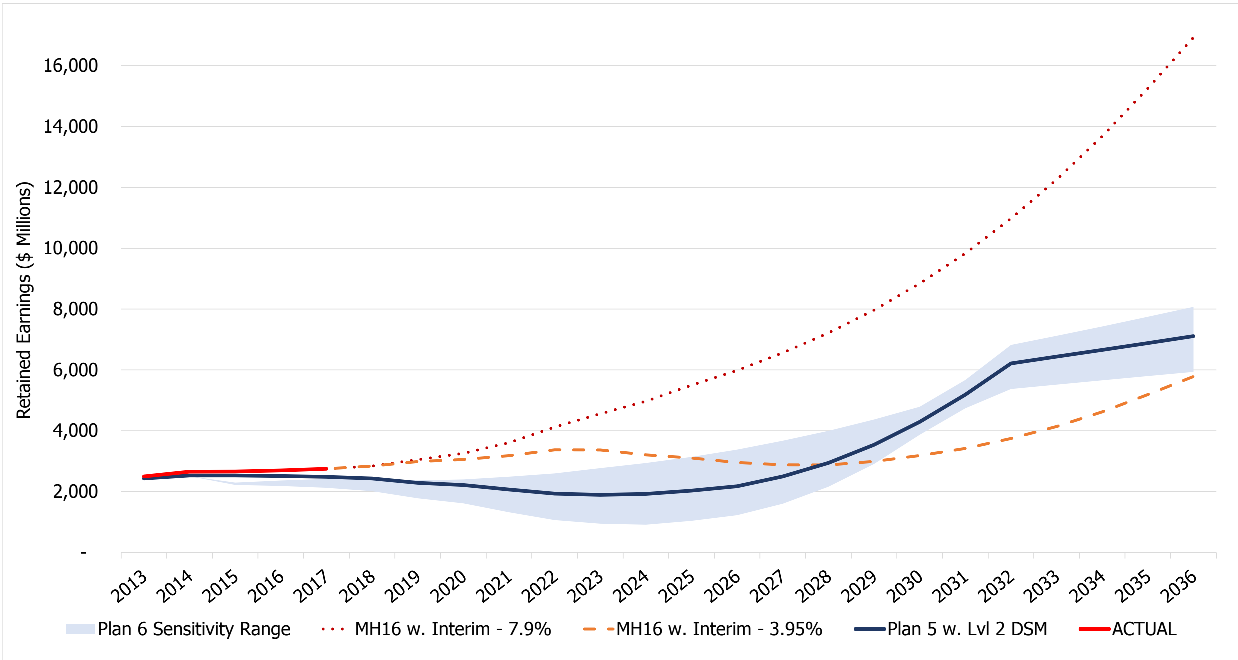
Table 5-1: Net Unit Cost of Hydro's System (before reserves) Calculation for NFAT Plan 5 versus IFF16 (assuming 3.95% increase scenario)[101]

$ Millions and GW.h	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
NFAT Plan 5 Level 2 DSM (Ex.MH-104-12-3 Update)																								
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711	724	738	752	768	780	793	815	832	852	870	887
Finance Expense	454	462	511	542	613	694	815	841	1,132	1,247	1,249	1,266	1,268	1,265	1,230	1,210	1,172	1,136	1,150	1,110	1,072	1,070	1,107	1,124
Depreciation and Amortization	408	439	433	463	476	505	543	553	631	675	682	683	687	696	701	695	693	694	717	729	712	707	729	730
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127	127	128	128	128	129	132	131	131	131	131	132
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266	259	273	275	287	295	284	313	325	344	360	350
Capital and Other Taxes	87	95	103	113	122	132	138	143	146	146	147	149	150	151	153	155	158	161	169	170	172	174	176	178
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7
Total Expenses	1,673	1,747	1,835	1,945	2,067	2,221	2,408	2,469	2,916	3,107	3,138	3,180	3,217	3,230	3,232	3,223	3,213	3,203	3,251	3,274	3,251	3,283	3,379	3,407
less: Export and other rev	371	423	398	388	446	507	538	587	869	981	1,010	1,023	1,023	958	1,019	1,006	1,010	1,016	1,050	1,055	1,041	1,029	1,019	1,010
Net costs to ratepayers	1,302	1,323	1,437	1,558	1,621	1,714	1,870	1,882	2,047	2,125	2,128	2,157	2,194	2,273	2,213	2,217	2,203	2,187	2,201	2,219	2,210	2,254	2,359	2,397
Domestic Sales (net of DSM)	24,404	25,239	25,422	25,577	25,624	25,663	25,747	25,857	26,021	26,258	26,567	26,880	27,221	27,566	27,914	28,251	28,603	29,015	29,425	29,827	30,229	30,636	31,048	31,465
Average net cost to ratepayers (before reserves)	0.0533	0.0524	0.0565	0.0609	0.0633	0.0668	0.0726	0.0728	0.0787	0.0809	0.0801	0.0803	0.0806	0.0824	0.0793	0.0785	0.0770	0.0754	0.0748	0.0744	0.0731	0.0736	0.0760	0.0762
MH16 Update with Interim (PUB/MH I-34 Attachment 2)																								
Operating and Administrative					536	518	501	511	513	524	536	548	559	571	583	595	607	620	633	646	660	674	688	702
Finance Expense					608	587	677	749	829	905	1,156	1,202	1,204	1,201	1,214	1,219	1,206	1,194	1,215	1,200	1,197	1,183	1,155	1,128
Finance Income					(17)	(17)	(21)	(28)	(35)	(33)	(37)	(15)	(12)	(14)	(16)	(17)	(16)	(16)	(15)	(17)	(17)	(21)	(22)	(23)
Depreciation and Amortization					375	396	471	515	555	597	689	714	726	739	752	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments					131	130	120	110	113	117	127	128	131	131	131	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased					132	124	140	158	165	156	140	135	138	127	129	131	134	138	147	129	128	134	143	133
Capital and Other Taxes					119	132	145	154	161	165	174	174	175	175	175	176	177	178	179	180	181	182	183	189
Other Expenses					60	116	109	481	94	92	71	64	67	71	76	79	84	87	87	89	91	92	95	96
Corporate Allocation					8	8	8	8	8	8	8	8	8	8	8	8	8	5	3	3	3	3	3	3
less: amounts previously paid through BPIII account					-	-	(3)	(79)	(79)	(79)	(79)	(26)	-	-	-	-	-	-	-	-	-	-	-	-
less: regulatory deferral					(66)	(72)	(114)	(464)	(71)	(64)	(43)	48	50	49	45	44	40	35	33	31	28	28	28	30
Total Expenses	1,407	1,439	1,525	1,649	1,886	1,922	2,033	2,115	2,253	2,388	2,742	2,980	3,046	3,058	3,097	3,132	3,148	3,163	3,220	3,216	3,244	3,266	3,279	3,280
less: Export and other rev	131	159	160	202	488	544	500	451	600	726	813	822	840	702	707	698	714	735	747	744	741	736	734	643
Net costs to ratepayers	1,276	1,280	1,365	1,447	1,398	1,378	1,533	1,664	1,653	1,662	1,929	2,158	2,206	2,356	2,390	2,434	2,434	2,428	2,473	2,472	2,503	2,530	2,545	2,637
Domestic Sales (net of DSM)	24,750	25,625	25,505	25,355	26,130	26,112	25,954	25,799	25,869	25,932	26,125	26,330	26,541	26,722	26,920	27,090	27,282	27,624	27,979	28,139	28,746	29,369	30,005	30,666
Average net cost to ratepayers (before reserves)	0.0516	0.0500	0.0535	0.0571	0.0535	0.0528	0.0591	0.0645	0.0639	0.0641	0.0738	0.0820	0.0831	0.0882	0.0888	0.0898	0.0892	0.0879	0.0884	0.0878	0.0871	0.0861	0.0848	0.0860

[101] Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets divided by 2013 Load Forecast with Level 2 DSM Appendix D in NFAT (less 2014-17 PowerSmart Plan savings at meter page 56 of 86 Appendix 8.1 in 2015/16 GRA). 2033/34 to 2035/36 load forecast estimated with annual growth equal to growth from 2032 – 2033, DSM savings held constant at 2029 levels from 2030 - 2036; IFF16 with Interim at 3.95% rate increases from PUB/MH I-34 Attachment 2 divided by 2016 Load Forecast provided in Appendix 7.1 (uses weather adjusted actuals for 2015/16) less DSM savings at meter from Coalition/MH I-48a Attachment page 3 of 3. DSM savings held constant at 2032 levels from 2033 to 2036.

Looking to retained earnings, the forecasts are summarized in Figure 5-2 below.

Figure 5-2: Retained Earnings of NFAT Plan 5/6 versus IFF16[102]



As shown in Figure 5-2 above, the retained earnings under the updated 3.95% scenario largely tracks the scenario as projected at the NFAT hearing, with 2 major exceptions: first, the timeline for reaching the minimum point of retained earnings is delayed about 4-5 years (from about 2023 to 2027/2028), and second, the minimum point attained is significantly higher in the updated scenario, at $2.9 billion versus $1.9 billion in the NFAT reference case. Of note is that the updated 3.95%/year scenario shows a lowest series retained earnings at $2.9 billion, while even the best case scenario reviewed at the NFAT hearing (to top of the blue shaded area) spent 10 years without exceeding $2.6 billion in retained earnings. This serves as added short-term risk protection for ratepayers relative to what was considered in the NFAT for this time period.

The matter of a delayed minimum point for retained earnings, and a delayed path towards the $6 billion level is consistent with, and largely driven by, delays in getting the projects in service compared to the NFAT assumptions (particularly Keeyask). For this reason MH16 does not achieve a 75% debt ratio by the 2031/32 date targeted in NFAT, but approximately 5 years later.[103] Given the pattern of delays and benefits

[102] Plan 6 (K19/Imports/Gas/750MW) range includes 27 economic sensitivity analysis scenarios provided in Appendix 11.4 spreadsheets in NFAT Review, Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets, IFF16 with Interim at 3.95% rate increases from PUB/MH I-34, IFF16 with Interim at 7.9% rate increases from Appendix 3.8

[103] PUB/MH I-34 Attachment 2 shows the debt ratio at 77% by 2035/36 and declining by about 2% per year.

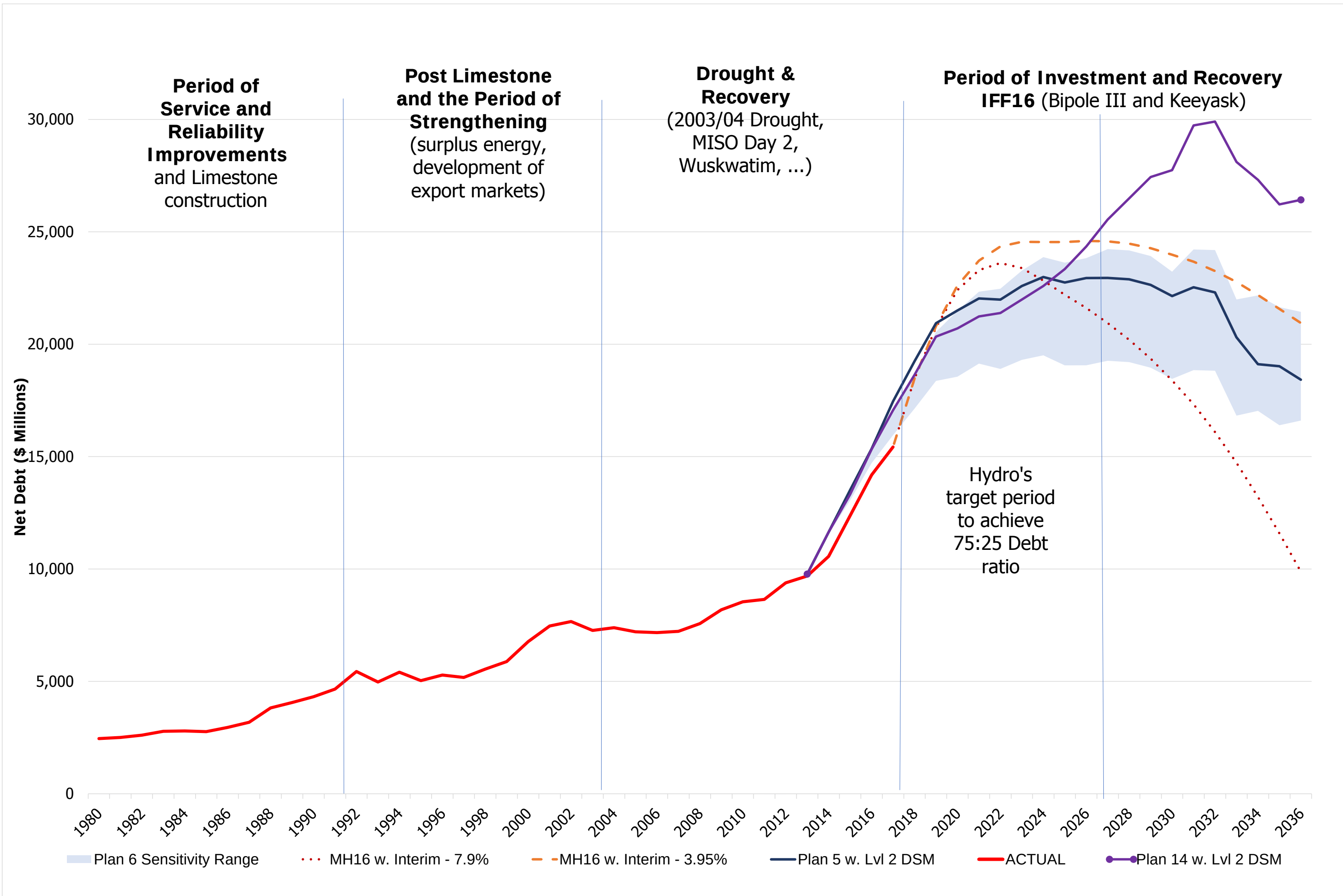
shown in Figure 5-2 (including the much higher minimum equity point), it is not apparent that this represents an unfavorable development compared to the NFAT scenarios.

Figure 5-2 also provides a comparison to the MH16 Update with Interim forecasts (increases of 7.9%/year), which are further discussed in Background Paper B – NFAT Update.[104]

The final comparison of NFAT scenarios to the updated 3.95%/year projections relates to the total long-term debt, and is shown in Figure 5-3 below.

[104] Supplementary Background Paper B: NFAT Update, prepared by P. Bowman on behalf of MIPUG, October 2017

Figure 5-3: Manitoba Hydro Net Debt under NFAT Scenarios and Updated IFF Scenarios at 3.95% and 7.9%[105]



[105] Plan 6 Sensitivity Range (K19/Imports/Gas/750MW) includes 27 economic sensitivity analysis scenarios provided in Appendix 11.4 spreadsheets in NFAT Review, Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets, IFF16 with Interim at 3.95% rate increases from PUB/MH I-34 Attachment 2, Actuals 1980-2017 from PUB MFR 15 and MIPUG/MH-I-2g. Plan 6 sensitivity ranges and Plan 5 adds $500 million each year as an estimate of total long-term debt including the normal current portion of LTD, based on annual report $2.5 billion over 5 years 2017-2022.

Figure 5-3 above continues to show the NFAT recommended approach and risk range in blue, the MH16 Update with Interim at 3.95% in orange, the Hydro 7.9%/year proposal in red, and, for reference, the Hydro 2013 Preferred Development Plan in purple. The figure also shows the debt values going back to 1980 for long-term context. A detailed discussion of this figure is presented in Background Paper A.[106]

The critical conclusions out of Figure 5-3 is the extent to which Hydro's forecasts under both NFAT and the updated scenario with 3.95% both follow a pattern consistent with the long-term history of Hydro; that is, maintaining debt at relatively consistent levels between periods of debt growth, such as Limestone in the early 1990s or Wuskwatim in 2006-2012, with intervening periods of consolidation but not typically debt reduction.

The specifics of the updated 3.95%/year increase scenario do show higher levels of debt than under the NFAT analysis, topping out near the same maximum at the worst of the risk range from NFAT ($24.215 billion in 2030/31),[107] Despite this higher debt level, as shown in Table 5-1 previously, finance expense over the long-term (following Keeyask in-service) tracks very closely to the NFAT levels. There is no tendency for the debt to grow after 2027, when, in fact, reductions become possible, entirely consistent with a pattern of modest debt retirement. This is only three years after Keeyask's in-service.

In short, the above scenarios show that compared to the detailed NFAT reviews, financial projections with a 3.95%/year rate increase scenario today show beneficial trends over the period to about 2023/24, with some adverse trends over the long-term, largely within the risk ranges considered at the NFAT proceeding. Given this has been achieved while materially reducing the risk exposure with time (as more and more capital costs for Keeyask and Bipole III and locked in, and debt is borrowed at fixed rates), and is driven in part by as-yet unfinalized plans to pursue uneconomic DSM at Hydro's cost (e.g., rather than using external funding), this should be viewed largely as a neutral development.

In relation to more recent forecasts, it is clear the forecasts in this GRA generally compare favorably with the forecasts last reviewed by the Board, in IFF15. MIPUG's 2017/18 Interim Rate submission (Exhibit MIPUG-4) set out a detailed comparison between IFF16 to IFF15[108] showing that the net costs to ratepayers over the first 11 years of the previous IFF to the current IFF (maintaining a consistent rate increase scenario) are nearly identical (within $46 million on over $20 billion of costs that will be paid by domestic ratepayers)[109].

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[106] Supplementary Background Paper A: Manitoba Hydro Debt Levels, prepared by P. Bowman on behalf of MIPUG, October 2017

[107] Appendix 11.4 from NFAT, Plan 6 (K19, Imp, Gas, 750MW) High-Low-High scenario, with $500 million added to represent current portion of LTD.

[108] Ex. MIPUG-4, page 15

[109] Ex. MIPUG-4, page 3

The clear conclusion from the above material is that financially, the outcomes of PUB/MH I-34 Attachment 2 represent a pathway that is sound in terms of the earlier NFAT expectations, and largely consistent with the trajectory that was acceptable to the Board in its review of IFF15, which it also parallels. In each case, the more updated forecast shows some adverse movements (such as somewhat higher long-term debt levels over certain periods of the 20 year projection) combined with positive developments (such as reduced exposure to interest rate moves and capital cost uncertainties, and higher retained earnings for most of the first 10 years of the forecast). In the event these conditions unfold as per MH16, and updated assessments of risks indicate the potential for higher costs to persist, rate increases somewhat higher than average can be considered at that time.

Further support for the sufficiency of PUB/MH II-34 Attachment 2 is shown with reference to the Hydro's capital coverage ratio. This financial target metric is maintained at or above target (1.2) for the entire 20 year forecast, and well above the critical 1.0 level. This 1.0 level is a key measure during the early consolidation period following the in-service of a new major plant, indicating the utility is cash positive, can maintain operations and focus on debt management.

5.2 PLANS REGARDING REDUCING THE WEIGHTED AVERAGE TERM TO MATURITY OF DEBT

PUB/MH I-34 Attachment 2 includes underlying input assumptions that new debt issued will follow a 12 year Weighted Average Term to Maturity ("WATM"), rather than Hydro's more typical forecasting of a 20 year WATM. This serves to reduce interest costs compared to the 20 year WATM. Hydro runs this scenario as part of PUB/MH I-34 Attachment 2, but suggests this scenario may be internally inconsistent, in that it models both a 3.95%/year rate increase regime and a 12 year WATM, which Hydro notes it potentially cannot pursue if only granted 3.95%/year rate increases (only with 7.9%/year). This section review whether the two inputs are in fact inconsistent, and whether a 12 year WATM (and the interest cost benefits it brings) must be abandoned in favour of a 20 WATM if rate increases other than 7.9%/year are granted.

Hydro's submission describes the utility's activities in the debt markets in Appendix 3.5 (Debt Management Strategy), and notes that in recent years Hydro has had to adapt its strategies to reflect the realities associated with the major borrowing program for capital development. The appropriate mix of debt of various forms is dependent on many conditions, including utility financing requirements, capital spending, debt market conditions, the yield curve, and extent to which lenders favour particular products at a given point in time. Unique among these factors is Hydro major borrowings required over the past few years and until 2021/22 to fund the large spending years at Keeyask and Bipole III.

In general, Hydro's actions as described are sensible and appropriate for the circumstances (i.e., a period with major borrowing commitments occurring in the next few years, with historically low interest rates, and with favorable access to lenders who prefer long dated bonds):

- Hydro increased the average term to maturity of the debt that it financed starting modestly in 2009 and more notably in 2013 to bring the corporate-wide WATM to above 18 years[110]. This compares to a historical WATM range of approximately 12-14 years that had largely been maintained since the early 1990s[111] (outside of a short period in the late 1990s when Hydro took advantage of what was thought to be a unique yield curve condition to materially raise the WATM through the use of swaps[112]). This increase reflects 2 purposes. One is to ensure that as little debt as possible has refinancing requirements concurrent with the massive borrowing needed in the high spend Keeyask and Bipole III years. The second is to take advantage of very low long-term interest rates and investor appetite over that period for long dated bonds. To implement this, Hydro issued debt in many years with WATM for those years averaging well above the 20 years that Hydro typically uses for projection and budgeting purposes.[113]
- Hydro reduced its holding of debt which is at risk of interest rate moves within 12 months below the target levels. The established guidelines set a target short-term and floating rate debt at 15-25% of the total debt portfolio, and an exposure to refinancing of long-term debt within 12 months to no more than 15% of the total debt portfolio[114], and Hydro has indicated their policy of a combined maximum of 35%[115]. As at March 31, 2014, the combined total stood at 26%[116]. By March 31, 2017 this combined percentage stood at 8%[117], which was both a material decline and well below target levels. The reason for this intentional decline is the high degree of annual borrowings anticipated – when the expected new borrowings to fund capital over the next 12 months are added to the existing debt exposed to interest rate risk, the combined total borrowings, which can be affected by interest rate moves in the next 12 months as of March 31,

[110] Appendix 3.5, Chart 7
[111] MIPUG/MH I-13a-b.
[112] MIPUG/MH II-19a-c.
[113] For example, see Appendix 3.7 from 2015/16 & 2016/17 GRA, Debt Management Strategy, page 9, which notes that in 2013/14 the WATM of new debt was 28 years.
[114] Appendix 3.5 page 13.
[115] PUB/MH I-28a-c page 4. Also Appendix 3.7 from 2015/16 & 2016/17 GRA, Debt Management Strategy, page 9.
[116] Appendix 3.7 from the 2015/16 and 2016/17 GRA, Debt Management Strategy, Chart 7
[117] Appendix 3.5, Chart 9.

2017 is 22%.[118] This is still well below the maximum permitted, but is consistent with the stated market conditions.

On balance, the above actions appear appropriate for the conditions experienced.

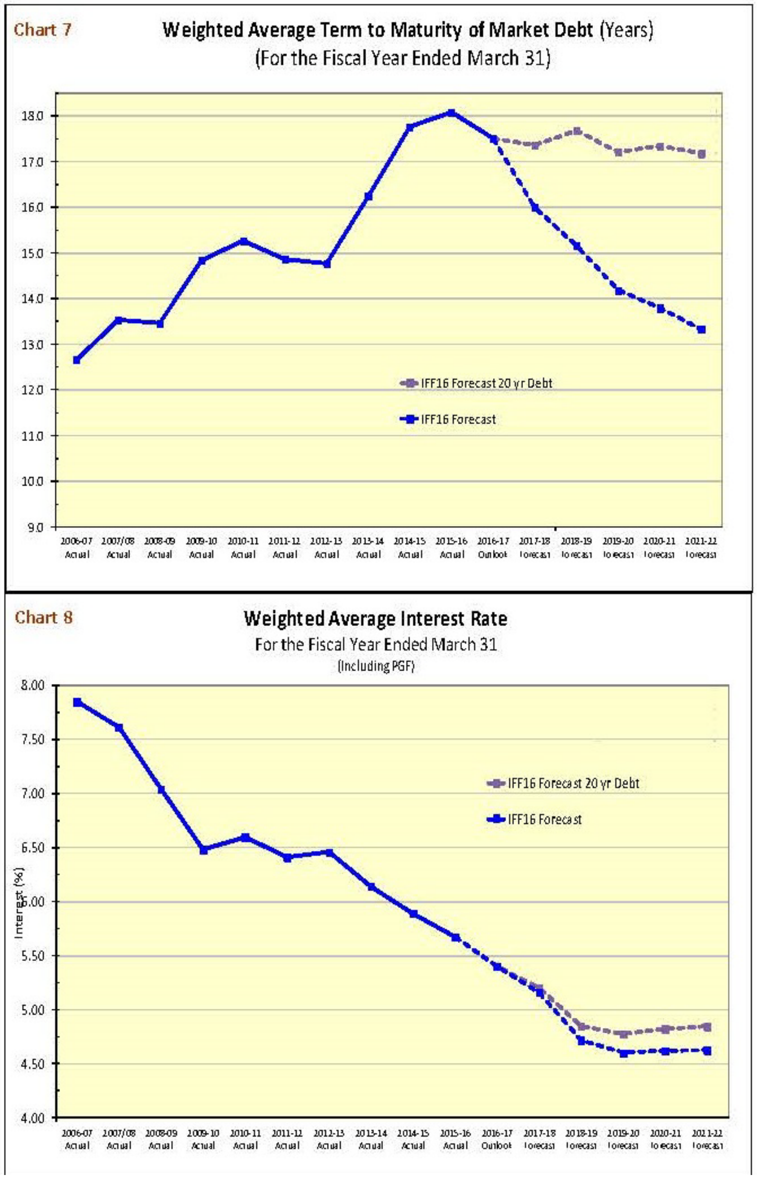
Note that the above policies were developed in part under the watch of the PUB, which received evidence on this matter from experts during the 2010/11 and 2011/12 GRA from National Bank Financial[119] (in response to a PUB directive from the 2008 GRA)[120] and from the Coalition.[121]

With this GRA, Hydro has now proposed to begin implementing a new phase of its borrowing program, which includes "terming" of the debt issuances during the 2018-2020 period[122]. The focus of the new phase is that Hydro is approaching a period where the major borrowings for Bipole III and Keeyask capital will decline, starting within the next 5 years. In addition, Hydro's cash flows will begin to improve as major capital projects come to an end and rate increases continue to be imposed. This gives the opportunity to issue more long-term debt with shorter maturities (matures sooner), for example within 5-10 years. Such debt is not only more flexible in that it allows Hydro to pay the balances off if cash generation is positive at the time the debt comes due, but it also comes at a lower interest rate than the very long-dated debt. Concurrent with implementing this strategy, Hydro has projected its interest costs for IFF16 on the basis of 12 year WATM debt being issued rather than the previous 20 year assumption[123].

The effect of this strategy is shown in Charts 7 and 8 from Appendix 3.5, reproduced below.

[118] Appendix 3.5, Chart 10. This is still well below Hydro's target of 35%, but with historically low interest rates that are projected to rise in the near term, an unusually high near-term uncertainty for Hydro's finances tied to capital project costs and borrowing costs, and a high degree of market access needed to finance the capital programs in the next few years, a tendency towards the low end of exposure on this variable is directionally appropriate.
[119] 2010/11 and 2011/12 GRA, Appendix 13.3
[120] PUB Order 116/08, page 80.
[121] Evidence of John D. McCormick, December 10, 2010.
[122] Appendix 3.5, page 17.
[123] Hydro does not appear to have proposed any specific update to the target policy percentages per se, though it does note plans to maintain the floating portion of the debt at or below 10% through 2020, per Appendix 3.5 page 21.

Figure 5-4: Weighted Average Term to Maturity Market Debt and Interest Rate[124]

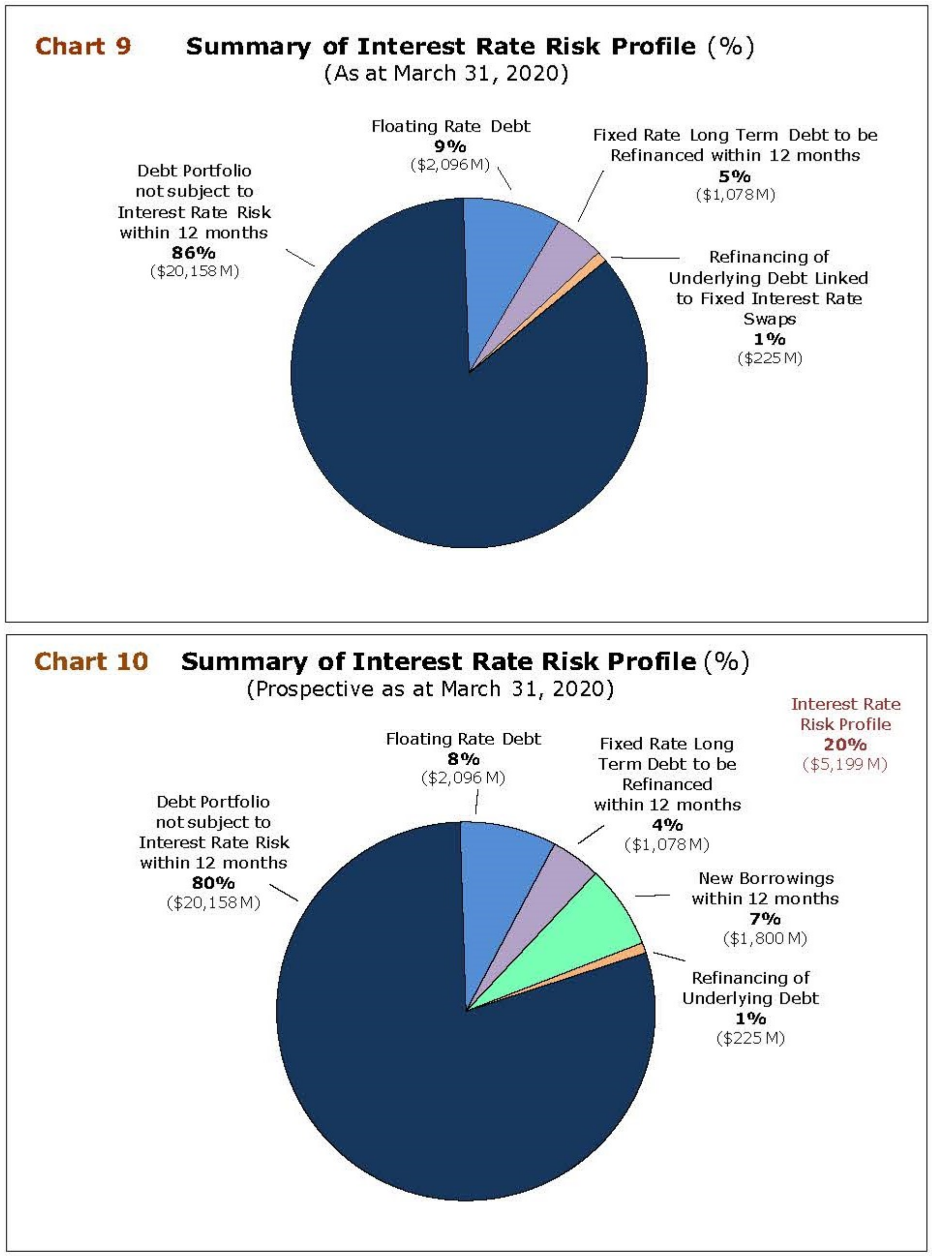


As shown in Figure 5-4 above, the excerpts from Hydro's Debt Management Strategy highlight the increase in WATM which was targeted in the years before the largest construction spending, and the new strategy to reduce the WATM commensurate with planning for the end of the major spending years. The lower portion of the figure shows that despite increasing the WATM, Hydro has been able to continue to bring the overall average interest rate on debt down throughout the period 2009-2015. It also highlights that with the planned WATM decline, the average interest rate will see measurable benefits compared to a default assumption of 20 year WATM debt being issues in future years.

[124] Appendix 3.5: MH 2017 Debt Management Strategy, page 12

Finally, in respect of Hydro's proposed approach, Figure 5-5 below shows the mix of debt forecast to be in place as at March 31, 2020 if the debt terming is undertaken, both without (Chart 9) and with (Chart 10) the next 12 month borrowing for capital spending included.

Figure 5-5: Summary of Interest Rate Risk Profile[125]



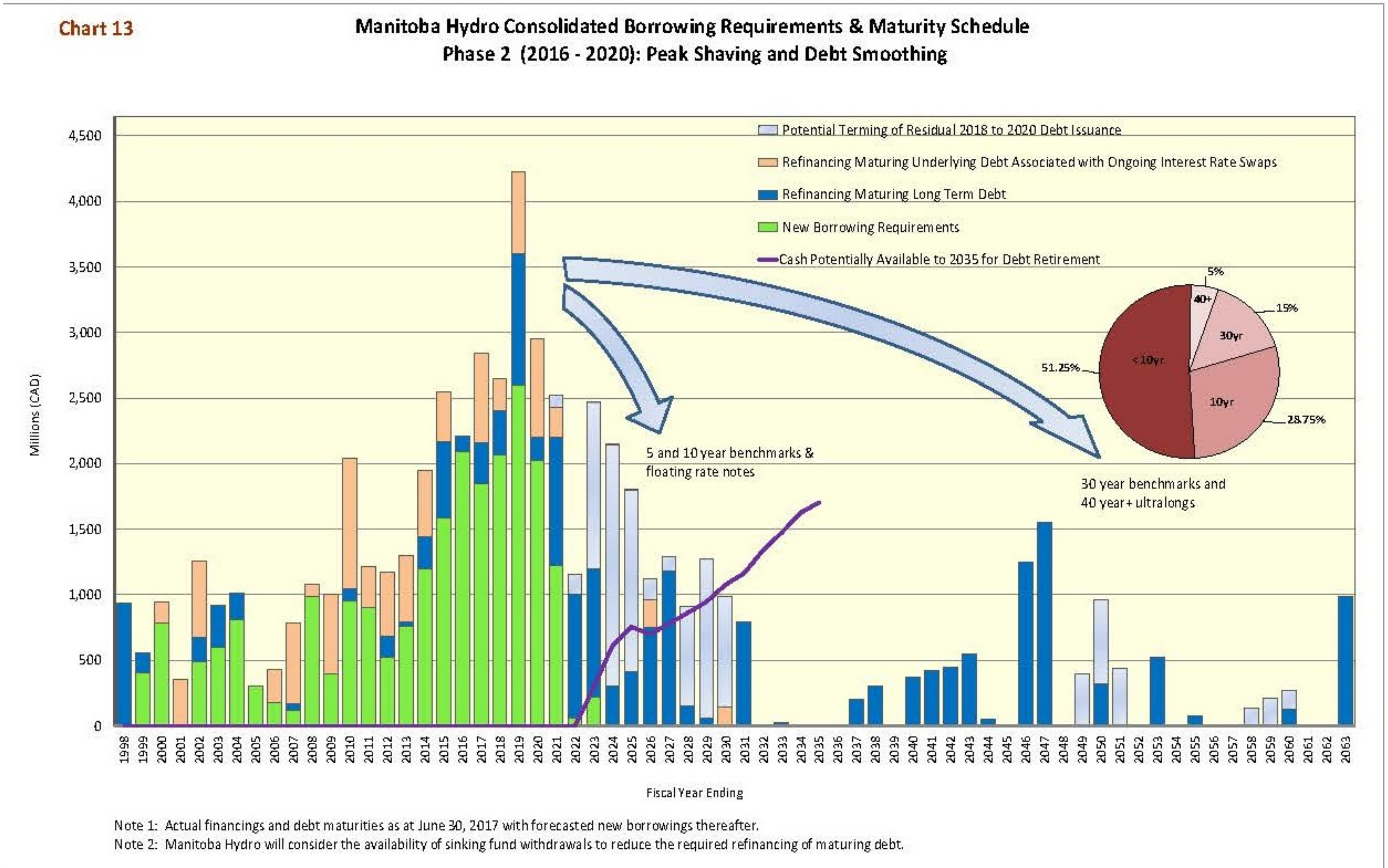
As shown in Figure 5-5 above (Chart 9), under Hydro's proposed terming, a total of 15% of Hydro's debt balance will be exposed to interest rate changes over the 12 months following March 31, 2020 (9% as

[125] PUB/MH I-128a, updates on Charts 9 & 10 from Tab 3.5: MH 2017 Debt Management Strategy for planned mix of borrowings and projected interest rate risk profiles

floating debt, 5% as fixed rate debt coming due, and 1% from debt linked to interest rate swaps). Once new debt for capital to be issued in the 12 months following March 31, 2020 is included (which is similarly exposed to interest rate risk) the total debt exposed comes to 20%. While this represents a substantial dollar value ($5.199 billion), it is well within the range Hydro has traditionally exposed to interest rate changes.

Finally, noting that the above Figure 5-5 shows the situation only at March 31, 2020, it is important to consider the full range of interest rate reset risk that Hydro is exposed to over the terming period. The best available data on this risk is set out in Figure 5-6 below, which is a replication of Hydro's Chart 13 from the Debt Management Strategy updated to 2016 Update with Interim.

1 **Figure 5-6: Manitoba Hydro Consolidated Borrowing Requirements & Maturity Schedule based on MH Update with Interim**[126]



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[126] MIPUG/MH I-20e

Figure 5-6 above shows the debt that must be refinanced by year in the event it is not repaid. The green bars relate to new capital borrowing requirements, which are largely complete by 2020/21. The dark blue bars are maturing long-term debt, and the orange bars are refinancing tied to swaps. The light blue bars are the new proposed terming strategy. Note that most of these components are the same as in the pie chart style of Charts 9 and 10 above, with the exception that Charts 9 and 10 also include interest rate risk on floating rate debt which is not up for refinancing (and therefore is not shown in Figure 5-6). Figure 5-6 clearly highlights the heavy borrowing required through the 2020/21 year for Keeyask, and also the far more limited borrowing requirements that arise after that time, absent terming. Specifically, if Hydro were not to use the terming strategy, the total debt to be refinanced after 2022/23 is only $3.7 billion over the next 10 years, or slightly over 15% of the total debt balance over a decade (recall that the policy allows up to 15% in a single year).

The other key aspects of Figure 5-6 is the purple line, which shows the cash surplus that is available to retire debt under this scenario (2016 Update with Interim, and 7.9%/year increases). As is clear from the comparison of the line and the bars, during a significant part of this period, under this forecast scenario, Hydro will have sufficient cash that none of the debt noted will have to be re-issued (all years from 2029/30 onwards, where the purple line is higher than the sum of all of the bars in that year). The values provided in MIPUG/MH I-20a-h show that over the period 2023 to 2035, surplus cash of $13.3 billion will be generated (the purple line) which nearly equals the total of all debt to be issued over that period (the sum of all of the bars is $14.0 billion) though timing is somewhat mismatched, as shown in Table 5-2 below:

Table 5-2: Values for Borrowing Requirements and Surplus Cash 2022/23 to 2034/35 under 7.9%/year rate increase ($ Millions CAD)

Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash	Net New Borrowings
2022	-	943	57	158	-	1,158
2023	-	980	220	1,270	294	2,176
2024	-	300	-	1,848	614	1,534
2025	-	412	-	1,390	755	1,046
2026	215	750	-	158	699	424
2027	-	1,178	-	111	779	509
2028	-	150	-	762	862	49
2029	-	60	-	1,214	946	328
2030	131	10	-	848	1,075	(87)
2031	-	796	-	-	1,163	(367)
2032	-	10	-	-	1,337	(1,327)
2033	-	30	-	-	1,474	(1,444)
2034	-	-	-	-	1,624	(1,624)
2035	-	10	-	-	1,704	(1,694)
	346	**5,628**	**278**	**7,759**	**13,326**	**684**

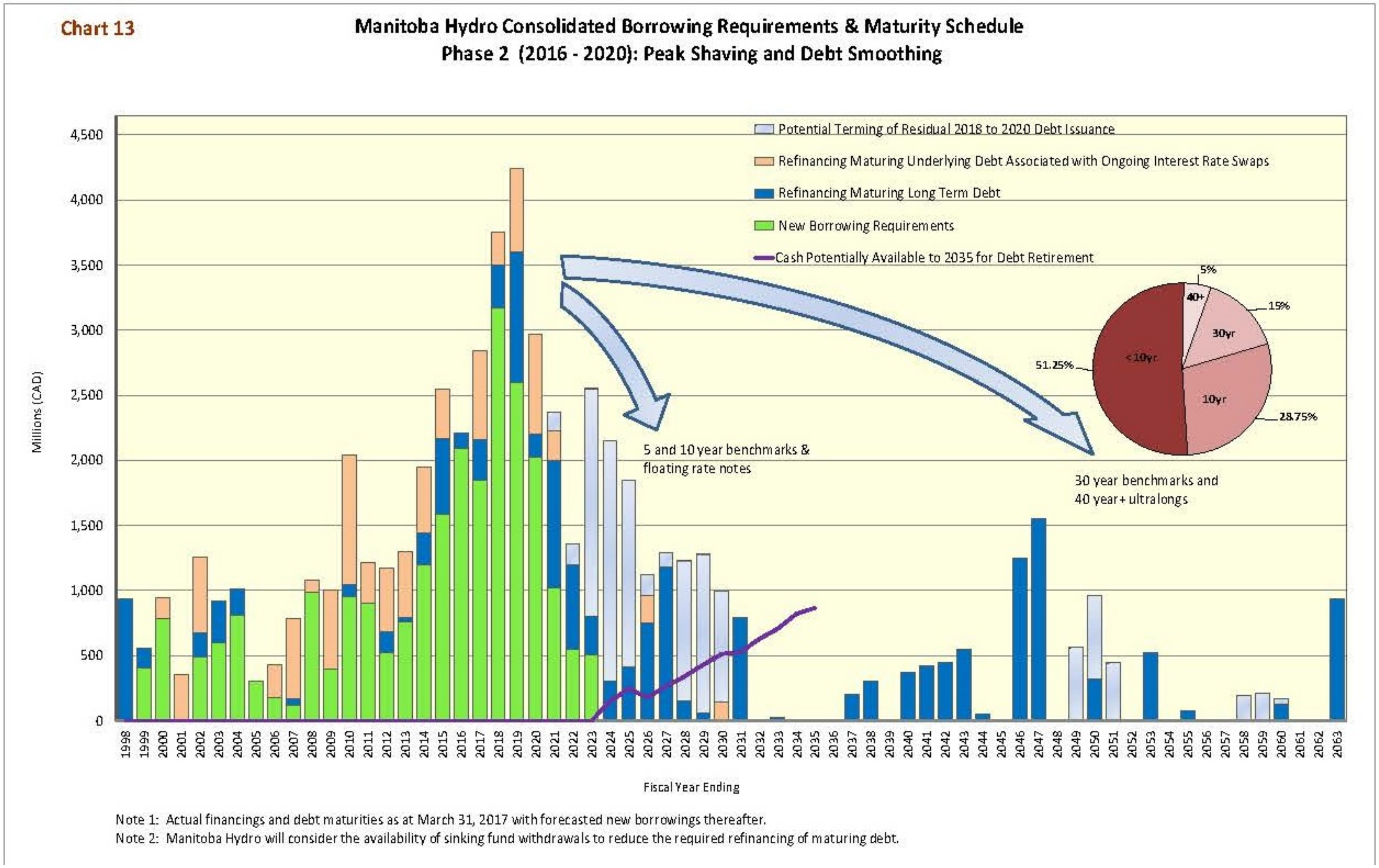
In short, under Hydro's plans with 7.9%/year rate increases, outside of some limited further terming, almost no debt of any form would need to be issued over that 12 year period. Hydro does indicate that it would retain floating rate debt within the target range of 15-25%[127], but this appears to be the only component that would be exposed to interest rate changes. As a result, Hydro's plans show an unusually low percentage of interest rate risk following 2020, well below the policy levels of up to 35%.

With that background, the critical question for this GRA relates to whether, absent the 7.9% rate increases being granted, would Hydro have to abandon this terming strategy (along with the cost savings it achieves in terms of a lower Weighted Average Interest Rate) and revert to a higher cost debt structure? This is consistent with Hydro's assertion that: "Should underlying forecast assumptions (including rate increases, cost savings, export prices, interest rates, in-service dates) not materialize as planned, Manitoba Hydro will re-evaluate and adjust its debt management strategy and the targeted weighted average term to maturity of new debt issuance as it deems necessary. All else being equal, it is expected this would erode the interest savings opportunity from a shortened maturity profile."[128]

The forecast borrowing requirements under a 3.95%/year rate increase scenario is shown below, as Figure 5-7.

[127] Appendix 3.5, page 21
[128] PUB/MH I-28a-c, page 5.

Figure 5-7: Manitoba hydro Consolidated Borrowing Requirements & Maturity Schedule Based on MH16 with 3.95% /year rate increases[129]



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[129] MIPUG/MH I-20f

Figure 5-7 above shows the borrowing requirements[130] assuming terming is undertaken and a 3.95%/year rate increase scenario is implemented. The figure shows that cash generation is reduced compared to the 7.9%/year scenario, as would be expected. Of note, the terming continues to be focused on debt that would come due in 2022/23 and beyond, and that some of this debt would be available for retirement by surplus cash (the purple line). The values from Figure 5-7 above for the key 2021/22 to 2034/35 period are shown in Table 5-3 below.

Table 5-3: Values for Borrowing Requirements and Surplus Cash 2022/23 to 2034/35 under 3.95%/year rate increase ($ Millions CAD)[131]

Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash	Net New Borrowings
2022	-	653	547	159	-	1,359
2023	-	296	504	1,752	-	2,552
2024	-	300	-	1,854	150	2,004
2025	-	412	-	1,439	247	1,603
2026	215	750	-	159	179	945
2027	-	1,178	-	111	265	1,024
2028	-	150	-	1,078	340	888
2029	-	60	-	1,218	430	848
2030	131	10	-	853	513	482
2031	-	796	-	-	527	268
2032	-	10	-	-	628	(618)
2033	-	30	-	-	707	(677)
2034	-	-	-	-	822	(822)
2035	-	10	-	-	866	(856)
	346	**4,655**	**1,051**	**8,624**	**5,674**	**9,001**

As shown in Table 5-3, the 3.95% scenario generates $5.7 billion in surplus cash compared to $14.7 billion in debt to be refinanced ($0.3 billion swap, $4.7 billion from long-term debt maturities, $1.0 billion from new borrowings for capital, and $8.6 billion tied to the terming strategy), a shortfall of $9.0 billion over 12 years (for reference, the 7.9% scenario shown above would retire basically all debt that comes due in the period 2023-2035). This is the portion of Hydro's long-term debt that would be subject to interest rate risk during the period.

The worst year in Table 5-3 above is 2022/23, which would expose $2.5 billion to interest rate changes in one year, made up of LTD maturities of $0.3 billion, new borrowings of $0.5 billion, and the first of the

130 Appears to use IFF16 – a version with MH16 Updated with Interim was not prepared.
131 Values provided in MIPUG/MH I-20f

new "termed" debt maturing, at $1.8 billion.[132] In this year, Hydro's total long-term debt stands at somewhat over $22.3 billion[133], so the debt at risk of interest rates is on the order of 10-11%, not counting whatever floating rate debt Hydro may elect to carry. Assuming Hydro continued to maintain floating rate debt at the lower levels consistent with the policy (15-25%), and not below the policy level as has been done recently, the combined debt at risk of interest rates within 12 months could be on the order of 25%, well below the policy maximum of 35%. And this is in the worst year of the terming period. For most of the remainder of the period, the debt at risk of interest rates is well below 5%, and is negative after 2031/32. Further, the worst year noted could readily be avoided by a small revision to the terming strategy to avoid significant maturities in 2022/23 and 2023/24, using slightly less 5 year debt in the next 1-2 years.

Were the terming not pursued, and the $9.0 billion of debt shown issued more conventionally at a WATM of 20 years or more, Hydro would have effectively no net debt issued over this 14 year period, and would have issues with cash management in many years as surpluses build with little long-term debt to retire.

In short, subject to the usual monitoring of market conditions, it appears appropriate and reasonable (indeed necessary) for Hydro to continue to monitor terming opportunities. Absent pursuing such opportunities, were Hydro to stick to the practice of issuing WATM 20 year debt over the next few years, it is clear Hydro would see material cash surpluses following Keeyask coming into service (even under the 3.95%/year scenario). In fact, the Debt Management Strategy highlights this very issue at page 1, where it notes: "It is vital that Manitoba Hydro's debt profile provide this off-ramp opportunity with shorter maturities because it is expensive and cumbersome to retire long-dated debt permanently." In other words, it is not that the conditions and rate increases permit Hydro to pursue terming, it is that they effectively require it to prevent significant cash management problems, as follows:

- Under a 7.9%/year rate increase scenario, there is so much cash generated in 2021/22 to 2034/35 that $14 billion of debt must be kept at-the-ready to be repaid by surplus cash, with effectively no new long-term debt issued over the period. Even with this strategy, Hydro's exposure to interest rates and debt turnover will be at atypically low levels, well below the target range permitted. If good conditions arise (e.g., good water, export prices), Hydro could be burdened with sufficient surplus cash that no further debt is available to be repaid without incurring a cumbersome and expensive process of retiring long-dated debt that is not otherwise coming due for many years.
- Under a 3.95%/year rate increase regime, the cash generated will permit significant debt to be repaid, but a terming strategy is necessary to permit the normal and targeted range of debt

[132] New borrowings of $0.5 billion,

[133] Per PUB/MH I-34 Attachment 2. Note this only includes the long-term portion, not the debt due within one year (which is a current liability on the IFF reports), so the total would be higher.

retirement and reissuance turnover, and to permit return to a more traditional WATM range of 12-14 years.

The numbers above suggest that at a scenario similar to PUB/MH I-34 Attachment 2, it is possible that Hydro would need to revise the terming strategy to a small degree, avoiding excessive 5 year debt issued in the next 1-2 years. This may mean that the 12 year WATM would be increased to a small degree, potentially at a small cost to interest expense. However, this would at most be a modest change to the terming strategy proposed, and the vast majority of the terming benefits would continue to accrue. There is no reason to expect that the bulk of the interest rate benefits arising from Hydro's terming strategy must be foregone in the event the Board rejects the move to a 7.9%/year rate increase regime.

6.0 ISSUES WITH INPUTS AND ASSUMPTIONS IN THE 3.95% RATE INCREASE SCENARIOS

This section focuses on items where Hydro's forecasts require testing for unreasonable inputs and assumptions, which would suggest that a comparable overall financial performance as set out in the 3.95%/year rate increase scenario (PUB/MH I-34 Attachment 2) can be achieved with a somewhat lower rate increase than 3.95%.

Such a conclusion would work in support of recommendations that the full 3.95% increase is not required to achieve the financial outcomes noted above (e.g., retained earnings levels that largely parallel, though slightly trail, the forecasts reviewed at NFAT). Items to be reviewed include:

- Section 6.1: Operating and Administrative ("O&A") cost estimates that are significantly improved since the last GRA, but which do not yet reflect a clear benchmark to past periods, such as 2011/12 (or earlier examples), when the PUB was already expressing concern over Hydro's cost growth. O&A costs in the current filing still show a level well above inflationary growth compared to the past periods. It would not be surprising to find that a thorough review of Hydro's costs may yet yield further savings than estimated by Hydro in the current GRA. Such cost control should be encouraged.
- Section 6.2: Regulatory deferral accounts that are not being applied in a manner consistent with prior Board directions and sound regulatory principles, most notably:
  - The regulatory deferral for capitalization of O&A overheads
  - The regulatory deferral associated with the adverse impacts of the use of the Equal Life Group ("ELG") procedure for calculating depreciation expense.

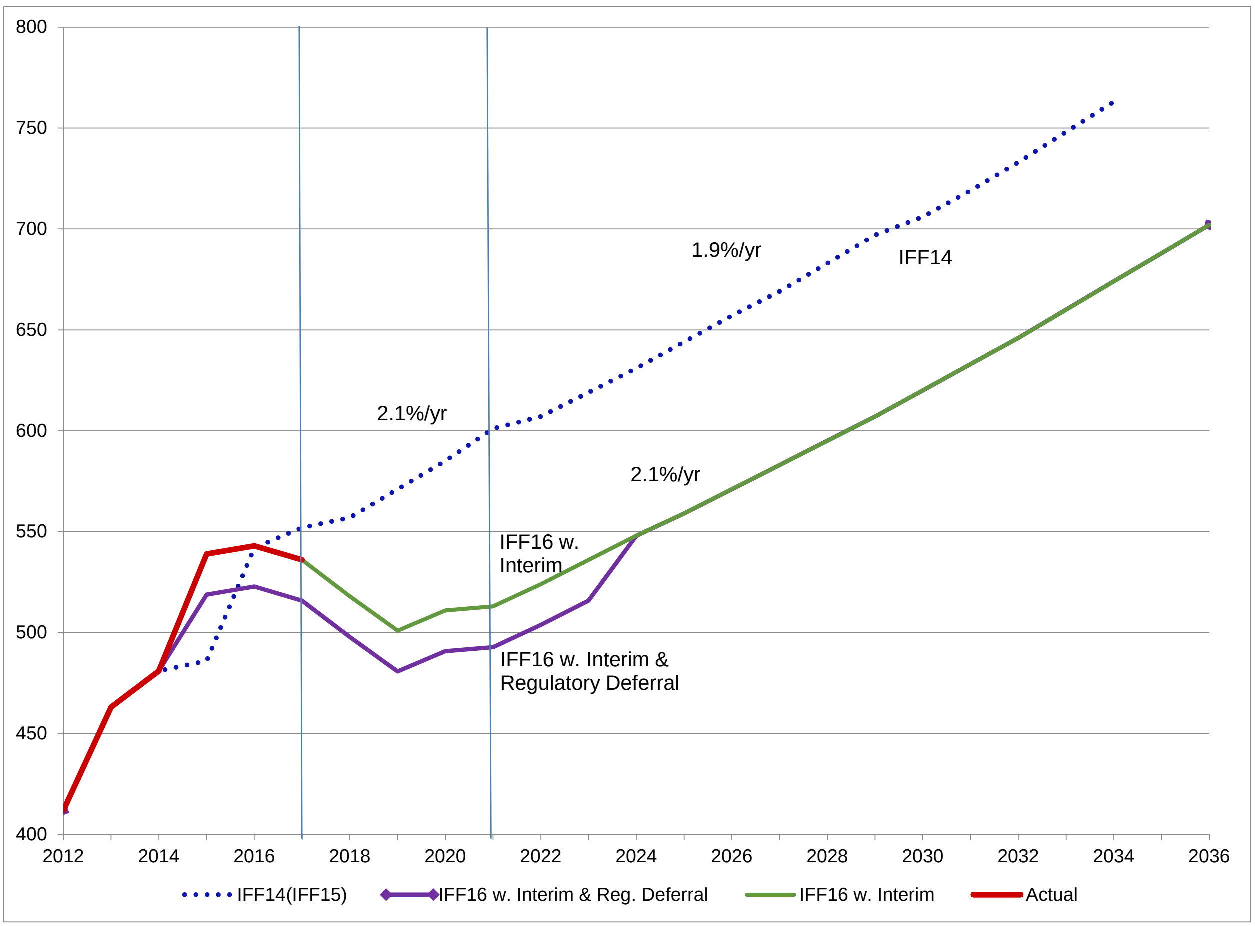
  The practices adopted in MH16 Updated with Interim fail to ensure long-term protection for ratepayers from the charges Hydro made to its accounting on these two topics, despite direction from the PUB to enshrine such protection.
- Section 6.3: Demand Side Management ("DSM") spending assumptions that are above levels consistent with, and appropriate for, managing overall ratepayer impacts, and appear to not be based on Integrated Resource Planning ("IRP") principles.

6.1 OPERATING AND ADMINISTRATION (O&A) COSTS

Hydro's Application sets out forecasts for O&A expenses that, over the 11 years 2016/17 to 2026/27, are $795 million[134] lower than previously projected, in IFF15. Hydro cites various factors contributing to this reduction, including the workforce reduction plan (900 positions)[135] and, to a much lesser degree, procurement savings. However, due to the significant scale of changes having been recently imposed, much of the normal detail filed in support of O&A forecasts is unavailable.[136]

Figure 6-1 below compares IFF16 Updated with Interim to IFF14 (IFF15 was equal to IFF14 for O&A forecast) and with actual results from 2011/12 to 2016/17.

Figure 6-1: Actual and Forecast O&A Comparison IFF14 (IFF15) and IFF16 Updated ($ Millions)[137]



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[134] Tab 3 page 8.
[135] Tab 3, page 10
[136] Tab 6 page 21.
[137] Actuals from PUB-MFR-23, IFF14 - Appendix 3.3 in the 2015/16 GRA, IFF16 w. Interim Appendix 3.8. IFF16 w. Interim adjusting for net movement in the regulatory deferral from 'ineligible overheads' from PUB/MH I-1a-f pages 2 – 5.

As shown in Figure 6-1 above, the scale of reductions targeted by Hydro is clear. The green line (IFF16 Updated with Interim) exhibits a clear savings compared to IFF14. Further, the implementation of the Board-directed Regulatory Deferral to capitalize amounts that are not properly charged to O&A in the year they incur is also shown in the purple line (also showing the time limited benefit from Hydro ending the deferral in 2023/24). Note that following the period of focused reductions, Hydro's current O&A forecast shows average long-term growth resuming at a 2.1% rate, which is slightly higher than IFF14 at 1.9%.

One typical assessment used to consider the revenue requirement is to look at total O&A spending, both prior to and net of capitalization, over time. In Hydro's Application[138] and in response to PUB/MH II-9 Manitoba Hydro does not provide forecast capitalized order activities and capitalized overheads for O&A. In response to COALITION/MH I-110 MH states:

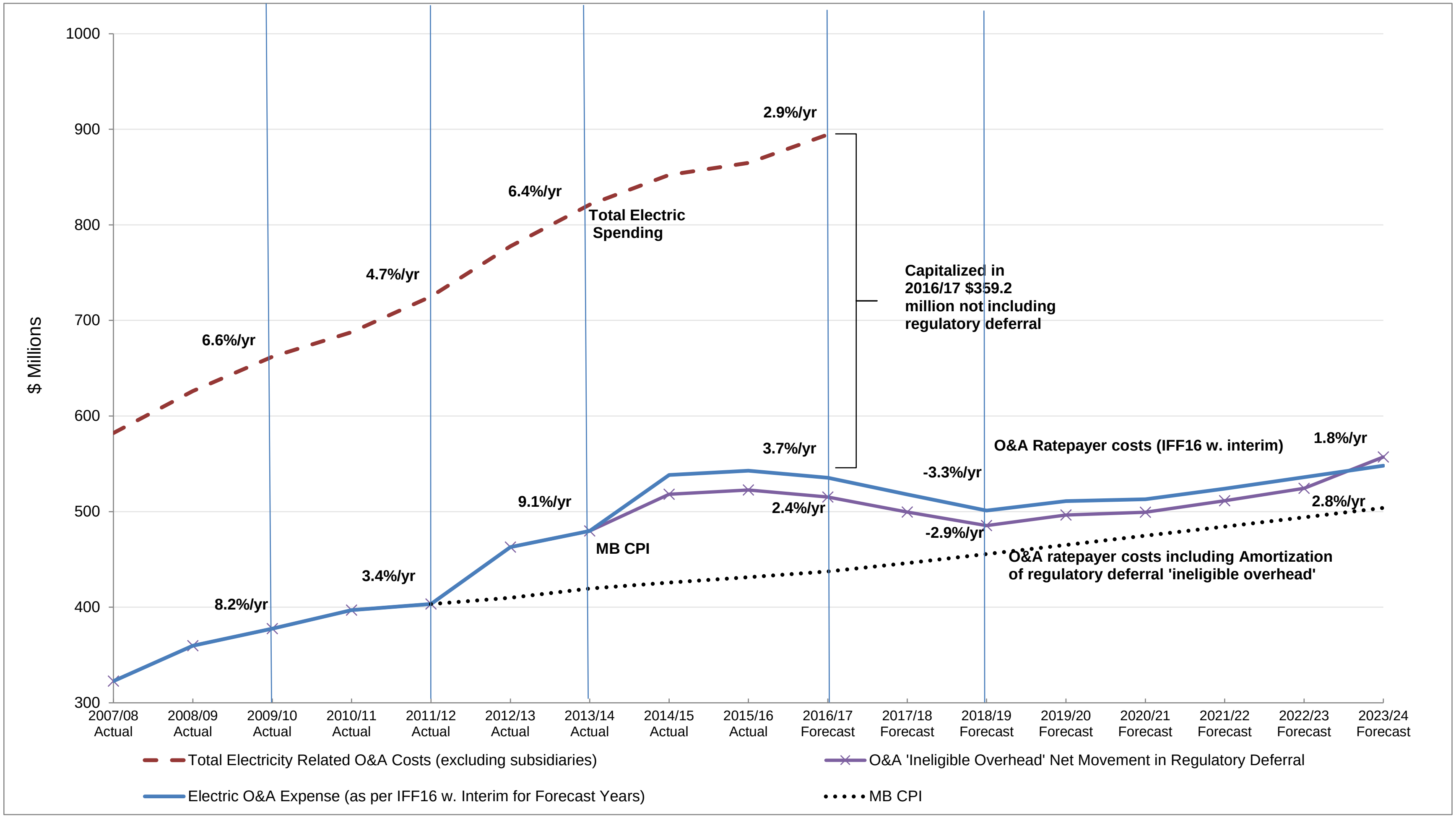
> "The O&A target for 2017/18 was based on the year end projection for 2016/17 actual results, adjusted for known wage settlements (IBEW) and the assumptions associated with senior management reductions and the voluntary departure program. The forecast assumed a reduction of approximately 500 EFTs at the corporate average salary plus benefits. Savings were assumed for a partial year as staff were anticipated to leave throughout the year. In addition, savings of approximately $6 million for supply chain initiatives was incorporated. O&A savings from both workforce reductions and supply chain were assumed to be allocated 96% to electric operations and 4% to gas operations."

As such it is not possible to fully compare total O&A spending in 2017/18 with total O&A spending from previous years (inclusive of capitalized spending) or total forecast savings.

The available information regarding total O&A spending over the longer-term is shown in Figure 6-2 below.

[138] Tab 6, page 22, Figure 6.14 Operating and Administrative Expense Breakdown

Figure 6-2: Actual and Forecast O&A ($ Millions) including impacts of Capitalization and Accounting Changes[139]



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[139]2016/17 Total Electric Spending reduced for Year End Outlook Adjustment of $16.3 million, total Electricity Related Costs less gas operations from Tab 6, page 22 of 55 (revised) June 21, 2017; Electric O&A expense per Appendix 3.8 IFF16 w. Interim; Hydro's O&A excluding accounting changes equal to IFF16 w. Interim O&A less actual OM&A accounting changes provided in COALITION-MFR-4; Net movement in 'deferred ineligible overheads' included in IFF16, then removed in regulatory deferral account (additions less amortization) from PUB/MH I-1a-f pages 2 – 5 of 41; MB CPI from PUB MFR-53 Attachment 1, page 17 weighted to the 2013/14 actual year to approximately accommodate accounting changes.

Figure 6-2 above shows total electric O&A spending (prior to capitalization) as the dashed red line through 2016/17. Similar data is not available for the forecast years. The figure shows the rapid pace of growth that had been occurring since 2007/08 in overall spending.

Looking to the portion of spending that is expensed (as opposed to capitalized), the blue line shows the actuals and forecasts per IFF16, with the purple line shows the amount after the PUB directed additional capitalization, which is recorded as a regulatory deferral.

Manitoba Hydro's cost containment strategy has been to limit growth in O&A costs to a target of 1%.[140] As mentioned previously, it is not possible with the information available to see if this is achieved in the forecast for total O&A (including capitalized costs). Hydro's cost savings strategy includes staff reductions (900 positions primarily in 2017/18 and 2018/19) and supply chain savings initiatives underway since 2014/15 (comprehensive management of staff positions across all Corporate and Operating groups, strategic sourcing opportunities, and negotiating wage settlements). Hydro states these actions result in a reduction to the O&A forecast by approximately $1.35 billion over the 10 year period 2017/18 – 2026/27 (with approximately $515 million of this capitalized and $935 million operational).[141] These figures can not be confirmed in Hydro's financial forecast.

Figure 6-2 also provides a long-term perspective on the O&A cost levels Hydro has experienced, as compared to inflation benchmarked off of the 2011/12 year. In that year, the PUB issued Order 5/12 which indicated a high level of concern regarding Hydro's costs, noting: "The Board, in past Orders, has recommended that MH find ways to control the growth in operating expenses. The Board continues to believe that MH should look internally to find efficiencies and control the growth in operating expenses."[142] Further, the Board specifically flagged that Hydro's staff complement had grown by 900 Equivalent Full Time positions in only 8 years (2004 to 2012) during which no notable changes had occurred to the utility's operations or duties.[143] Order 5/12 followed from Order 116/08 (from 2008), which noted: "Expectations from past recommendations related to OM&A expenses have not been met. The Board expects MH to control OM&A expense levels to assist in meeting its financial targets. Further control of OM&A costs is vital given the planned major capital expansion, and in light of the fact that MH will not meet its debt to equity target over the current forecast period."[144] Comparing the O&A expenses in Figure 6-2 above, it is clear that despite Hydro's cost containment efforts, the utility has not even achieved a level of O&A that is as low as simple inflation since the 2011/12 year. Achieving a level of costs that is benchmarked to 2011/12

[140] Tab 6, page 23 of 55.
[141] Tab 3, page 10 of 22 - $900 million from staff reductions ($700 million operational savings and $200 million related to capital) plus $450 million for supply chain management initiatives (approximately 70% capital and 30% operational) for ten year forecast period to 2026/27.
[142] Order 5/12 page 100
[143] Order 5/12 page 92.
[144] Order 116/08 page 107-108.

(when the Board was indicating O&A costs were already too high) plus the full CPI inflation since that time would require additional future cost control beyond that projected by Hydro to date. In short, following a period of excessive cost build up since before 2008, Hydro's current cost containment efforts, while notable, serves only to take out a portion of the cost pressures that have arisen since 2011/12, and makes no progress on addressing what were already in 2011/12 recognized as a high and poorly benchmarked O&A expense level.[145]

6.2 REGULATORY DEFERRAL ACCOUNTS

Hydro's use of regulatory deferral accounting is a new development, made possible by the adoption of IFRS 14 - Regulatory Deferral Accounts. Prior to this standard being adopted by Hydro, the Board could readily elect to not collect, or to defer, individual items when setting rates (pursuant to the legislative framework based on rates only reflecting a level that is just and reasonable), but Hydro would not have had tools to match this timing outcome when preparing its IFRS financial statements. For example, the Board may set rates based on an expense being properly recorded in a given future year, but Hydro may have been required by IFRS to reflect the expense, for financial statements purposes, in an earlier year. IFRS 14 helps address this issue, but does not resolve it entirely.

In charging prices for power, Hydro can (and must) implement the Board directives in full. Where this requires differences in the timing for recognition of costs or revenues that would otherwise be the case under IFRS, and where permitted by IFRS 14, Hydro can now more closely match its IFRS statements to the regulatory statements as directed by the PUB. The purpose is not to impose reverse constraints on the PUB (e.g., there ought be no suggestion the PUB cannot fulfill the role provided by the *Public Utilities Act*, because IFRS 14 does not allow the outcome) but rather to help manage the presentation of Hydro's IFRS financial statements for readers who are not otherwise aware of the assets and liabilities created by the Board's decisions.

In establishing the new IFRS deferral accounts, Hydro has calculated its MH16 forecasts on the basis of inappropriate calculations within the regulatory deferral accounts, related to capitalization of overheads, and to deferring the adverse impacts of the ELG depreciation procedure.

6.2.1 Capitalization of Overheads

In Order 43/13[146] from 2013, the Board noted that Hydro had made changes to its capitalization policies between 2008 and 2012 which led to far more of Hydro's costs being charged to the current period when

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[145] A portion of the cost increases shown on the expensed portion (blue line) since 2012 are for accounting changes that adversely affect current day ratepayers. Cost containment efforts to overcome this pressure on ratepayers would help achieve the benchmark "2011/12 plus inflation" line shown.
[146] Order 43/13, pages 13-14

the cost was incurred (and therefore built into near-term power rates) and far less to the capital project (where the cost would be deferred over the life of the assets being built). At that time (2013/14), the extra costs being expensed in the current period income statement rather than capitalized totaled $57.6 million per year, as compared to past practice. Hydro also identified that a further $36 million of costs that would have previously been capitalized would, going forward from 2015/16, would instead be included in current year costs, to total $93 million/year. This was a significant concern, as $93 million per year is as large as the rate increases in an entire GRA,[147] and the driver was simply a policy or accounting change and not any underlying cost pressures in Hydro's operations. Nonetheless, the Board accepted the $93 million/year impact in Order 43/13 but indicated Hydro should not make any further accounting changes for rate-setting purposes[148].

Instead, with the filing of the 2014/15 & 2015/16 GRA, Hydro indicated it now planned to take into current periods charges totaling $118 million/year that had previously been capitalized.[149] The Board concluded that with respect to costs previously capitalized that would no longer be capitalized "the quantum of those costs has increased materially in Manitoba Hydro's IFRS Status Update, by $20 million per year"[150] and concluded that the Board would require a portion of the $118 million in costs "continue to be capitalized as per existing practices."[151]

For the April 1, 2016 Interim Rates Application indicated Hydro did not implement the above noted direction. The Board sought financial scenarios that did implement the directive, by capitalizing the $20 million/year of overhead expense and amortizing it over 30 years.[152] In their decision on the matter, the Board noted: "The actual OM&A expenditures recorded in IFF15 do not accurately reflect the Board's Directive in Order 73/15 for Manitoba Hydro to continue to capitalize $20 million in overhead costs rather than expense that amount when Manitoba Hydro converted to IFRS."

[147] A 3.95% increase on a domestic revenue base in 2018/19 of $1.615 billion is only $64 million/year.
[148] Order 43/13. April 26, 2013, page 14 & 15.
[149] Order 73/15 page 32.
[150] Order 73/15, page 35
[151] Order 73/15, page 36.
[152] PUB Financial Information MFR 1 (Attachment 28) from the 2016/17 Supplemental Filing.

The current GRA sets out how Hydro has now implemented this direction, in comparison to the approach that was provided in the April 1, 2016 Interim Rates Application (in response to PUB setting Minimum Filing Requirements):[153]

1) In the current GRA, $20 million in OM&A expense will be "deferred" to a regulatory deferral account for each year until 2022/23. After this, no further deferral will occur. In the previous interim filing proceeding, it was assumed the $20 million/year deferral would operate indefinitely.

2) The balance in the regulatory deferral will begin amortizing in 2017/18.[154] The materials from the previous interim filing proceeding did not specify when amortization was assumed to be initiated.

3) The GRA amortization is calculated based on a 20 year amortization period. In the previous interim filing, a 30 year period was used, which closely matches the Average Service Life for the purposes of depreciation true-up amortization, which is 34 years.[155]

Reviewing the above material, it is important to ensure clarity regarding the purpose of the overhead deferral. The reason the deferral is required is that IFRS focuses on different priorities than rate setting. Consider the case of certain overhead functions, such as establishing "Safety Manuals and Standards"[156] or fleet management:

- **IFRS:** In the case of IFRS, the purpose of financial statements is to record the financial position of a Corporation, including its exposure to cost items that continue to be incurred whether capital projects continue or not. Items that exist in the Corporation's cost structure, such as safety manuals and standards, are too far removed from the capital project to be capitalized. Further, the reader of the financial statements is to be aware that these costs are incurred in the year and, absent any capital investment occurring, would continue to be part of the Corporations expenditures. For these reasons, IFRS does not allow such costs to be capitalized. Similar comments apply to topics such as overall fleet management.[157]

- **Regulatory:** In the case of regulatory rate setting, the longstanding principle that underlies whether a cost is recoverable from ratepayers in a given year is whether it is "used and useful" in that year. If Hydro maintains a large fleet management department, or a safety manuals and standards department whose tasks relate 50% to capital programs and 50% to operating activities, then half of the costs of those departments arising in the current year are not used and useful to provide service in the current year – they are used and useful to provide service to future ratepayers

[153] MIPUG/MFR-5, page 1.
[154] PUB/MH I-1a-f page 2
[155] PUB Financial Information MFR 1 (Attachment 28) from the 2016/17 Supplemental Filing.
[156] See MIPUG/MH I-7a from the 2015 GRA where this example is used.
[157] Individual vehicle use on a capital project can be capitalized, but the general operation and management of a fleet department cannot.

when the assets under construction are put into service. For this reason, regardless as to the IFRS accounting methods to be applied, it is appropriate for the regulator to expect that 50% of the noted departments are "capitalized" and brought into rates in a manner that matches the projects which they supported. Accounting standards previously permitted this approach, under a "full cost accounting" philosophy,[158] but no longer. If the overhead amounts cannot be tracked project by project (and depreciated commensurate with each project, as would have occurred under the pre-IFRS full cost accounting regime within Hydro), then at minimum the amounts should be capitalized to a deferral account and amortized over a composite remaining life that reasonably represents the assets that were put into service in that year, or alternatively a composite representing Hydro's overall average asset life.

Given the above framework, the appropriate implementation of the Board's directive is as follows:

- The specified annual amount ($20 million) should be capitalized or deferred in each future year, without a termination date where the $20 million/year stops being capitalized.
- The amount should be amortized starting in the first year in a manner that reasonably matches what would have occurred had it remained part of Hydro's capitalization mechanics – amortize to income as part of depreciation expense, at a rate representative of the projects to which it is tied, or alternatively a rate which reasonably represents a blended of Hydro's overall asset lives (such as 34 years).

The outcome will yield a net cost to ratepayer that is comparable to what would have occurred had the amounts remained treated as overheads (precisely as intended by the Board's conclusion that Hydro should "continue to be capitalized as per existing practices").[159]

With respect to Hydro's concern that this approach could lead to "significant regulatory deferral account balances" that "may result in the burden of recovery of today's IFRS impacts being pushed out to future ratepayers,"[160] this is precisely the point of the deferral. As noted above, the regulatory conclusion is that $20 million of costs linked to such notional functions as management of the overall fleet pool, or safety manuals, are in fact not a current year used and useful expense, but an expense that is used and useful for its role in enabling Keeyask, or Bipole III, or Gillam Redevelopment, and as such these costs should be recovered from ratepayers who receive service from these assets, exactly as occurs now for depreciation expense and will continue to be occur for all direct capital costs. The precise purpose is to alter the IFRS

[158] For example see Board Order 43/13, page 13.
[159] Order 73/15, page 36.
[160] MIPUG/MH II-10a-c, page 2

impacts so as to record costs to match the related useful service time periods, consistent with longstanding regulatory rate making principles.

Further, it is not accurate for Hydro to conclude that "extended amortization periods linked to the lives of assets for regulatory deferral accounts" is not to be favored "as excessively large deferral balances pass the risk of recovery to future generations of rate payers."[161] Given that the intent is to recognize these costs to be part and parcel of capital developments, the $20 million/year represents spending that is as much a part of, for example, Keeyask, as is any given turbine or gate or valve a part of the project. In short, the Board's approach is not to pass risk of recovery to the future, it is to prevent the future from inappropriately ladening the present with costs that are as integral to future service as all other capital expenditures.

In short, the current GRA fails to fully implement the Board's directive and undervalues the importance of this measure by artificially terminating the deferral where it is not merited, and using an amortization period that is too short. Hydro should be directed to adjust these factors in MH16, and in all go forward regulatory deferral calculations. Not only will this ensure proper matching, but this will also lead to an appropriately enhanced net income and retained earnings levels over the course of MH16 compared to what is now shown in PUB/MH I-34 Attachment 2, and will increase Hydro's ability to achieve a 75:25 debt ratio. The adjustment will not directly improve nor harm Hydro's cash flows, as deferral and amortization is a non-cash adjustment.

6.2.2 The Implementation of Equal Life Group Depreciation

In the current filing, Hydro has provided proposals for implementing the Board's findings in respect of Equal Life Group (ELG) depreciation from Order 73/15. That Order set out two key directions:

1) The Board required Hydro to provide forward-looking and IFRS compliant depreciation studies under the ELG procedure, and also under the alternative Average Service Life (ASL) procedure which Hydro has used prior to IFRS. This directive was first provided to Hydro in Order 43/13 (Directives 8 and 9) and Hydro has yet to comply.
2) Pending the full compliance with the above directive (allowing a proper and fully informed comparison of the two procedures), the Board ordered Manitoba Hydro, for purposes of rate-setting, "to continue to determine Depreciation Expense based on its existing ASL methodology."[162]

[161] MIPUG/MH II-10a-c, page 2
[162] Order 73/15, page 45

In the current GRA, Hydro notes that it has not undertaken the directed studies noted above from Order 43/13[163] (2013). As a result, Hydro continues to operate under the second bullet noted above – that is, using an existing ASL methodology for rate setting.

The specifics of the approach proposed by Hydro changed from the original filing to the July update[164]. Under the latest proposal, Hydro plans to:

- set rates in 2017/18 and 2018/19 based on the ASL procedure;
- record depreciation expense for its IFRS financial statements using the more aggressive and higher cost ELG procedure;
- defer to the Regulatory Deferral Account the difference between the two methods each year;
- Continue to this same deferral approach annually until 2022/23 and terminate the approach at that time (when, given no further deferral, the ELG approach will by default be used for rate setting); and
- Amortize the deferral account balance, starting 2019/20[165], over 20 years.[166]

There is an obvious basis for concern that Hydro has not complied with the Board's clear directions in Order 43/13, as repeated in Order 73/15.

Outside of this concern, however, the approach Hydro has adopted for this hearing leads to an appropriate net outcome for the test years. Specifically, the outcome for rates in 2017/18 and 2018/19 is that depreciation expense will be based on the longstanding and well-accepted ASL procedure. This procedure recovers all costs of Hydro's capital assets over the life of the assets, in a manner that sees widespread use among regulated utilities.

The acute issue raised in Hydro's materials is a concept that Hydro plans to defer and amortize, by way of a regulatory deferral account, the extra depreciation expense that Hydro elects to record in its IFRS financial statements as compared to its rate setting ASL approach.

The net effect of Hydro's proposed approach is set out in Table 6-1 below.

[163] Tab 10 page 8
[164] Supplement to Tab 3, page 14
[165] PUB/MH I-1a page 2 of 41
[166] MIPUG/MH I-7a-f, page 9

Table 6-1: IFF16 Forecast Depreciation Expense (ELG vs. ASL)[167]

	Regulatory Deferral - Change in Depreciation Method ($ Millions)	Actual 2015	Actual 2016	Actual 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	Opening Balance	-	28	59	91	125	164	201	236	272	315	298	281	263
2	Additions	-28	-31	-31	-34	-40	-43	-45	-48	-56	0	0	0	0
3	Amortization	0	0	0	0	0	6	9	12	14	16	18	18	18
4	Closing Balance	28	59	91	125	164	201	236	272	315	298	281	263	245
5	Net Movement	-28	-31	-31	-34	-40	-36	-35	-36	-42	16	18	18	18
6	IFF16 Depreciation Expense (i.e. ELG)	352	367	375	396	471	515	555	597	689	714	726	739	752
7	**Depreciation IFF16 & Net Movement**	**324**	**336**	**344**	**362**	**431**	**479**	**520**	**561**	**647**	**730**	**744**	**757**	**770**
8	*Derived 'ASL' Depreciation Expense***	*324*	*336*	*344*	*362*	*431*	*472*	*510*	*549*	*633*	*655*	*666*	*678*	*691*

Reviewing Table 6-1 gives rise to the following notable concerns:

1) Hydro has achieved a net result from 2015/16 to 2018/19 that is consistent with the intended purposes – that ratepayers pay a depreciation expense (as recorded in row 7 of the Table) that matches the derived ASL expense (row 8 of the Table), consistent with longstanding regulatory practice. This is a positive outcome. However, after 2018/19, the values diverge.
2) Starting in 2019/20, the depreciation expense recorded on the IFF (and therefore underpinning net income calculations and rates) begins to depart from the intended ASL approach, due to Hydro amortizing the balance that has been deferred.
3) Following 2022/23, the expense completely departs from the ASL linkage and becomes fully based on ELG, with the added expense of amortizing the deferral account.

The issue above is material, in that by 2022/23 the difference between the ASL method that the Board requires Hydro to use, and the ELG method that Hydro is adopting for IFRS purposes, is $56 million in that one year alone,[168] plus Hydro would be amortizing a further $14 million from the deferral account. By 2023/24 both these adverse items will be include in Revenue Requirement under Hydro's proposal, contrary to the principle that rates should be set based on the ASL procedure.

The issue is also of concern, in that the Board's directive was to continue to use the existing ASL methodology for setting rates, until such time as the Board could review full information on the impacts of moving to a higher cost method (ELG). Yet the above proposed approach implements a notably higher-

[167] Depreciation Expense from IFF16, Regulatory Deferral Calculations from PUB/MH I-1a for 'Change in Depreciation Method' row. ** Derived 'ASL' depreciation expense calculated as IFF16 Depreciation Expense (ELG) row 6 less 'additions' row 2 from regulatory deferral from 2015 to 2023. For 2024 – 2027 calculated as ELG row less difference in net movement as provided in response to PUB/MH I-1d (indefinite amortization of ELG/ASL difference) and in Appendix 3.8 MH16 update with Interim then adding back in row 3 amortization. This approach matches the ASL amount provided in response to PUB/MH II-2c for CGAAP ASL in 2023/24 ($655.8 million).

[168] For context, in that year the full 3.95% increase shown in PUB/MH I-34 Attachment 2 is only worth approximately $73 million (the difference between $392 million in that year in added revenue from rate increases, versus $319 million in the previous year).

cost method – ASL plus amortization for 2019/20 to 2022/23, and ELG plus amortization for 2023/24 and beyond. This is proposed notwithstanding Hydro has still failed to comply with the required information, and has not provided a full assessment of the impact and benefit (if any) to ratepayers of the move. Over the 20 year financial forecast period, the difference between ELG and ASL cumulatively adds $846 million to depreciation costs in MH16 update with interim.[169] Additionally, Hydro's proposed regulatory deferral account annual amortization charge for this difference adds another $272 million to costs over the 20 year financial forecast[170].

There is no basis in the record for Hydro to simply assume that it will be permitted to implement ELG for rate setting, whether at 2023/24 or any other date, and the IFF should reflect this reality to ensure accuracy.

Even if this assumption in the IFF were adjusted to ensure the added cost of ELG in any given year is not directly included in rates, this would still not address the issue of the proposed amortization of the difference between ASL and ELG. This amortization is proposed at 20 years, which means each year the deferral account will grow by a particular balance, and amortize a portion, leading to slow increases in the balance year by year until deferrals grow to match annual amortization. By the time this occurs (year 20 under a steady state assumption regarding asset mix) the effect will be that Hydro has implemented the cost profile of ELG, simply via a backdoor mechanism. This outcome is also shown in the response to MIPUG/MH II-13a-b, which shows that once the amortization component is added to the ASL depreciation expense (in this case of a hydraulic asset), the sum is very close to the ELG cost within approximately 20 years. While Hydro notes in response to MIPUG/MH II-15a-b that "It is not Manitoba Hydro's contention that the PUB must ultimately accept the ELG procedure for determining depreciation expense for ratemaking purposes"[171], the end result of an amortization-based proposal is precisely that – a forced (and slow-motion) acceptance of ELG costs being included in rates.

[169] The difference between ASL and ELG is estimated based on net movement from PUB/MH I-1d, which has an indefinite amortization period for the ASL/ELG deferral, less net movement in MH16 update with Interim (Appendix 3.8), less the amortization amount (estimated at $18 million from 2027/28 to 2035/36). Summing over the 20 year period this difference between ELG and ASL is $846 million.
[170] The sum of regulatory deferral amortization for 'Change in Depreciation Method' from 2020 to 2027 in PUB/MH I-1b, with $18 million used as estimate for years 2027/28 to 2035/36 based on known 20 year term.
[171] MIPUG/MH II-15a-b, page 1

There are three ways avoid this outcome:

1) Implement ASL on an IFRS compliant basis – however, it is understood that consideration of this approach, despite being the subject of an outstanding PUB directive, is outside the scope for this proceeding per Order 70/17.[172]

2) Not include any effects of ELG in rates in any year. This approach is consistent with the PUB ensuring, consistent with many other rate regulators, that customers are not burdened with the adverse effects of the ELG procedure. This approach is also consistent with the PUB's letter to Hydro of April 4, 2016[173], which noted that the Board considered the appropriate approach to be as set out in the materials to the 2016/17 Interim Rate Application, Attachment 46, Scenario 2, which was designed to ensure "no impact on rates for rate-setting purposes of the amortization of these deferral accounts."[174]

3) Operate a deferral account, but with no amortization of the balance, allowing the net difference between ASL and ELG resolve over time. This approach would be based on Hydro's explicit testimony that ELG is not more expensive over time, and that as assets age the ASL approach will become more costly than ELG and allow for a measured drawdown of the balance of the deferral. This perspective on ELG as higher cost than ASL for some period, then lower costs after a 'crossover' point was highlighted by Hydro in each of the last two GRAs when advocating in favour of the ELG approach[175], and reiterated by the PUB in Order 73/15:

> Under either ASL or ELG, Manitoba Hydro is eventually made whole, since by the time an asset is decommissioned, the entire capital cost has been recovered by Manitoba Hydro from ratepayers.[176]

The basic premise behind this approach is to permit Hydro to be "made whole" through future ELG savings that it purports will occur, rather than added costs to ratepayers prior to these benefits being reached. This approach is mathematically equivalent to the approach set out by Hydro in response to PUB/MH I-1d (as noted in MIPUG/MH II-16b).

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[172] "The Board-approved depreciation methodology (the issue of Average Service Life versus Equal Life Group) is not an issue for this Hearing. However, the proposed recovery of the financial difference in a deferral account is within scope." Per Order 70/17

[173] Appendix 10.9

[174] Attachment 28, Financial Information MFR-1 from the 2016/17 Interim Rate Application

[175] For example, Page 3597 of the transcript from the 2015 GRA, in which Mr. Larry Kennedy, Hydro's witness, testified as follows "…if you take an account from Manitoba Hydro, any account, and you were to apply the ELG procedure to that account you would get a different answer than you would as compared to using the ASL. Overall, you -- both methods will recover all the original cost, but at any point in time the depreciation rates would be different."

[176] Order 73/15 pages 45 - 46

The above options are expected to lead to similar net outcomes with respect to rate setting, consistent with an ASL procedure, which is the ultimate purpose. Precise implementation in Hydro's financial statements are a matter for Hydro's management and its auditor to resolve. This is also reflective of the Board's jurisdiction with respect to setting just and reasonable rates, and recognizing that "…the Board clarifies that its mandate with respect to prescribing accounting methods is limited to determining the appropriate accounting for rate-setting purposes, but not for financial reporting purposes. While in the Board view, it would be preferable for Manitoba Hydro's financial statements to be consistent with the Board-approved rate-setting methodology, the Board cannot provide the requested guidance as to how Manitoba Hydro should prepare its financial statements for financial reporting purposes."[177]

The impact of the above approach is material to rates and Hydro's finances. While no 3.95%/year rate increase scenario was run, PUB/MH I-1(d), as compared to Appendix 3.8 (both based on 7.9%/year increases), shows an increased retained earnings by 2026/27 of over $340 million[178]. This benefit should be included in IFF for rate-setting purposes.

6.3 DSM SPENDING ASSUMPTIONS AND INTEGRATED RESOURCE PLANNING

Manitoba Hydro's application and materials filed in response to Information Requests highlight a continuing failure to implement the Board's recommendations in respect of Integrated Resource Planning, to the long-term detriment of ratepayers.

6.3.1 Background

In the NFAT proceeding, the PUB final report and recommendations highlighted that Hydro had failed to use what the Board considered to be a proper Integrated Resource Planning ("IRP") approach, and in doing so failed to treat Demand Side Management (PowerSmart) on an equal footing with other resources. Specifically, the PUB Report noted.[179]

> By failing to offer an analysis of conservation measures as a stand-alone energy resource competitive with other generation resources, Manitoba Hydro presented an analysis of conservation measures that was neither complete, accurate, thorough, reasonable nor sound.

[177] Appendix 10.9, page 2
[178] $6.909 billion (PUB/MH I-a-f) versus $6.564 billion (Appendix 3.8)
[179] Public Utilities Board Report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan, June 2014, page 33

The panel provided recommendations as follows.[180]

> The Panel recommends that integrated resource planning become a cornerstone of a new clean energy strategy for the Province of Manitoba.

In discussing Hydro's failure to properly consider conservation and DSM, the panel noted.[181]

> The Panel heard evidence that the best practices for integrated resource planning involve placing every conceivable resource option on an equal footing.

And further:[182]

> In its resource planning, Manitoba Hydro added DSM to each alternative plan it examined. By doing this, Manitoba Hydro effectively screened out DSM as an independent resource to be evaluated against other generation resources.

6.3.2 Current Application

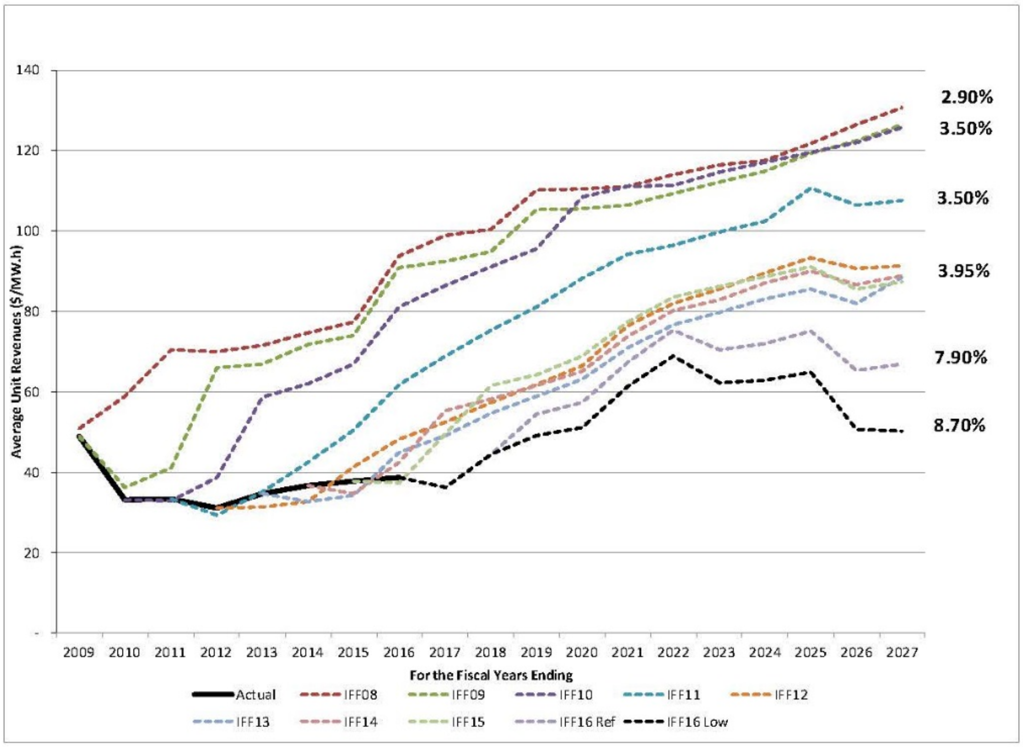
At the present time, the context for Integrated Resource Planning is significantly changed compared to the NFAT context in the following ways:

- **No new resources required:** Manitoba Hydro does not require spending on new resource development. Keeyask and Bipole III are proceeding towards completion along with the 500 kV international transmission line, and no other assets are proposed to be required to meet domestic bulk power needs in the near-term planning horizon. Under current expectations, no new resources are required until 2040.
- **Financial concerns over spending:** Manitoba Hydro has heightened its presentation of financial concerns, focused in a significant way on total debt levels, cash flow for Capital Expenditures (which includes DSM) and improving progress against financial targets. DSM spending in the near term is one factor adding stresses to this financial situation.
- **Export prices low:** Export pricing is described as having been significantly reduced (20% below MH15 levels)[183] and risk scenarios presented by Hydro suggest continuation of low export prices must be considered.[184] In particular, MH16 not only lowered export prices compared to IFF15, but

[180] Public Utilities Board Report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan, June 2014, Page 36
[181] Public Utilities Board Report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan, June 2014, Page 91
[182] Public Utilities Board Report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan, June 2014, Page 92
[183] Tab 2, page 5
[184] Tab 2, pages 13 to 24

sustains the low export prices much further into the future than any recent price adjustment since the NFAT, as shown in the reproduced figure below. In particular, the 4 years of IFFs shown as targeted towards 3.95% rate increases on the right hand side of the figure (IFF12, 13, 14 and 15) show a confluence in price forecasts after the 2022-2027 period, which has now been significantly reduced under IFF16 and significantly further reduced in MH16 Update, which is not included in Figure 6.3 below):

Figure 6-3: Progression of Forecast Average Unit Revenues Compared to Actual Averages Prices[185]



As a result of lower sustained export prices, the economics of DSM spending (particularly in the next 5-10 years) are much less supported by replacement value from exporting the power that was conserved in Manitoba.

- **Natural Conservation and Rapid Market Advancement:** The market for conservation devices and activities is well accepted to be maturing and accelerating in many areas, leading to a reasonable expectation of significant conservation activities and uptake occurring outside of a need for utility spending. Energy conserving devices are a normal part of many reasonable investment decisions made by residences and firms. For this reason, there is the potential for significant concerns that the reported conservation achievements are not in fact the result of Hydro's DSM

[185] Tab 3, Figure 3.7, page 15 of 22

program and investment but rather conservation that would occur even outside of Hydro's DSM activities. It is reasonable to conclude that absent Hydro's DSM spending much of the same conservation achievements would be seen over the long-term. To use one visible example, Hydro's measured DSM achievement show that Hydro plans to stop spending on Residential LED lighting incentives by 2018/19;[186] however, Hydro still claims that the Manitoba marketplace in 2030/31 (12 years after the end of the program) will be seeing 13.5 GW.h of savings as a result of these earlier efforts,[187] which is due to devices expected to be in use at that time which would not have otherwise been upgraded to the LED standard absent Hydro's spending in the period prior to 2018. This does not appear to be a reasonable expectation. While this is only one example, a significant component of Hydro's DSM program reported benefits is in the area of lighting (residential LED, streetlight, commercial) totaling almost 40% of Hydro's reported Energy Efficiency achievements by 2030.[188]

- **Near-term Environmental Benefits:** Changes in the US and Saskatchewan utility supply mix now suggest that there is a much lower likelihood that exported power from Manitoba would serve to offset coal generation, which is the highest environmental value for exported power.

Despite the above facts, Hydro has included in its financial forecasts significant assumed spending on DSM activities, of over $751 million from 2017/18 to 2026/27.[189] This has the effect of both increasing costs (to fund the programs) and decreasing revenues (as lost sales domestically are not made up from the low-priced export market).

Focusing on the above mix of conditions, it is clear that challenges have arisen since the NFAT proceeding related to the justification for Hydro's DSM spending particularly on energy efficiency programs. As a result of this clear pressure on Hydro's finances, BCG completed a review of alternative approaches to DSM spending,[190] highlighting the following:

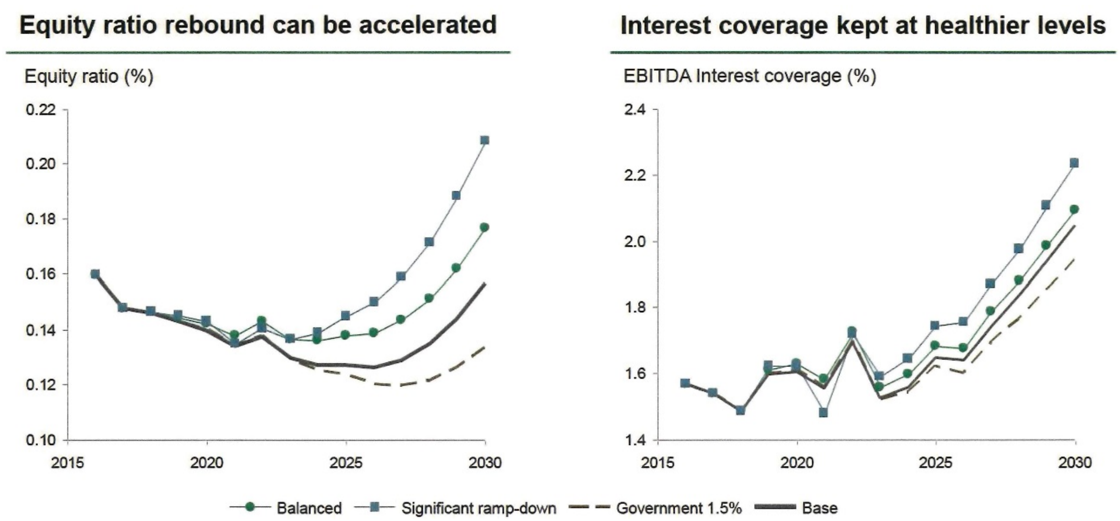
- Status quo DSM spending (per IFF15) required $1.175 billion in investment to 2030. Credible options existed to spend $2.266 billion (to achieve the 1.5% per year target earlier recommended by the PUB) or as low as $350 million (to ramp-down spending to reflect updated conditions).

[186] Appendix 7.2, page Appendix A.2
[187] Appendix 7.2, page Appendix A.2
[188] The 3 LED programs total 603 GW.h out of a total 1,539 GW.h. (This was later updated to some degree in PUB-MFR-61 Updated but it does not appear the year-by-year program savings and spending has been made available for the updated plan).
[189] Tab 5 page 28. This DSM plan was later updated in PUB MFR-61 (a slight reduction) but the full 10 year spending plan does not appear to have been updated.
[190] PUB/MFR-72 pdf pages 215-223 and 279-280

- DSM spending alone had the potential to swing the equity ratio down (i.e., worse off, requiring higher rates) by up to 2-3 percentage point from the IFF15 levels, or up (i.e., better off, requiring lower rates) by up to 5 percentage points by 2030/31. In the context of the 2030/31 balance sheet, this is likely in a range exceeding $1.9 billion to $2.2 billion.[191]

The BCG conclusions regarding impacts of DSM spending on equity ratio are shown in Figure 6-4 below:

Figure 6-4: DSM Adjustment Impact on Financial Ratios[192]



As shown in Figure 6-4 above (from information used elsewhere in the presentation the figures above appear to be based on IFF15), the pursuit of varying DSM scenarios have material effects ranging from the most adverse (Government 1.5%) to the most beneficial (Significant Ramp-Down). Note that Hydro's "base" and "balanced" plans target less savings, and have less adverse impacts, than the full Government 1.5% scenario. Hydro continues to use DSM scenarios for the GRA that have substantial savings, but do not fully achieve the 1.5% per year level[193].

This same concept and calculation range is further provided in response to PUB MFR-77, as shown in the following Figure 6-5.

[191] The total denominator in the debt:equity calculation by 2030 is on the order of $27.6 billion per PUB/MFR-17 Updated. A swing of up to 7-8 percentage points in retained earnings would total $1.9 to $2.2 billion in revised numerator for the retained earnings value (increased equity, reduced debt).

[192] PUB-MFR-72 Attachment, Boston Consulting Group presentation August 9, 2016, pdf page 280 of 615

[193] Appendix 7.2 page vi

Figure 6-5: Incremental Effect on Retained Earnings from Differing Levels of DSM Spending and Energy Savings[194]

		Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)		
	MH16	MFR77i	MFR77ii	MFR77iii
Fiscal Yr Ending	100% of proposed DSM investment 100% of expected savings	50% of proposed DSM investment 50% of expected savings	100% of proposed DSM investment 50% of expected savings	0% of proposed DSM investment 0% of expected savings
2019	3 083	4	4	7
2020	3 427	25	18	39
2021	3 921	64	42	123
2022	4 594	124	82	241
2023	5 094	196	125	385
2024	5 466	275	171	548
2025	5 898	363	222	731
2026	6 265	460	277	930
2027	6 705	572	340	1 157
2028	7 193	699	411	1 415
2029	7 759	836	486	1 694
2030	8 411	983	570	1 989
2031	9 138	1 150	667	2 316
2032	9 979	1 326	770	2 671
2033	10 929	1 506	876	3 035
2034	12 002	1 689	976	3 416
2035	13 200	1 879	1 081	3 803
2036	14 470	2 057	1 174	4 203

As shown in Figure 6-5 above, MH16 baseline shows achievement of $9.138 billion in retained earnings by 2030/31. This retained earnings could be enhanced by $1,150 million (column MFR771i) if DSM programming costs are cut 50% and DSM energy savings are cut 50% (note that this is done as an arbitrary 50% cut, rather than focusing on cutting the least cost-effective programs, for example). The final column expands on this to show that a complete reduction in DSM spending and no new savings would increase retained earnings $2.316 billion (column MFR77iii). Note however that it is impractical to consider a full 100% cut as there are specific DSM programs that are required for identified regional and market participation benefits,[195] and as required by policy.[196]

Of particular interest is the middle column MFR77ii. This column shows the effects of still spending the full DSM budgets as included in MH16, but only achieving 50% of the targeted savings. Should such a situation occur, Hydro's balance sheet (and hence ratepayers) would in fact be better off ($667 million in retained

[194] PUB MFR-77, Figure 1, Manitoba Hydro 2017/18 & 2018/19 GRA
[195] E.g., the Curtailable Service Program
[196] E.g., the Affordable Energy Fund

earnings) by the failure of the program to deliver conservation. Rate levels (and Hydro's financial condition and risk) would in fact be better off if Hydro spent the DSM program dollars on initiatives that failed to achieve conservation rather than those that do achieve conservation than if the programs had been successful and the net savings achieved. This is an important analytical result suggesting the spending level as proposed does not appropriately link with the interests of ratepayers.

In short, the above scenario highlights that DSM spending under today's context is not achieving the basic premise that is normally cited for exporting utilities, as acknowledged by the PUB in the NFAT report:[197]

> "In jurisdictions that export surplus energy and capacity, DSM savings may mitigate the rate increases associated with the cost of DSM measures. This mitigating effect comes from the ability of DSM measures to free up more energy and capacity for export, and thus increase revenues from export sales. If export prices are equal to or greater than the utility's costs of the DSM measures, these costs could be recovered from export revenues and ratepayers might not see a rate increase at all."

The PUB further cited[198]:

> "In its updated analysis of ratepayer costs for the Panel, Morrison Park found that DSM Level 2 had a "powerful effect" on ratepayer costs in that it brought ratepayer costs down. They noted that DSM can not only help to reduce the electricity bills of ratepayers who take advantage of the programs, but also reduce Manitoba domestic load, and free up more capacity for export."

Such conditions in support of a favourable DSM economic profile do not exist today.

More critically, the value proposition of DSM is tied not only to the rate impact versus the status quo, but also the rate impacts versus a full alternative scenario. On a status quo basis, Hydro's finances are negatively affected by DSM spending and by lost revenue, but benefitted by gained export revenue. Often DSM is framed as a short-term net cost for a long-term net benefit as the export market prices grow larger with time. However, the above analysis shows that on even long-term horizons, DSM is a net loss activity, and that it does not turn around with time (e.g. the results in 2036 are not better than the results in 2035).

On the basis of a full alternative scenario, it is necessary to assess whether the result in Figure 6-5 belie the costs that Hydro would have to incur to replace the power that it otherwise planned to come from DSM.

[197] Public Utilities Board Report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan, June 2014, page 84
[198] Public Utilities Board Report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan, June 2014, page 85

This is the "resource deferral" value for DSM that is one component of the DSM value proposition. The general notion would be that DSM may be more costly than not doing DSM, but that without the DSM, one would need to invest in a new resource like Conawapa, which may be even more costly for ratepayers than DSM. However, the facts today do not in any way indicate this deferral DSM value is present. In particular, Hydro's updated 2017 Resource Planning Assumptions and Analysis document[199] indicates that under base assumptions, no new generation resources are required until 2039/40 for energy (2040/41 for capacity). That document also indicates that if no DSM were undertaken at all from the 2017 DSM Update programs, small deficits would begin to start in 2032/33 for energy (2030/31 for capacity, though small capacity shortfalls are easily addressed). Given this is over 15 years in the future, and involves significant assumptions regarding load forecasts, export contracts, energy market structure, and internal Hydro policies, there is no reason to think that a major new plant would even need to be built for this time period if capital spending were desired to be avoided. For example, these are only deficits on a prospective basis under the worst drought conditions, and multiple small resources could be identified in the meantime which could satisfy the requirement if the shortfall was identified as persistent over the next few of years of resource planning (examples could include staged modest refurbishment of Pointe du Bois units, contracted imports for backup purposes, adjusted policies regarding reliance on export market purchases, or indeed smaller incremental resources or additional renewable generation such as utility-scale solar and wind, customer-sited load displacement projects, or scaled up DSM programs to see a ramp-up after the current financial pressures have receded, such as in 5-7 years).

The key conclusion is that the PUB's findings at NFAT continue to be ignored by Hydro. The PUB had concluded that Hydro failed to keep DSM as a resource for Integrated Resource Planning, but rather lumped the same DSM plan into each future scenario, even in scenarios where more DSM may be valuable for matching resource needs and loads. Today, Hydro continues to treat DSM as a guaranteed resource across all future scenarios, even where less DSM would be advised for matching resources needs and loads. There is no assessment by Hydro of the appropriate IRP level of DSM, no comparison of the cost effectiveness or economic efficiency of any given DSM level, and no apparent recognition that both its own evidence, and that of Boston Consulting, suggest that a significant portion of the financial pressures Hydro highlights could be addressed by sensible revisions to the assumed level of DSM activity in GRA forecasts.

6.3.3 Efficiency Manitoba Act

A potential challenge that may face Hydro today in regard to properly treating DSM in an Integrated Resource Planning context is the coming implementation of the *Efficiency Manitoba Act*. This new legislation

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[199] PUB/MH II-45a-e – Attachment 1

prescribes a delivery model for DSM that differs from the Hydro-focused delivery that has occurred to date.[200]

The *Efficiency Manitoba Act* is one part of the Government of Manitoba's response to the PUB's NFAT report. That response included both a specified intent to implement IRP, and an intent to establish a new arm's length agency.[201] The *Efficiency Manitoba Act* makes specific reference to a "savings target"[202] that, at least at the outset, is fixed at a given value regardless as to the facts of the Resource Plan. There are two ways to consider the target:

1) The *Efficiency Manitoba Act* is a rejection of Integrated Resource Planning, and intends to achieve the cited 1.5%/year savings target notwithstanding any evidence received from time-to-time in regards to the appropriateness and cost effectiveness of the target; or,
2) the *Efficiency Manitoba Act* is intended to operate within an Integrated Resource Planning framework, and the target is simply a starting point that is intended to be adjusted to reflect the facts as they are updated.

On balance, it appears the second reading is appropriate, for the following reasons:

1) The Act was accepted as an idea at the same time as the concept of IRP was endorsed by the Minister.
2) The Act specifically notes that the intent is to achieve a cost-effective result, including sections 9(f) regarding the need to indicate the cost effectiveness of the plan, 11(4)(b) the requirement for the PUB to consider the cost-effectiveness of the plan, and 16(1)(b) regarding the need to have an independent assessor confirm he cost-effectiveness of the plan as carried out.
3) The Act specifically notes that the long-term purpose of Efficiency Manitoba is to achieve rate benefits for Manitobans, as per the Mandate section of the Act, section 4(1)(c): "The mandate of Efficiency Manitoba is to … mitigate the impact of rate increases and delay the point at which capital investments in major new generation and transmission projects will be required by Manitoba Hydro to serve the needs of Manitobans." At this time, there is no prospect of rate increases tied to future capital investment for bulk power to be avoided.

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[200] Tab 3, page 12.
[201] Mandate letter to the Minister of Crown Services, May 3, 2016, page 2. Available online: https://www.gov.mb.ca/asset_library/en/executivecouncil/mandate/hon_ron_schuler.pdf
[202] Efficiency Manitoba Act, Bill 19, Part 3, available online: https://web2.gov.mb.ca/bills/41-2/b019e.php

4) The Act also specifically notes that Manitoba Hydro should be heard and make submissions on a review of an efficiency plan, presumably to reflect Hydro's knowledge and plans for future capital investment that could be deferred.

5) The explanatory notes to the Act when it was first introduced as Bill 19 specifically note: "In recognition of the benefits received by Manitoba Hydro from the efforts of Efficiency Manitoba, Manitoba Hydro is responsible for funding Efficiency Manitoba's operations."[203] The benefits to Manitoba Hydro clearly only arise to the extent that the DSM program being delivered is providing net benefits to the utility accounts, financial results and net revenues.

6) While the Act specifies a pre-determined value as the "savings target" in section 2, the Act also specifically notes that the target is not in practice fixed, as follows.[204]

    a. Section 4(2)(b)(i) notes that the agency should provide advice to the government and to Hydro regarding "…the appropriateness of the savings target…"

    b. Section 11(5(b) provides that the PUB can recommend "a decrease in a savings target if it is reasonably satisfied that the existing savings target is not in the public interest".

    c. Section 38(1) notes that the Lieutenant Governor in Council may, by regulation, adjust the savings target.

In short, the above structure suggests that any savings plan from Efficiency Manitoba should be viewed from an IRP context, tied to the ability of DSM to achieve economic benefits (including rate benefits) from export sales or deferring new major generation and transmission. Where such benefits do not exist, or do not exist to the degree needed to support a 1.5%/year savings target, such a target should not be assumed to be the default level to pursue.

In addition, recent news regarding the potential for revenues from a potential Carbon Tax being devoted to efficiency related uses suggests a basis for funding DSM that is not justified by proper IRP, which would reduce the net costs to Hydro.

Note also that Hydro's GRA proposals effectively incorporate the same outcome as is noted above – that the best forecast for the cost Efficiency Manitoba should be based on a target below 1.5%/year, in that Hydro did not include the full extra costs of achieving a 1.5% per year reduction in GRA forecasts.

Also note that curtailed DSM spending would benefit not only net income but also Hydro's cash position and debt retirement opportunities.

[203] Efficiency Manitoba Act, Bill 19, available online: https://web2.gov.mb.ca/bills/41-2/b019e.php
[204] Efficiency Manitoba Act, Bill 19, available online: https://web2.gov.mb.ca/bills/41-2/b019e.php

6.3.4 Recommendations regarding DSM

For the current hearing, given the above facts, it does not appear Hydro has appropriately responded to current conditions or the pending DSM agency. Hydro's forecasts for DSM spending are substantial and well beyond what can be justified on economic and cost effectiveness grounds. Significant adverse financial impacts are expected in the short and long-term from the level of spending targeted by Hydro, and this spending remains below the levels expected to achieve the hard value of 1.5%/year savings set out in the Act.

Under these circumstances, it is appropriate to consider the likelihood that Efficiency Manitoba, its Minister, or the PUB will make a finding that continuing large-scale DSM is not cost effective for at least the next 5-7 or so years. Hydro should take this likelihood into account in its planning and budgeting. In assessing rate levels proposed in this GRA, the PUB should similarly consider that a beneficial adjustment of multiple percentage points in Hydro's debt ratio can be expected within the next decade from undertaking sensible, realistic and cost effective adjustments to the DSM projections. Such an adjustment would serve as a beneficial factor towards ameliorating the need for sustained 3.95% future rate increases.

A separate concern arises in respect of $48.8 million of past DSM program budgets that have gone unspent, along with plans to allocate this budget in future to DSM programming.[205] At this time, Hydro's forecasts simply carry the balance indefinitely.[206] As the deferral is in effect a further supplement to the DSM programming already included in IFF16, this further exacerbates concerns about excessive investment in uneconomic resources at a time when they are least needed, and most unaffordable given Hydro's financial position.

[205]Appendix 3.1, page 31 and PUB/MH I-1a
[206] MIPUG/MH I-6c page 6

7.0 COST OF SERVICE IMPLEMENTATION & RATE DESIGN

Manitoba Hydro's Cost of Service (COS) methodology has recently been reviewed and confirmed in the proceeding leading to PUB Order 164/16. The outcome of the proceeding was a number of recommendations on Hydro's Cost of Service methodology which have now been implemented.

The first implementation details were addressed as part of the Prospective Cost of Service Study ("PCOSS") presented as PCOSS14 for the COS review Compliance Filing application on February 21, 2017. This led to a number of PUB decisions regarding implementation.

In this review, Hydro has filed PCOSS18, based on the 2017/18 rate setting period (IFF16), which continues to largely reflect methodology directed in Order 164/16. Some relatively small changes have been made to the PCOSS methodology, which were not fully included in the compliance filing from the COS hearing.[207]

Among the items that were not fully addressed in the PCOSS14 compliance filing were customer service cost allocations related to: Billings (C11), Meter Reading (C15), Meter Investment (C40), Electrical Inspections (C14) and Customer Service General Costs (C10) (as directed in Order 164/16). This matter (and in particular the C10 component) is further reviewed below.

Table 7.1 below shows the results of PCOSS18, focusing on the functionalized cost breakdown by customer class and the corresponding forecast revenue.

As shown in Table 7.1, system costs for generation and transmission are allocated to all classes. The total costs represent a value that reflects Hydro's entire system (including that portion serving exports) allocated to domestic customers. To offset this clear overallocation (since large portions of the system are serving exports not domestic customers), a share of export revenues is credited to each class. This allocation is not any form of subsidy (as suggested by the Boston Consulting materials in PUB MFR 72),[208] but rather a reasonable credit to domestic ratepayers for the extra costs they incur to permit service of power to export customers.

It should be noted that after this allocation, each kW.h of energy consumed by smaller distribution customers, like residential customers, is somewhat more costly than the larger class like General Service Large. This reflects two factors: first, residential have a higher cost load pattern (due to the tendency to impose peak loads at peak times for the system, which drives the need for investment for capacity purposes), and second, because each residential kW.h is delivered at a lower voltage leading to greater

[207] Tab 8, pages 3 - 4
[208] PUB-MFR-72, pdf page 205 of 615

energy and line losses being experienced before the kW.h is delivered. Similarly, these smaller classes are also exposed to the costs of the distribution system, which are not used by, or allocated to, the large users.

Table 7.1 shows that for the major industrial customers, Hydro's measured cost is $160.6 million, but the class pays a total of $180.5 million, or almost $20 million/year above costs. On an average unit cost basis, this represents 3.57 cents/kW.h in costs, and 4.01 cents/kW.h in revenue respectively. As rates exceed costs by 0.44 cents/kW.h, on a base rate of 3.57 cents/kW.h, the Revenue to Cost Comparison (RCC) ratio is calculated as 112.33% (meaning rates are 12.33% above costs). GSL 30-100 kV is similarly paying rates 13.04% above costs. This RCC ratio is higher than the ratio calculated by Hydro (108.6%), as Hydro oddly includes the export revenue allocation into the revenue portion for each class, even though this rate is not subject to adjustment (Hydro's calculation is based on the same $20 million by which rates exceed costs, but Hydro measures the percentage as a ratio to the sum of domestic revenue plus the share of export revenue, which is not meaningful for considering whether domestic rates should be adjusted).

The impact of this high RCC ratio is reviewed further in the Rate Design Section 7.2.

Included in Table 7.1 is the net export allocation to each customer class. This total amount, forecast at $417 million, is the result of total revenue from exports over the forecast period 2017-2018 ($455 million) less a small amounts of costs that are directly assigned to exports ($38 million – made up of directly assigned share of water rentals ($34.2 million), variable O&A ($3.5 million) and costs of the Affordable Energy Fund ($0.5 million))[209].

Figure 7-1 provides a graphical representation of the values in Table 7-1.

[209] Tab 8, page 19 of 34

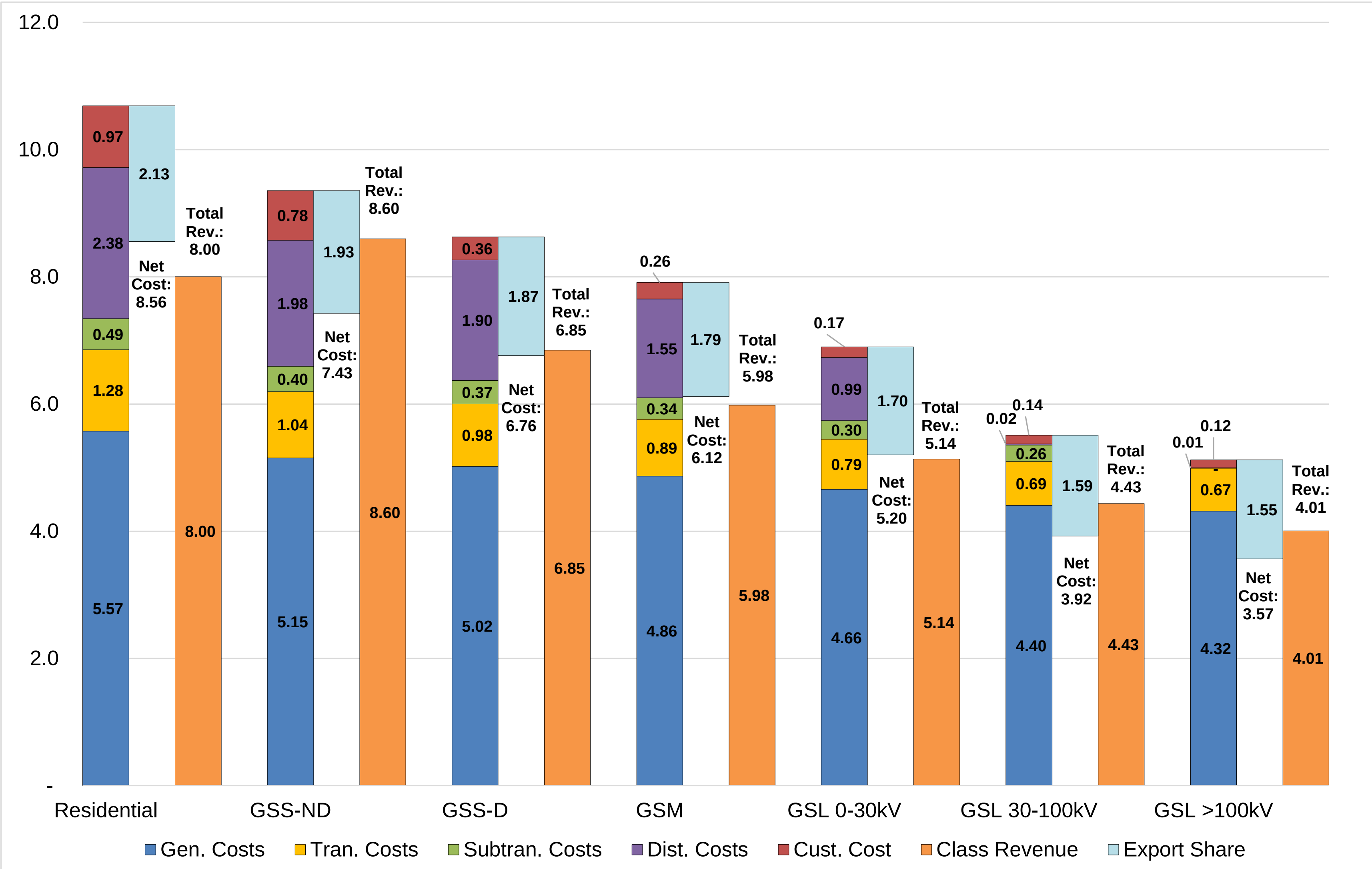
Table 7-1: PCOSS18 Functionalized Cost to Revenue Comparison ($Millions and cents/kW.h) – All Rate Classes[210]

	Residential		GSS-ND		GSS-D		GSM		GSL<30kV		GSL 30-100kV		GSL>100kV	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs														
1 Generation Costs	*$422.92*	5.57	*$83.60*	5.15	*$107.75*	5.02	*$155.89*	4.86	*$81.30*	4.66	*$69.53*	4.40	*$194.55*	4.32
2 Transmission Costs	*$96.88*	1.28	*$16.92*	1.04	*$20.98*	0.98	*$28.62*	0.89	*$13.77*	0.79	*$10.90*	0.69	*$30.31*	0.67
3 Export Share	*($161.91)*	-2.13	*($31.31)*	-1.93	*($40.10)*	-1.87	*($57.47)*	-1.79	*($29.61)*	-1.70	*($25.05)*	-1.59	*($70.04)*	-1.55
4 **Bulk Power Costs**	***$357.89***	***$4.72***	***$69.22***	***$4.27***	***$88.64***	***$4.13***	***$127.04***	***$3.96***	***$65.46***	***$3.75***	***$55.38***	***$3.51***	***$154.82***	***$3.44***
5 **plus: Subtransmission-related**	***$37.24***	**0.49**	***$6.46***	**0.40**	***$7.98***	**0.37**	***$10.84***	**0.34**	***$5.18***	**0.30**	***$4.08***	**0.26**	***$0.00***	**0.00**
6 Distribution	*$180.23*	2.38	*$32.17*	1.98	*$40.68*	1.90	*$49.82*	1.55	*$17.23*	0.99	*$0.28*	0.02	*$0.24*	0.01
7 Cust. Serv.	*$73.65*	0.97	*$12.66*	0.78	*$7.80*	0.36	*$8.30*	0.26	*$2.92*	0.17	*$2.18*	0.14	*$5.59*	0.12
8 **plus: Distrib. and Cust. Serv.**	***$253.88***	**3.35**	***$44.83***	**2.76**	***$48.48***	**2.26**	***$58.12***	**1.81**	***$20.15***	**1.15**	***$2.46***	**0.16**	***$5.83***	**0.13**
9 **Total Assigned Costs**	***$649.00***	**8.56**	***$120.50***	**7.43**	***$145.10***	**6.76**	***$195.99***	**6.12**	***$90.79***	**5.20**	***$61.92***	**3.92**	***$160.65***	**3.57**
Rates														
10 **Total PCOSS Sales Revenue**	***$607.11***	**8.00**	***$139.48***	**8.60**	***$146.98***	**6.85**	***$191.74***	**5.98**	***$89.65***	**5.14**	***$70.00***	**4.43**	***$180.46***	**4.01**
Surplus/Shortfall														
11 **Rates compared to costs** (109)	***($41.90)***	**-0.55**	***$18.98***	**1.17**	***$1.88***	**0.09**	***($4.26)***	**-0.13**	***($1.14)***	**-0.07**	***$8.07***	**0.51**	***$19.81***	**0.44**
12 Revenue-to-Cost Ratio (line 10/line 9)	***93.5%***		***115.7%***		***101.3%***		***97.8%***		***98.7%***		***113.0%***		***112.3%***	
13 Total Class Metered Energy (GW.h)	*7,586*		*1,623*		*2,146*		*3,204*		*1,745*		*1,579*		*4,505*	

	Lighting		SEP		Domestic Total		Diesel		Exports		Total System	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs												
1 Generation Costs	*$4.03*	4.90	*$0.58*	2.27	*$1,120.16*	4.98	*$8.60*	59.12	*$38.16*	0.42	*$1,166.92*	3.68
2 Transmission Costs	*$0.72*	0.88	*$0.09*	0.35	*$219.20*	0.97	*$0.00*	0.00	*$0.00*	0.00	*$219.20*	0.69
3 Export Share	*($1.48)*	-1.80	*$0.00*	0.00	*($416.99)*	-1.85	*$0.00*	0.00	*$416.99*	4.55	*$0.00*	0.00
4 **Bulk Power Costs**	***$3.28***	***$3.98***	***$0.67***	***$2.63***	***$922.38***	***$4.10***	***$8.60***	***$59.12***	***$455.15***	***$4.97***	***$1,386.12***	***$4.38***
5 **plus: Subtransmission-related**	***$0.27***	**0.33**	***$0.00***	**0.00**	***$72.06***	**0.32**	***$0.00***	**0.00**	***$0.00***	**0.00**	***$72.06***	**0.23**
6 Distribution	*$17.04*	20.68	*$0.02*	0.09	*$337.72*	1.50	*$0.40*	2.72	*$0.00*	0.00	*$338.11*	1.07
7 Cust. Serv.	*$0.91*	1.11	*$0.04*	0.17	*$114.05*	0.51	*$0.00*	0.00	*$0.00*	0.00	*$114.05*	0.36
8 **plus: Distrib. and Cust. Serv.**	***$17.95***	**21.78**	***$0.07***	**0.26**	***$451.76***	**2.01**	***$0.40***	**2.72**	***$0.00***	**0.00**	***$452.16***	**1.43**
9 **Total Assigned Costs**	***$21.50***	**26.09**	***$0.74***	**2.89**	***$1,446.20***	**6.43**	***$9.00***	**61.84**	***$455.15***	**4.97**	***$1,910.34***	**6.03**
Rates												
10 **Total PCOSS Sales Revenue**	***$21.57***	**26.17**	***$0.84***	**3.31**	***$1,447.83***	**6.44**	***$7.37***	**50.66**	***455.15***	**4.97**	***1,910.34***	**6.03**
Surplus/Shortfall												
11 **Rates compared to costs** (109)	***$0.07***	**0.08**	***$0.11***	**0.42**	***$1.63***	**0.01**	***($1.63)***	**-11.19**	***0.00***	**0.00**	***0.00***	**0.00**
12 Revenue-to-Cost Ratio (line 10/line 9)	***100.3%***		***114.4%***		***100.1%***		***81.9%***		***100.0%***		***100.0%***	
13 Total Class Metered Energy (GW.h)	*82*		*26*		*22,496*		*15*		*9,166*		*31,677*	

[210] Functionalized Cost breakdown by rate class per Hydro's 'Rudimentary Model of PCOSS18' tabs 'C Tables Proces', 'D Tables Proces', 'E Tables Proces' and 'Direct Costs', Sales Revenue and Net Export Revenue Allocation from tab 'RCC Summary', Total Class Metered Sales from tab 'Cust, Demand and Energy Summary'. Affordable Energy Fund included as direct-assigned export generation costs ($0.5 million) with variable O&M ($3.5 million) and water rentals ($34.2 million) as provided in Tab 8, page 19 of 34.

Figure 7-1: PCOSS18 Functionalized Cost to Revenue Comparison (cents/kW.h) – Major Domestic Rate Classes



7.1 CUSTOMER SERVICE ALLOCATION CHANGES

Manitoba Hydro has proposed allocation changes to the following allocators in response to direction flowing from Order 164/16 (page 81):

- Customer Service General Costs (C10),
- Allocation of Billings (C11),
- Meter Reading (C15),
- Electrical Inspections (C14), and
- Meter Investment (C40).

The percentage allocation weightings between PCOSS18 and PCOSS14-Amended (Hydro's last filed Cost of Service Study prior to Board Order 164/16) is provided in the table below.

Table 7-2: Hydro's Proposed Customer Service Allocator Changes[211]

Allocation %	Customer Service General (C10, C13, C23)		Billings (C11)		Collections (C12)	
	PCOSS18 (C10,C13,C23)	PCOSS14 - Amend. (C10)	PCOSS18	PCOSS14 - Amend.	PCOSS18	PCOSS14 - Amend.
Res	44.3%	44.5%	85.8%	83.8%	91.0%	74.7%
GSS-ND	10.2%	18.5%	9.3%	11.6%	7.0%	19.8%
GSS-D	10.7%	4.3%	2.2%	2.9%	1.7%	4.7%
GSM	14.0%	13.7%	2.0%	0.5%	0.3%	0.8%
GSL 0-30kV	5.1%	7.7%	0.4%	0.2%	0.0%	0.0%
GSL 30-100kV	4.0%	5.5%	0.1%	0.0%	0.0%	0.0%
GSL >100kV	10.2%	5.2%	0.0%	0.0%	0.0%	0.0%
ARL	1.6%	0.6%	0.2%	0.9%	0.0%	0.0%
Total %	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Category Cost ($000)	53,888	46,560	27,628	28,210	14,915	18,242

Allocation %	Inspections (C14)		Meter Reading (C15)		Meter Investment (C40)	
	PCOSS18	PCOSS14 - Amend.	PCOSS18	PCOSS14 - Amend.	PCOSS18	PCOSS14 - Amend.
Res	37.4%	47.1%	82.9%	89.1%	24.6%	51.9%
GSS-ND	48.8%	41.4%	10.8%	7.9%	9.6%	10.7%
GSS-D	11.5%	9.7%	5.2%	1.9%	42.8%	26.8%
GSM	1.9%	1.5%	0.9%	0.9%	11.7%	7.7%
GSL 0-30kV	0.3%	0.2%	0.1%	0.1%	6.1%	1.5%
GSL 30-100kV	0.0%	0.0%	0.0%	0.0%	2.8%	1.0%
GSL >100kV	0.0%	0.0%	0.0%	0.0%	2.4%	0.4%
ARL	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total %	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Category Cost ($000)	4,398	3,824	13,218	11,976	10,181	5,899

As shown in the table above, most of the customer service categories are of limited to no relevance to the GSL classes, which is as expected. The topics of concern relate primarily to changes to the C10, C13, and C23 cost category.

The functionalized cost category known as 'C10' previously included a number of general Customer Service activities that did not fit into the other, more specific, categories. During review of PCOSS14 in the 2015 Cost of Service Methodology Review, only limited detail was provided by Hydro to decipher the actual services being provided in C10, particularly as the largest subcategory was simply called 'Customer Service (Other)'. As well, the allocation of these costs was purportedly based on an analysis undertaken to estimate the efforts that various departments devoted to each customer class, weighted by the budget of each

[211] PCOSS18 as provided in Tab 8.2 Allocation Program, PCOSS14-Amended as provided in the 2015 Cost of Service Methodology Review Allocation Program, Appendix 3.2. SEP GSM is included in GSM, SEP GSL is included in GSL <30kV. C10, C13 & C23 for PCOSS18 are weighted based on cost allocations to compare to C10 from PCOSS14-Amended.

department, but these budgets did not match the costs that the PCOSS was using C10 to allocate.[212] This method for allocation had been introduced in 2001 but had not been reviewed since PCOSS11.[213]

The PUB, in Order 164/16, directed that certain specific costs in the C10 Customer Service sub-category should not be allocated to GSL 30-100kV or GSL>100kV customers unless and until Manitoba Hydro can provide a complete description of these costs. In this description, Manitoba Hydro was to:

- Explain why these costs apply to the GSL classes,
- Confirm that these costs are not already subsumed within the costs categorized as Key Accounts and Major Accounts, and
- Justify why the chosen weightings for the allocator are appropriate for these costs.[214]

For PCOSS18, Hydro reviewed the C10 cost category, resulting in a disaggregation into three separate categories:

- **C10 General Customer Service ($13.9 million)** – In regard to this new category, Hydro notes: "The activities now reflected in this General category are those activities that Manitoba Hydro views as public safety-related, the costs of which are allocable to all customers."[215] This is listed to include education & safety ($1.2 million), call center outage reports ($1.2 million), rates & regulatory ($3 million), marketing R&D ($1.3 million), line locates ($4.1 million) and building moves and safety watches ($3.1 million). These costs are allocated to all customers based on class revenue. Hydro did not explain how many of these categories, such as "rates and regulatory", fit the description of C10 as being related to public-safety.
- **C23 Industrial & Customer Solutions ($4.3 million)** – Activities in this department are focused on GSL classes including consultation, service extension, billing-related inquires, power quality and general inquiries. These costs are allocated only to the GSL classes based on class revenue proportions.
- **C13 Customer Service – Small Customers ($21.2 million)** – Costs aimed at smaller customers including customer & community service work, general inquiries, power quality and service extensions. These costs are allocated to all customers other than the GSL classes based on class revenue proportions.[216]

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[212] MIPUG/MH I-4a-c from 2015 Cost of Service Methodology Review
[213] PUB/MH I-57 from 2015 Cost of Service Methodology Review
[214] Order 164/16, December 20, 2016, pages 80 – 81 of 116
[215] Tab 8 page 13
[216] Tab 8, page 13 & Appendix 8.1, page 18.

Hydro has proposed to change the allocation weighting for each of these cost categories to an allocator based on revenue weightings.[217]

Hydro has not provided a full comparison to the total costs of C10/C13/C23, but instead focuses on a summary of the operating cost component ($39.4 million) at PCOSS18.[218] This ignores depreciation ($2.9 million) and allocation of common costs ($11.5 million) to come to the full impact of the C10/C13/C23 categories, as shown above in Table 7-2; for reasons of data availability, the remainder of this section focuses only on the operating cost component. However, the noted concerns related to all components.

A comparison of the C10/C13/C23 operating costs compared to the previous method on a customer class basis is provided in Table 7-3 below.

Table 7-3: Customer Class Comparison of C10, C13 and C23 Operating Costs for PCOSS18 vs. PCOSS14 Amended ($ Millions)[219]

	Customer Service Activity - Operating Costs	RES	GSS-ND	GSS-D	GSM	GSL 0-30kV	GSL 30-100kV	GSL >100kV	A&RL	Total
C10	Education and Safety	0.5	0.1	0.1	0.2	0.1	0.1	0.2	0.0	**1.2**
C10	Contact Center - Outages	0.5	0.1	0.1	0.2	0.1	0.1	0.2	0.0	**1.2**
C10	Rates & Regulatory	1.3	0.3	0.3	0.4	0.2	0.1	0.4	0.0	**3.0**
C10	Marketing R&D	0.6	0.1	0.1	0.2	0.1	0.1	0.2	0.0	**1.3**
C10	Line Locates	1.7	0.4	0.4	0.5	0.3	0.2	0.5	0.1	**4.1**
C10	Building Moves & Safety Watches	1.3	0.3	0.3	0.4	0.2	0.2	0.4	0.1	**3.1**
C23	Industrial & Commercial Solutions	-	-	-	-	1.1	0.9	2.3	-	**4.3**
C13	Customer & Community Service Work	2.3	0.5	0.6	0.7	-	-	-	0.1	**4.3**
C13	General Inquiries	1.1	0.3	0.3	0.4	-	-	-	0.0	**2.0**
C13	Power Quality	0.6	0.1	0.1	0.2	-	-	-	0.0	**1.0**
C13	Service Extensions	7.6	1.8	1.8	2.4	-	-	-	0.3	**13.9**
	Total	**17.5**	**4.0**	**4.2**	**5.5**	**2.0**	**1.6**	**4.0**	**0.6**	**39.4**
C10	Proposed Allocation %	41.9%	9.6%	10.2%	13.3%	6.2%	4.8%	12.5%	1.5%	100.0%
C23	Proposed Allocation %	0.0%	0.0%	0.0%	0.0%	26.4%	20.6%	53.0%	0.0%	100.0%
C13	Proposed Allocation %	54.8%	12.6%	13.3%	17.4%	0.0%	0.0%	0.0%	1.9%	100.0%
	PCOSS18 Combined Percentage Allocation	***44.3%***	***10.2%***	***10.7%***	***14.0%***	***5.1%***	***4.0%***	***10.2%***	***1.6%***	***100.0%***
C10	**PCOSS14-Amended Proposed Allocated Costs**	**17.2**	**7.1**	**1.7**	**5.3**	**3.0**	**2.1**	**2.0**	**0.2**	**38.7**
	PCOSS14-Amended Allocation %	*44.5%*	*18.5%*	*4.3%*	*13.7%*	*7.7%*	*5.5%*	*5.2%*	*0.6%*	*100.0%*

From the table above, the operating costs related to customer service are proposed to be allocated to the GSL categories total $7.6 million, as follows: $2.0 million to GSL 0-30kV, $1.6 million to GSL 30-100 kV, and $4.0 million to GSL >100kV. This compares to a total of $7.1 million under the previous approach, allocated $3.0 million to GSL 0-30kV, $2.1 million to GSL 30-100kV, and $2.0 million to GSL >100kV.

[217] Manitoba Hydro 2017/18 and 2018/19 GRA, Tab 8, page 13 of 34.
[218] Tab 8.1, PCOSS18, pages 18-19
[219] PCOSS18 customer class share provided in MIPUG/MH I-11a, PCOSS14 Amended customer class C10 costs from Model of PCOSS14 (Amended) spreadsheet, tab 'C Tables Proces' for C10 allocated costs. Note: SEP GSM is included in the GSM class and SEP GSL is included in the GSL 0-30kV class.

Although total costs associated with this category has stayed largely the same ($38.7 million to $39.4 million), the GSL share has increased, and for the largest customers, the GSL >100kV class, the share of costs has doubled under Hydro's proposed methodology. This appears to be largely a result of Hydro's proposed allocation method, using revenue weightings (tied to the total bill paid by customers) rather than metrics based off of customer numbers. Hydro's other customer service cost allocators are based on customer counts, which is a reasonable approach for customer service related functions.

Looking to Table 7-3 above, the following observations are noted:

- C23 relates to customer service functions that are strictly limited to General Service Large customers. These costs represent a department that provide the main point of contact for Hydro's key accounts, and it is appropriate that these costs are targeted to the three GSL classes, as proposed by Hydro. Further, the scale of services provided could be reasonably considered to link to customer complexity and size, so a revenue allocator appears reasonable.
- Similarly, C13 costs relate to some comparable functions as C23, but for service delivered to smaller customers. As a result, the complementary allocation is proposed – costs should be allocated to all classes other than GSL. This is also appropriate.
- For the C10 categories of Rates and Regulatory, and Education and Safety an allocation to all classes is appropriate. As to allocator, a revenue linked allocator is within typical utility practice for Rates and Regulatory, and is appropriate. With respect to Education and Safety costs, portions of these costs would appear to relate to ensuring the safety of the public around Hydro's facilities[220] and as such the programs link to assets, and a revenue based allocation is not unreasonable. This would be an overstatement to GSL, however, as the Education and Safety category is listed to include District Office costs,[221] which would appear to include functions such as payment windows which are not of relevance to major customers. However, on bulk, the cost allocation for these categories is likely reasonable.

For the remaining costs, it appear that Hydro has over allocated these costs to the GSL classes, and particularly for the largest customers in the GSL 30-100kV and GSL >100kV classes, as follows:

- <u>Contact Centre – outages</u> ($0.4 million to GSL, out of $1.2 million) – according to Hydro, while the contact centre is the initial point of contact for all customers regarding billings, collections, and call before you dig, this cost is specific to fielding outage related calls. In the case of GSL customers, there are a very small number of customers and for many, direct contacts are available through

[220] MIPUG/MH I-11a-f page 3.
[221] Appendix 8.1, page 18.

Hydro's Industrial and Commercial Solutions Division.[222] It would appear likely that the vast majority of costs in this category would relate to maintaining a contact centre to handle outage issues with other classes that have large numbers of customers. Allocating over 1/3 of the costs of this function to GSL customers (a total of 377 accounts)[223] appears highly excessive. If any costs are to be allocated from this category to all customers including GSL, it should at most be on the basis of customer count.

- Marketing R&D ($0.4 million to GSL, out of $1.3 million) – includes activities such as creating marketing plans, customer surveys, maintaining customer databases, and enhancing business development in the province. While not specifically related to distribution level customers, it does not appear that large parts of this category bears any linkage to the GSL customers – such as maintaining customer databases. It also should be expected that (a) the Industrial & Commercial solutions department would undertake some of this work where it directly relates to GSL customers and (b) that the majority of this work would be done for residential, GSS and GSM customers as the predominant customer base. For this category, any GSL weighting should at most be based on customer counts.
- Line locates ($1.0 million to GSL, out of $4.1 million) – Hydro notes that this category primarily relates to a service provided for distribution lines.[224] GSL >100kV and GSL 30-100kV customers are not served by distribution facilities. The cost allocation should reflect the dominant function driving the cost, and as such should be moved to the distribution function. If a small portion of the cost can be tracked related to transmission line locates, a relevant percentage could be included in the transmission function. Under no circumstance should costs be allocated tied to revenue, particularly on overall rates paid tied to such matters as generation functions, as is currently proposed by Hydro.
- Building moves & safety watches ($0.8 million to GSL out of $3.1 million total cost - approximately 60% relates to building moves and 40% relates to safety watches)[225] – primarily relates to distribution related services:
    - Building moves ($1.83 million)[226] is for temporary disconnect and reconnect of utility facilities for building or structure moves originating in the province. Manitoba Hydro states that it incurs the cost of inspecting routes during normal working hours and shares the costs 50/50 for accompany movers to perform switching as required. Full costs are

[222] PUB/MH I-11f
[223] Appendix 8.1, page 3
[224] MIPUG/MH I-11b&c
[225] MIPUG/MH I-11d
[226] MIPUG/MH II-8c

recovered for buildings moving to Manitoba from outside the province.[227] However, of the total $1.83 million expense, despite claims regarding cost recovery, Hydro notes that only $300 million was collected as offsetting revenue[228] (and further, for some reason the revenue is not allocated at the same weightings as the expense, with residentials receiving a higher weighted allocation (47% of revenue) and GSL 30-100kV and GSL >100kV receiving a lower weighted allocation than the allocation used for the expenses (4% and 10% respectively).[229] Manitoba Hydro confirmed that the costs primarily relate to distribution lines.[230]

- Safety watches ($1.2 million) relates to costs incurred for Hydro to supervise residential homeowners and contractors working in close proximity to facilities. Hydro incurs the first man hour and then splits remainder of costs 50/50 during normal working hours.
- In regard to the above two categories, it appears to not be in dispute that the services primarily relate to distribution assets, and to residential customers. No basis has been provided to justify collection of $0.8 million of these costs from the GSL classes. If a small portion of building moves can be linked to transmission, that cost should be moved to the transmission function, otherwise these costs should be tracked as part of the distribution function and allocated only to those customers who make use of this function.

The total of the above categories allocated to GSL customers that is not supported based on the evidence is $2.6 million/year. This amount is material and requires adjustment to ensure the COS study is properly reflecting the costs incurred to serve each function and class.

Hydro has not followed the PUB direction from 164/16 regarding costs in C10.[231] There is no information provided that explains why these costs apply to GSL and why these costs are not already subsumed within the costs categorized in C23 – Industrial & Commercial Solutions. The information that has been provided (other than for the Rates & Regulatory account) does not justify allocation to GSL customers, and if anything explicitly supports the opposite outcome (that these costs are largely related to distribution level activities).

[227] MIPUG/MH I-11d
[228] MIPUG/MH II-8a-c
[229] MIPUG/MH II-8c
[230] MIPUG/MH I-11a-f page 4
[231] Order 164/16, December 20, 2016, pages 80 – 81 of 116

7.2 RATE DESIGN

The results of PCOSS18 in the relation between costs and revenues are shown in Table 7-1 earlier in this section. As shown in Table 7-1, various classes require rate adjustments over time (up or down) to bring them in line with the overall target revenue:cost ratio "zone of reasonableness" (95% to 105%).

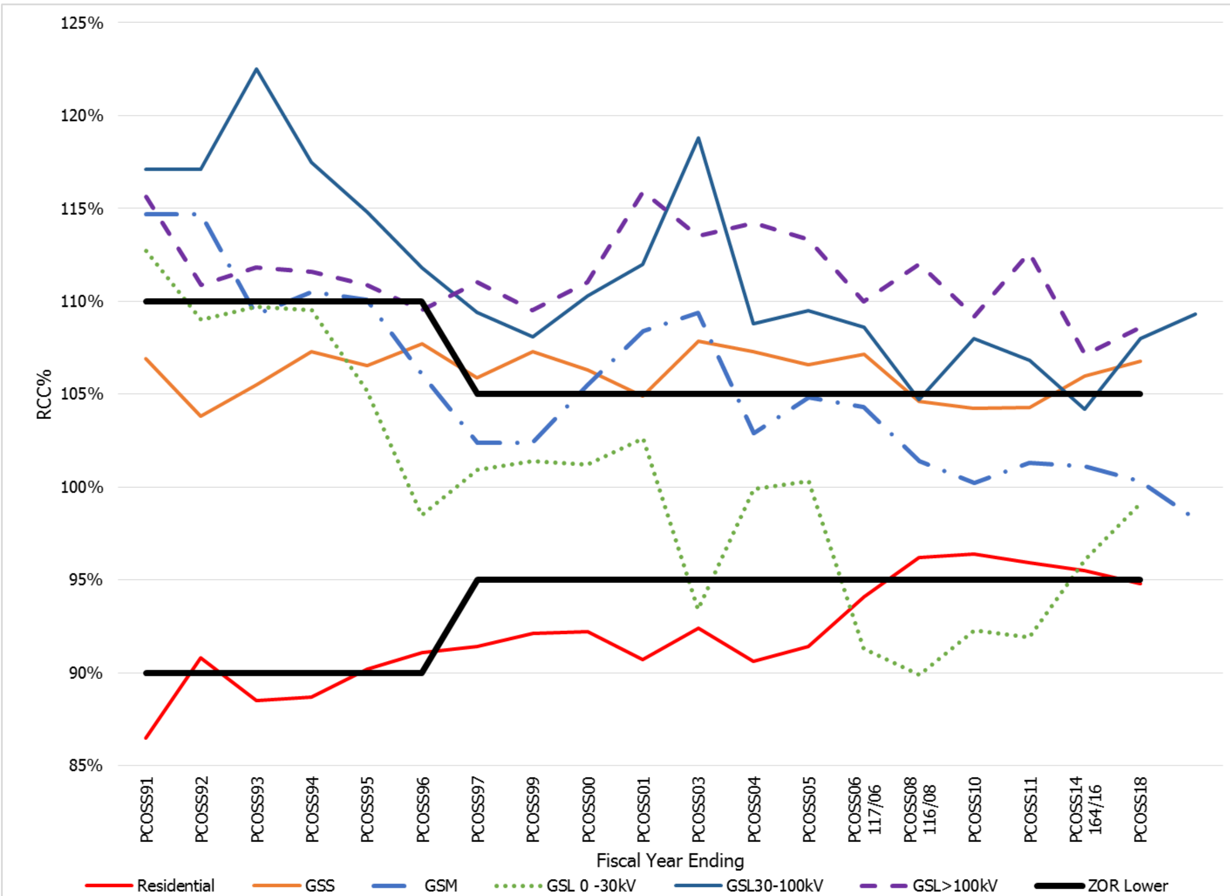
The above noted issues of the GSL classes (and others) paying above the zone of reasonableness requires attention. This issue in Manitoba has seen delays in resolution for many years while Hydro attempted to address getting a finalized and approved COS methodology.

Over a long period of time, rate changes have been across-the-board, or equal percentages to all rate classes (with the exception of one in the 2003, when the Board ordered a 1% rate decrease for GSS customers and a 2% rate decrease for GSL >30 kV).[232] Hydro's zone of reasonableness, historically set at 95-105% since 1996, has long been implicitly accepted as reasonable for purposes of rate setting this jurisdiction, but Hydro has resisted rate changes as need to give effect to this zone. Prior to 1996, Hydro used a Zone of Reasonableness of 90-110% reflecting the imprecision in the COS methods at that time, which were in their infancy in Manitoba. Since that time, effectively all jurisdictions in Canada have moved to the largely industry standard 95-105% zone of reasonableness, ideally reaching unity (cost-based rates for all customers).

The long-term history of rates in relation to costs is shown in Figure 7-2 below:

[232] Board Order 7/03, page 103.

Figure 7-2: Revenue Cost Coverage Ratios by Customer Class[233]



Note that the results in Figure 7-2 are as reported in the respective PCOSS – as noted above this has a dampening effect on the true percentage by which each class faces rates over or under measured costs, due to the arithmetic Hydro applies to export revenues.

In this current GRA, Hydro suggests that a new widening of the zone of reasonableness to 90%-110% may be reasonable in light of historical precedence and continuity, ratemaking and policy objectives, the degree of variability in cost allocation methodologies and cost definition and the changing cost structure in future rate applications due to the significant infrastructure investment underway for Manitoba Hydro[234]. Such a revision would not be advisable. The basic premise for utility ratemaking is to recover rates that reflect costs – overall rates to reflect the costs of the utility, and between the classes, rates that reflect the costs to serve that class. Some jurisdictions, such as Newfoundland and Labrador, strictly target 100.00% for

[233] 1991-1994 and 1996 RCC ratios from MIPUG/MH/CR-2(b), Manitoba Hydro 1996/97 GRA. RCC ratios for 1995, 1997, 1999, 2001-2004 and 2006-2018 from Appendix 8.1, page 38, Manitoba Hydro 2017/18 & 2018/19 GRA. 2000 RCC ratios from MIPUG/MH I-30(a), Manitoba Hydro 2015/16 GRA. 2005 RCC ratios from MIPUG/MH I-21(f), Manitoba Hydro 2004 GRA.

[234] PUB/MH I-137a

setting industrial rates, which can, at times, undermine other rate redesign objectives such as rate stability. Outside of such consideration, there is no reasonable basis to ignore a valid, regulatory-approved COS result in setting rates by class.

For the GSL >100kV customers to even reach a 105% RCC a substantial one-time rate decreases would be required of approximately 0.26 cents/kW.h (GSL >100 kV costs at 3.57 cents/kW.h, at 105% this yields 3.75 cents/kW.h – compare to current rates at 4.01 cents/kW.h). To large power users, continuing to pay energy rates at a level this much higher than costs has implications to competitiveness and economics.

However, among the considerations that should be brought to bear on such rate adjustments is long-term stability. Hydro notes that Bipole III is coming into service, but is not yet included in the PCOSS. While a PCOSS fully incorporating Bipole III has not yet been prepared, it is clear that this asset will drive bulk power costs in the COS study notably higher (even when Bipole III costs are offset by the Bipole III revenue deferral amortization). This does not limit the Board from providing improvements to the RCC ratio by awarding lower than average rate increases to industrials of, for example, 1-2% below the average rate increase awarded (similar to the Board's decision in Order 7/2003), but does suggest caution in regards to large moves such as calculated above (i.e., a reduction of the full 0.26 cents/kW.h at one time is not advised).

7.2.1 Time of Use (TOU) Rates

Hydro had previously applied for Time of Use ("TOU") rates in the 2015/16 GRA; however the Board determined it would be addressed in the Cost of Service review, and these rates were ultimately not reviewed at that GRA[235]. In the Cost of Service review rate-related matters, including rate rebalancing, time-of-use rates and conservation rates were excluded from the scope of the Cost of Service methodology review to the next GRA[236] (i.e. this proceeding).

Hydro did not submit a TOU rate proposal in this GRA. Hydro is not proposing to implement TOU rates in this application as Hydro has generally only considered TOU rates as a mandatory change to the industrial rate schedule affecting all customers, and as a result under Hydro's concept of a TOU rate there would be 'winners and losers'. Specifically, some customers who would be charged this rate, such as high load factor customers who are unable to shift production to off-peak periods, would be burdened, essentially funding any bill reductions to the customers that can make use of off-peak time periods to reduce costs.[237] This is a difficult challenge to the implementation of Hydro's concept at the best of times, but particularly so when facing a 7.9% rate increase proposal.

[235] Order 73/15, page 89 of 90
[236] Order 26/16, page 16
[237] Tab 9, page 4

The issue for this hearing is that Hydro rates continue to offer industrial customers a very limited scope of ways to control costs. In many other jurisdictions, customers are given options for which rate schedule they are served under, and how the design of the rate is applied to their specific situation.

A clear opportunity exists to implement an optional TOU program in the immediate future for customers that could make use of off-peak energy times to reduce electricity costs, but would not burden customers who could not make use of the program. Clearly, under such an offering, customers with an economic advantage to participating in the TOU program would do so, and customers who would not benefit would remain on the existing rate schedule. This gives rise to two important perspectives:

- **System Benefits:** The implementation of a TOU rate has the opportunity to cause two beneficial system effects – peak load shifting (using the same amount of power, but more in off-peak periods rather than on-peak periods), and off-peak load building (using more power, and in particular off-peak power which can be an advantageous sale for Hydro). It is important to note that the premise of TOU rates does not hinge on load shifting – it builds on the theory that a particular profile of customer is lower cost to serve that others, due to their load timing (in a manner that is more refined than could be achieved by COS analysis and should hence see lower bills). For this reason, TOU rates can be seen as an opportunity to rectify the disadvantage that some customers (who use more power in lower cost periods) current face under a flat rate regime such as Hydro applies. However, if a customer can also shift some load to enhance the benefits of TOU, that load shift is likely to also be of benefit to all customers, not just industrials.
- **Revenue Loss:** It is acknowledged that the highest load factor customers, who use power consistently at all hours and at flat levels, would not benefit from TOU rates and would not partake in an optional program. At the same time, those customers who can participate would be expected to select this rate offering. Overall, this could lead to a revenue loss to Hydro. However, the total negative impact of this based on Hydro's 2016 TOU proposal design, would be expected to be on the order of $1.5 million/year or less for the GSL <100kV class[238] (less than 1% of rates paid by the class). Note that this impact does not yet including any economic upside such as increased export revenue or reduced costs to meet capacity peaks. As noted above, the GSL >100kV class currently pays revenues that are $20 million over costs in PCOSS18. In short, while Hydro is correct that implementing an optional TOU program may likely lead to some net revenue loss, the effect is likely to be at best a very small percentage of what the GSL >100 kV has been paying above costs for many years (compared to the above revenue:cost calculations which show GSL >100kV

[238] MIPUG/MH I-5c&d

paying \$180.5 million/\$160.6 million, or 112.3%; after \$1.5 million in net reduced revenue, this ratio would drop to 111.4%), still more than double above the accepted zone of reasonableness.

The implementation of TOU rates on an optional basis could provide a permanent benefit to some customers who have a lower-cost-than-average profile. There is no apparent downside to moving forward at the earliest opportunities, using a rate design along the lines of MIPUG/MH I-5f Attachment.

ATTACHMENT A:

QUALIFICATIONS OF MR. P. BOWMAN

PATRICK BOWMAN
PRINCIPAL & CONSULTANT

AREAS OF EXPERIENCE:

- Utility Regulation and Rates
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), University of Manitoba, 1994

PROFESSIONAL EXPERIENCE:

InterGroup Consultants Ltd. **Winnipeg, Manitoba**
1998 – Present **Research Analyst / Consultant / Principal**

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 expert 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 Manitoba Industrial Power Users Group (1998 - Present): Prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in General Rate Application and revenue requirement reviews, the Needs For and Alternatives To (NFAT) resource planning hearing, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (CentraGas) by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures, surplus energy rates and demand side management initiatives including curtailable rates and load displacement.

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 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 Nelson Hydro (2013 - Present): Development and updating of a Cost of Service model.

For the Office of the Utilities Consumer Advocate of Alberta (2016 - Present): Analysis and strategic support of depreciation matters in the Altalink Management Ltd. 2017 – 2018 General Rate Tariff Application.

For City of Chestermere (2015 - 2016): Analysis of rate proposal from Chestermere Utilities Inc. (December 2015 - February 2016).

For Yukon Energy Corporation (1998 - 2014): Provide 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 City of Swift Current (2013 - 2014): Utility system valuation approach.

For Municipal Customers of City of Calgary Water Utility (2012 - 2013): Analysis of proposed new development charges and reasonableness of water and wastewater rates (City of Chestermere, City of Airdrie, Town of Cochrane, and Town of Strathmore).

For Yukon Development Corporation (1998 - 2012): 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 Company Ltd. (2004 - 2006): Review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

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

For Yukon Energy Corporation (2005 - 2014): 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 - 2012): Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. 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): Provided 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): Provided 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, Northwest Territories**
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.

Patrick Bowman - Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009-10	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016-17	No - Negotiated Settlement
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016-17	No - Written Process only
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council

ATTACHMENT B:

OVERVIEW OF MIPUG MEMBERSHIP & CONCERNS

ATTACHMENT B: OVERVIEW OF MIPUG MEMBERSHIP AND CONCERNS

The Manitoba Industrial Power Users Group (MIPUG) has provided the following outline of the membership and concerns:

MIPUG is a membership-based 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 has 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 Hydro's 2013 Needs For and Alternatives To (NFAT) review.

MIPUG membership currently includes the following companies:

- Amsted Rail - Griffin Wheel Company, Winnipeg;
- Canadian Kraft Paper Inc., The Pas;
- Chemtrade Logistics, Brandon;
- Enbridge Pipelines Inc., Southern Manitoba;
- ERCO Worldwide, Virden;
- Gerdau Long Steel North America – Manitoba Mill, Selkirk;
- Hylife Ltd., Neepawa;
- Integra Castings (CTD Group), Winkler;
- Koch Fertilizer Canada ULC, Brandon;
- Maple Leaf Foods Inc., Brandon and Winnipeg,
- TransCanada Keystone Pipeline, Southern Manitoba; and
- Winpak Ltd., Winnipeg.

All MIPUG members are in Hydro's General Service Large classes. Even though the majority of MIPUG's load falls within the >100 kV customer class, MIPUG also includes companies who represent over half of the smaller 30-100 kV class, and a number of customers in the 0-30 kV class.

MIPUG compiled information on each of the member companies as part of a broad economic impact update in 2017, as an update to the 2005, 2008 and 2012 studies that had previously been filed with the Board.[1] Table B-1 highlights some of the contributions MIPUG member companies made to Manitoba's economy in 2015.

Table B-1: Economic Profile of MIPUG Members

	2015
Number of Member Companies	12
Number of Employees (FTE)	6,200
Direct Labour Costs	$345 million
Contract or Indirect Labour Costs	$46 million
Total Taxes	$223 million
Capital Investment in Manitoba	$6,344 million
Sales	$2,784 million
Donations and Contributions to Community	$1.6 million
Electricity Purchases	$165 million

As shown in Table B-1, MIPUG members accounted for over 6,200 direct full-time equivalent jobs. With $345 million in direct labour costs, it is estimated that the average full-time employee earned approximately $56,000 in wages. MIPUG members purchased approximately $165 million worth of electricity and contributed nearly $2.8 billion to provincial GDP; while holding more than $6.3 billion of capital investments in Manitoba.

The above impact focuses solely on direct employment of staff. A number of MIPUG companies also employ significant contract services who are entirely dependent on the MIPUG member companies (for example, forest woodlands harvesters). While this data was not updated for the 2015 inputs, at the time of the last MIPUG economic impact assessment, employment in this category shows 1,274 workers. Combined with this above, this would yield an estimated 7,500 employees.

The above values also do not include the impact of the mining sector in Manitoba, which coordinates with MIPUG via the Mining Association of Manitoba, but are not directly accounted for as individual members.

In short, the review indicates MIPUG companies (and associated companies in the GSL classes) are significant contributors to Manitoba's economy and are particularly important to some of Manitoba's larger communities outside of Winnipeg. The majority of full-time employees were 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 $2.8 billion. MIPUG members sell over 90% of the products they produce outside of Manitoba.

[1] 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. 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.

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;
- Assurance that general customer rates are reasonable within the context of long-term cost projections and provision of secure financial reserves that are appropriate, and not excessive, 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.

ATTACHMENT C:

NFAT HEARING TRANSCRIPT EXCERPTS
RE: RATING AGENCIES
MARCH 20, 2014

ATTACHMENT C: NFAT HEARING TRANSCRIPT EXCERPTS RE: RATING AGENCIES MARCH 20, 2014

Page 3073, line 25 to Page 3077, line 2

MR. BOB PETERS: All right. Let's turn, please, to page 204, also under Tab 23 at Exhibit 58-4. It's just the next page. And if we go down to the challenges, we see at the bottom of the page there's three (3) challenges listed, Mr. Schulz. And we've talked a fair bit about hydrology risk; and this is just recognition by DBRS that Manitoba Hydro faces exposure because of its hydrology risk, correct?

MR. MANFRED SCHULZ: Correct.

MR. BOB PETERS: And when we get down to the high leverage, Manitoba Hydro's leverage remains one (1) of the highest among government-owned integrated utilities in Canada, limiting its financial flexibility going forward. I read that correctly?

MR. MANFRED SCHULZ: You read that correctly. And that reinforces the point about why the equity ratio is important for us and why -- and through the eyes of the credit rating agencies, the continued vigilance on the debt-equity ratio and our equity ratio and our financials is so important for them, because this is something that has a fair amount of visibility. And coming to the point about the regulatory support, if we had a situation where we were not getting the regulatory support in order for us to continue with that, they would consider that to be a weakness for us. But thus far, the regulatory regime has been supportive of our requirements.

MR. BOB PETERS: But we know that the debt-equity ratio is going to suffer over the next -- it's going to be below target at least over the next twenty-two (22) years, according to forecast, Mr. Schulz, correct?

MR. MANFRED SCHULZ: Correct. And they're aware of that.

MR. BOB PETERS: And when they say Manitoba Hydro will have reduced financial flexibility, what does Manitoba Hydro understand that to mean?

MR. MANFRED SCHULZ: When you take on more leverage, you take on more debt. You have less ability to take on further debt, which means you know, you reach limits in saturation. So it's nothing more specific to that than that. And so the more leverage you have the -- it's just a natural consequence, the more debt that you have, the less flexibility you have.

MR. BOB PETERS: And so the additional increased costs of Keeyask and Conawapa that were announced March the 10th result in decreased financial flexibility for the Corporation?

MR. MANFRED SCHULZ: Not necessarily. I mean, there's a lot of other puts and takes to this. So, again, we're looking at this from a corporate perspective. It wouldn't move the needle, from their perspective. And keeping in mind that the credit rating agencies, and DBRS in particular, when they're looking at this, have looked at all of our financial ratios. They've looked at all of the forecasts. They're fairly close observers of the regulatory proceedings. So we actually find them to be, as the other credit ratings used to be, fairly informed in terms of the matters for not only Manitoba Hydro, but also as part of their utility analysts, all the other utilities, oil, BC Hydro you know, they're analysts; they do this as a full time job, looking at the regulatory practices. So this is a common occurrence for there to be increased capital expenditures. They're aware of it. They see the equity ratios. They see the -- you know, the investment periods. It's a natural consequence that they see the returns. And we -- they see there's been a planned outcome, and so they're not too alarmed or startled by it all. In fact, they see this as generally something that seems to be positive in the general context of what the need is for moving forward.

Page 3097, line 20 to Page 3100, line 10

THE CHAIRPERSON: No, I appreciate that, but what I'm saying is that somebody out there has bought Manitoba Hydro bond -- has bought a bond, and they say for the sake of argument, they're holding a billion dollars' worth of Manitoba Hydro bond, which is unlikely, but they -- you know, simply the sake of argument. And, so they would probably be doing their own due diligence on that obligation, I would think. Do you - do they ever talk to you, talk to Manitoba Hydro?

MR. MANFRED SCHULZ: What we're increasingly finding, having -- when we speak to our members of the syndicate, and we do talk to the brokers that we have on this, and what we're finding in the conversation is that the analysts, on behalf of the investors, tend to become -- they are becoming particularly post-economic downturn much more vigilant in terms of doing their financial analysis. They will look at the credit ratings, but they'll increasingly start to do their own work, and they'll do their own analysis when they start making decisions about whether or not they want to buy province of Manitoba paper, or Ontario paper, or so on and so forth, or high quality corporate bonds and so on. Have we spoken to them specifically? I personally have in -- in my capacity as the corporate treasurer, have had the opportunity to meet with some of the investors, and the province, when they go out and meet with the investors as well, they do that as well as part of what they do as part of their relationship. So -- and what they're finding is that one (1) of the strengths that they really like about the province of Manitoba, and what they like about Manitoba Hydro particularly, is the fact that we're building solid assets, and that's something that's seen to be very positive in their eyes. They know that there's going to be cash flow stability. They know there's going to be something coming back. It's not for funding deficits or anything. It's -- you're building an asset, and that's seen to be positive in their eyes. And what we're hearing from our conversations with our brokers and from the members of the syndicate is that's increasingly being a positive attribute towards Manitoba Hydro. In spite of the fact that we're taking on more leverage and more debt, they see that as a positive. That they see this as -- yeah, once the investment is made, there's a return, and that there's a -- that -- from that return and that stream of cash, that they can have confidence that there's going to be a return to, you know, making the interest payments as they come due, as well as the principle as it comes due. So we're seeing increasingly that utility space and the government space is increasingly being very popular, and seen to be a very confident way for these investors to move forward. And that's why, from a liquidity perspective, we tend not to have any challenges in terms of being able to access the market, because there's a lot of investors out there who want to buy the province of Manitoba and Manitoba Hydro.

Page 3104, line 13 to Page 3105, line 3

MR. MANFRED SCHULZ: […] We are undertaking large pieces of financing now. We have no reason to believe that there's going to be any interruption to the liquidity, and in fact, what we're hearing from many of the investors is that, Yeah, of course your ratio goes down through this, because you're taking on more debt as part of the investments, but what are you getting out of it, as Mr. Rainkie said, is a revenue generating asset, which is very positive for them, because they have stability cash flow. All of that reduces the risk and increases our ability to access markets, so. The long and short of this is, you know, further to the point that, you know, the hypothetical, I mean, this notion that somehow we're not self-supporting, it's a complete capital 'H' hypothetical in our minds.