Supplementary Background Papers

in Regard to the Manitoba Hydro
August 1, 2017 and April 1, 2018
Rate Increase Application

in support of

the Pre-filed Testimonies of P. Bowman and C.F. Osler/G.D. Forrest

submitted to

The Public Utilities Board of Manitoba

on behalf of

Manitoba Industrial Power Users Group

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This submission contains of the following three background papers:

- Background Paper A: Manitoba Hydro Debt Levels
- Background Paper B: Needs For and Alternatives To (NFAT) Update
- Background Paper C: Uncertainty Analysis

BACKGROUND PAPER A:

MANITOBA HYDRO DEBT LEVELS

BACKGROUND PAPER A: MANITOBA HYDRO DEBT LEVELS

The 2017 GRA sets out Manitoba Hydro's view that high debt levels are problematic for the Corporation and must be addressed in an expedited time frame compared to what had previously planned. Specifically, Hydro states that:

> "Manitoba Hydro's current and projected financial situation, absent the proposed rate increases, represents an untenable risk to both the financial sustainability of the corporation and the overall economic health of the Province of Manitoba."[1]

Manitoba Hydro has determined that to achieve financial sustainability of the Corporation, rate increases should aim to reduce the time frame for the achievement of its equity target of 25% (which it cites as its minimum target) to 10 years. Hydro recommends that this strikes an appropriate balance between what is reasonable for customers and what is necessary to ensure the long-term financial health of Manitoba Hydro.[2]

As a result, Hydro is seeking rate increases above the previously projected 3.95%/year until 2024/25 (7.9% until 2023/24 and 4.54% in 2024/25) stating these increases are no longer adequate and do not fully address the revenue requirement impact of the diminished outlook for the Company's revenue, the anticipated higher carrying costs of increased capital investments, and the necessity of restoring Manitoba Hydro's financial strength in a reasonable period of time.[3]

In reviewing the GRA materials, three major aspects of the current debt situation contradict Hydro's view:

1. **Total Level of Debt**
    a. Hydro's forecast maximum debt levels in IFF16 are below debt levels previously proposed and advocated by Hydro;
    b. Reductions in the absolute level of debt, as are being targeted by Hydro, are not typical; and
    c. Manitoba Hydro remains within its traditional and established range as a share of the Province's overall debt.
2. **Interest Cost to Ratepayers Arising from Debt Levels**
    a. The carrying costs of debt are only 14% higher (in real terms) than at the end of the last major build-out (Limestone in the 1990s) from 30 years ago;
    b. The most significant debt servicing cost pressures are not from capital investment or borrowings, but from Hydro's own shareholder; and

[1] Tab 2, page 2, Manitoba Hydro 2017/18 & 2018/19 GRA.
[2] Tab 2, page 3, Manitoba Hydro 2017/18 & 2018/19 GRA.
[3] Tab 2, page 9, Manitoba Hydro 2017/18 & 2018/19 GRA.

c. Hydro's exposure to interest rate increases is the lowest it has been in many years.

3. **Need for Manitoba Hydro to Rely on More Debt Financing than Other Crown utilities.**

Each of these items are addressed below.

The key to understanding Hydro's current financial situation with respect to debt and interest costs is recognizing the steps of major capital development in Hydro's long history, and where Hydro currently resides in this cycle. There is an established pattern where Hydro invests in new major capital project development followed by periods of retrenching and restoring financial strength before the next build out. During the periods of restoration, when the new capital development is in operation and providing valuable service, the improvements occur not through absolute debt reduction per se, but through cash financing of ongoing normal capital reinvestment and the building of reserves.

Hydro's current financial plan does not following this same approach. Current attempts to restore financial strength while still investing in capital development, or during the most challenging initial years of service, run contrary to the overall investment approach noted above.

1. TOTAL LEVEL OF DEBT:

a. Projected maximum debt levels are below levels previously proposed and advocated by Hydro:

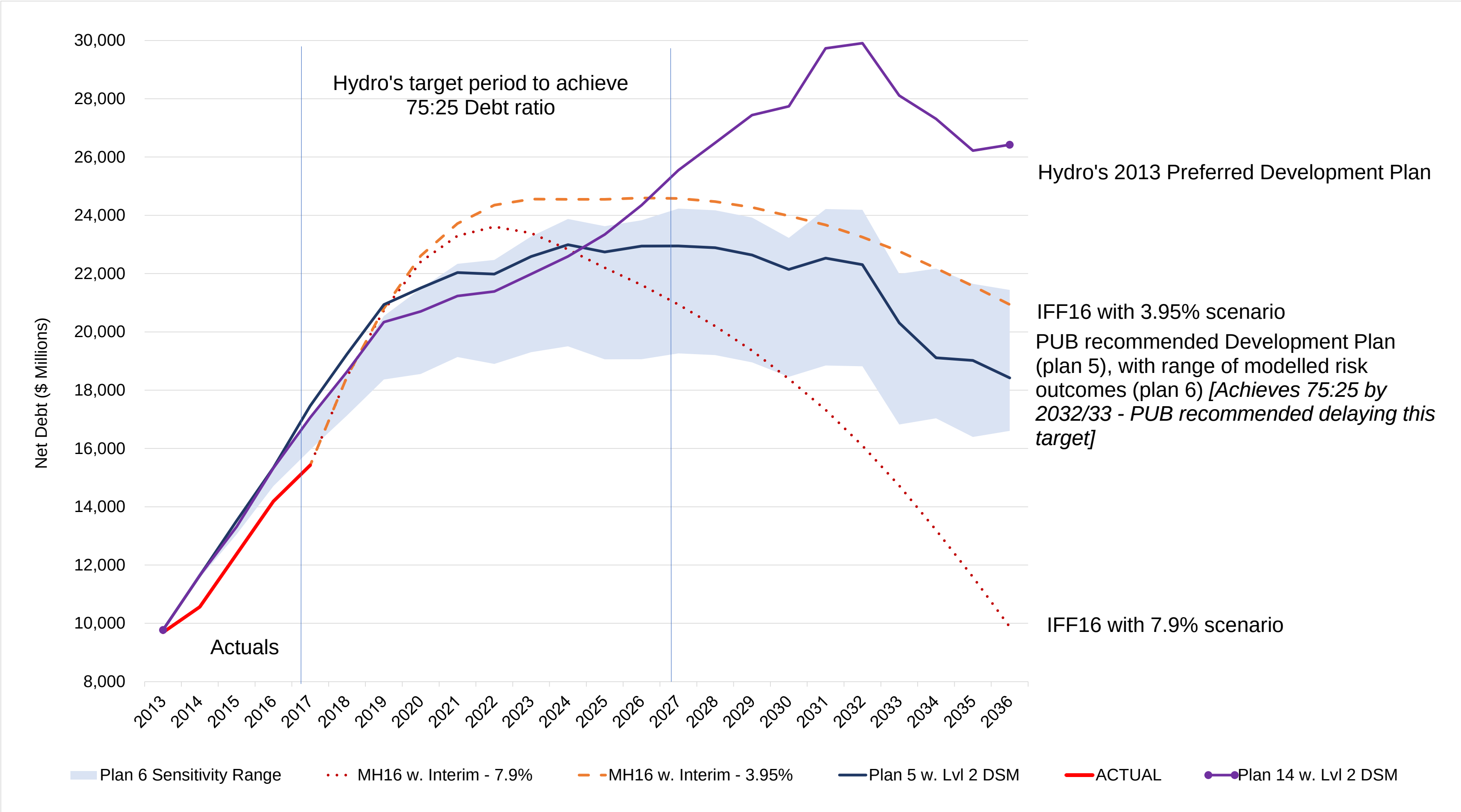
The absolute debt levels reached in IFF16 (with 3.95% rate increases) peak at $25.2 billion in 2027/28.[4] Hydro cites this type of peak value as a central basis for their concern. However, previously Hydro had advocated for development plans that peaked at $30.0 billion[5] in debt. The absolute level of debt is lower, not higher, in today's forecasts than Hydro's preferred plans in 2013.

Figure A-1 below highlights the comparison of the relevant scenarios.

[4] PUB/MH II-34 Attachment 2.

[5] The Needs For and Alternatives To (NFAT) Review, Manitoba Hydro Exhibit MH-104-12-4, pdf page 3, the Preferred Development Plan (14) peak debt in 2032 including estimated current portion of LTD.

Figure A-1: Manitoba Hydro Net Debt under NFAT Scenarios and Updated IFF Scenarios at 3.95% and 7.9[6]



[6] 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 MPUIG/MH-I-2g.

Figure A-1 above includes four data sets:

- **NFAT – PUB Recommended Plan as Approved by the Minister (blue):** The blue line and shading represents the NFAT scenarios that were reviewed and recommended by the PUB to proceed (further discussed in Background Paper B), including both the reference forecast for plan 5 (the blue line), and the range of considered risk scenarios for plan 6 (the blue shaded area), which were in large part equivalent plans (at least for the purposes used in this figure).[7]
- **NFAT – Hydro's Preferred Development Plan (purple):** The purple line in the preceding figure represents the required net debt forecast for Hydro's preferred development plan from NFAT (including Conawapa).
- **IFF16 Update with Interim and 3.95% rate increases scenario (orange):** The IFF16 scenario focused on Hydro's net debt with 3.95% rate increases (same rate increases as IFF15).
- **IFF16 Update with Interim and 7.9% rate increases scenario (red):** The net debt levels with Hydro's proposed rate changes are shown in red.

Reviewing Figure A-1 shows that debt levels since the NFAT proceeding (2013) to today (2017) remain well below the levels forecast at the time of the NFAT proceeding. This is consistent with delayed in-service dates for the major projects such as Keeyask. By the time of Keeyask's in-service (2022/23) the net debt will be somewhat higher than expected at the NFAT, consistent with the increases to the project's capital costs.

Maximum debt under either IFF scenario (3.95% versus 7.9%) is in the range of mid-$20 billion ($25.1 billion for 3.95%, $23.6 billion for 7.9%), which is above the $23 billion expected under the ultimately recommended plans 5/6, but well below the $30 billion expected under Hydro's then-Preferred Development Plan.

b. Reductions in the absolute level of debt, as are being targeted by Hydro, are not typical

Hydro has adopted a 7.9%/year rate increase pathway followed by 2%/year increases. Hydro's rationale for this proposal is tied to increasing the equity ratio, and reducing Hydro's overall debt levels.

The effect of Hydro's rate proposal on its equity ratio is clear, as shown in reproduced Figure A-2 below.

[7] As reviewed in **Background Paper B**, plans 5 and 6 differed only on the assumptions regarding the export arrangement with Wisconsin Public Service. Although plan 5 represents the closest scenario to what was recommended by the PUB as it has now unfolded, the NFAT hearing did not provide a full dataset including risk scenarios for plan 5, but did provide this data for plan 6. As a result, the above figure uses a mixture of the plan 5 data for reference conditions and the plan 6 data for risk scenarios. If plan 5 data for risk scenarios had been made available, it is understood from reviewing the economic analysis that if anything the size of the blue shaded area would be reduced due to the largest proportion of export sales locked in under this plan.

Figure A-2: Manitoba Hydro's Equity Ratio from 1962 - 2034 Updated for IFF16 Update with Interim[8]

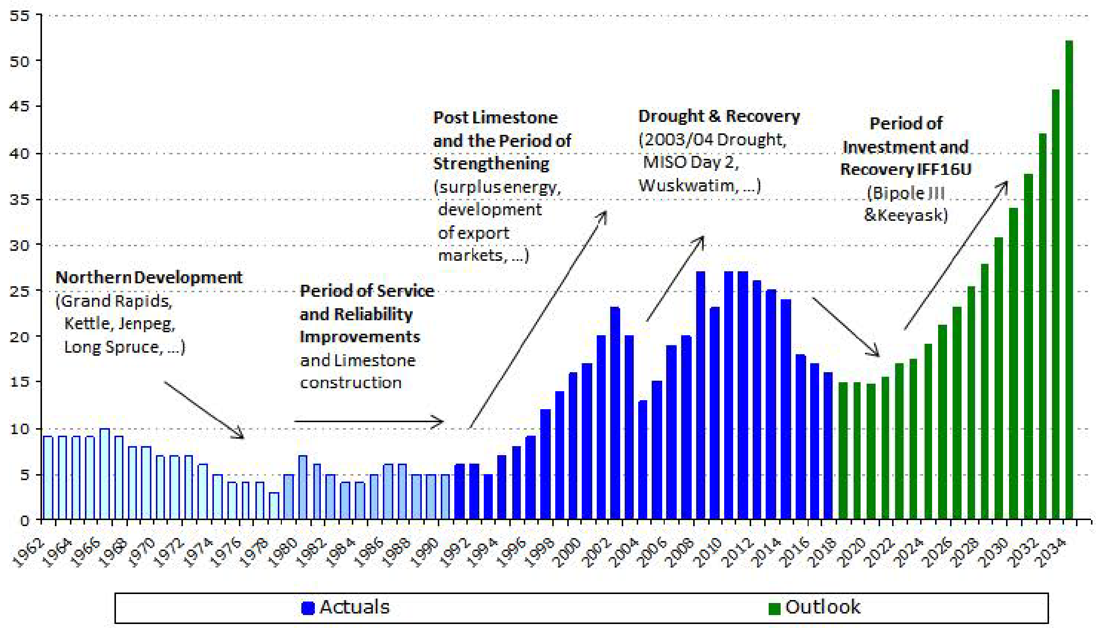
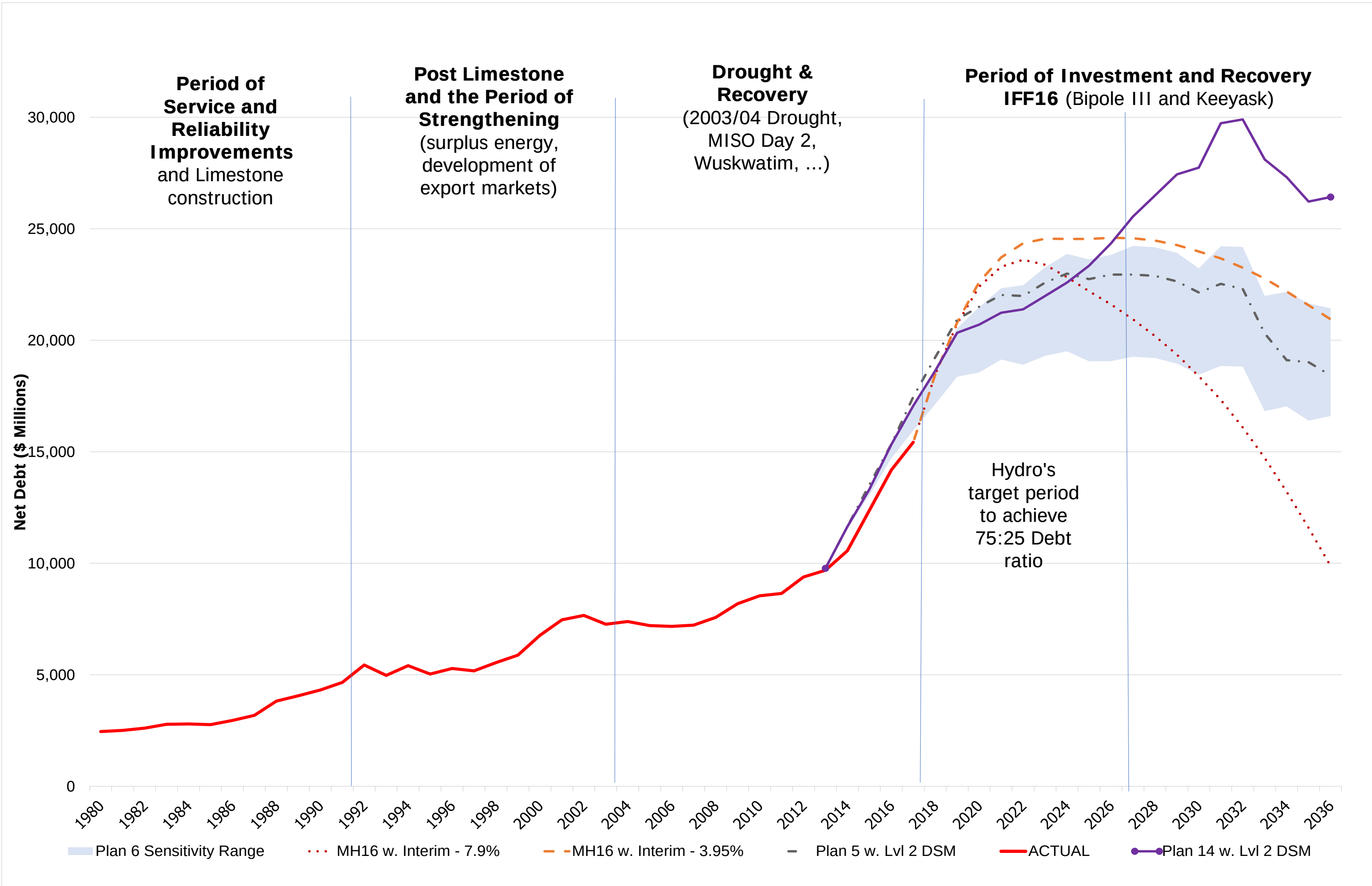


Figure A-2 (produced by Hydro in MIPUG/MH I-2h-I) highlights the steps of major capital development and patterns of investment as they affect the ability to build retained earnings as a percentage of assets (i.e., reducing the equity ratio). Specifically, this figure highlights the reduced retained earnings ratio (and corresponding rise in long-term debt and the debt ratio) with the northern development of the late 1960s/1970s. A period of relative stability followed which permitted increasing retained earnings percentages as Limestone and the other northern assets begin to provide the benefits of their stable cost, relatively inflation-protected power supplies through the 1990s and 2000s (with the notable effect of the 2004 drought evident). The retained earnings ratio continue to build until a new period of debt financing associated with the modern period of capital developments through 2024.

The limitation of Figure A-2 above is its failure to portray how the Hydro financial targets over this period have permitted growth in the retained earnings ratio between periods of major development without absolute debt reduction (which is addressed in the Figure A-3 below) Hydro's current proposal differs in this respect. Figure A-3 focuses on the same trend information, looking at the absolute levels of debt over this period.[9]

[8] MIPUG/MH I-2h-I, page 9 of 14, Manitoba Hydro 2017/18 & 2018/19 GRA.
[9] Due to data limitations, the absolute level of debt is only available back to 1980, not the full period to 1962.

Figure A-3: Manitoba Hydro Net Debt under NFAT Scenarios and Updated IFF Scenarios at 3.95% and 7.9%[10]



[10] 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.

Figure A-3 above shows the data since 1980 (with forecasts to 2036) for Hydro's net debt levels. The same scenarios are modelled as seen in Figure A-1 earlier in this document, namely NFAT recommended (blue), Hydro proposed NFAT plan (purple), actuals with Hydro's IFF16 forecast (red), and the alternative IFF16 based on 3.95% increases (orange).

Figure A-3 highlights that Hydro's longstanding practice does not typically involve reductions in the net debt levels. The level of debt for actual years captured in Figure A-3 is provided in Table A-1 below:

Table A-1: Year to Year Changes in the Total Long Term Debt Balance ($ Millions) from March 31, 1980 to March 31, 2017[11]

Fiscal Year	LTD	Current Portion	Total LTD	Change
1980	2,404.4	48.6	2,453.0	
1981	2,439.8	67.2	2,507.0	54.0
1982	2,529.3	75.4	2,604.7	97.7
1983	2,608.0	172.8	2,780.8	176.1
1984	2,670.0	122.9	2,792.9	12.1
1985	2,553.7	210.5	2,764.2	(28.8)
1986	2,875.0	78.6	2,953.6	189.4
1987	3,027.3	153.1	3,180.4	226.8
1988	3,591.6	229.7	3,821.3	641.0
1989	3,746.2	314.3	4,060.5	239.2
1990	3,986.0	331.8	4,317.8	257.3
1991	4,341.7	314.6	4,656.3	338.5
1992	4,560.7	880.1	5,440.8	784.5
1993	4,809.3	162.1	4,971.4	(469.4)
1994	5,087.5	318.8	5,406.3	434.9
1995	4,938.6	96.5	5,035.1	(371.2)
1996	4,766.8	517.6	5,284.4	249.3
1997	4,246.6	928.2	5,174.8	(109.6)
1998	5,547.9	-	5,547.9	373.1
1999	5,883.0	-	5,883.0	335.1
2000	6,611.0	159.0	6,770.0	887.0
2001	6,968.0	496.0	7,464.0	694.0
2002	7,123.0	538.0	7,661.0	197.0
2003	6,925.0	343.0	7,268.0	(393.0)
2004	7,114.0	276.0	7,390.0	122.0
2005	7,048.0	156.0	7,204.0	(186.0)
2006	7,051.0	118.0	7,169.0	(35.0)
2007	6,822.0	405.0	7,227.0	58.0
2008	7,218.0	353.0	7,571.0	344.0
2009	7,668.0	519.0	8,187.0	616.0
2010	8,228.0	310.0	8,538.0	351.0
2011	8,617.0	30.0	8,647.0	109.0
2012	9,101.0	281.0	9,382.0	735.0
2013	9,329.0	656.0	9,985.0	603.0
2014	10,460.0	408.0	10,868.0	883.0
2015	12,303.0	377.0	12,680.0	1,812.0
2016	14,201.0	326.0	14,527.0	1,847.0
2017	16,102.0	336.0	16,438.0	1,911.0

[11] MIPUG/MH I-2g, page 3 of 3, Manitoba Hydro 2017/18 & 2018/19 GRA.

While there have been some intermittent instances of absolute debt reduction (7 instances in the 37 year history reproduced in Table A-1), these were typically intermixed with debt increases in adjoining years, such that there was no attempt at multi-year sustained debt reduction.

Reductions in the absolute level of debt for Manitoba Hydro are rare for three reasons:

i. Utilities are capital intensive and offer a service intended to be perpetual. Ongoing reinvestment is to be expected.

ii. Debt financing is the lowest cost source of capital to finance large assets. Manitoba Hydro cannot raise equity capital through the sale of shares, but even if it could this would be far more costly than achieving the same funds through borrowing. The citizens of Manitoba save themselves considerable financing costs by using their own guarantee (through the Government of Manitoba) rather than an investor's equity.

iii. For Hydro, reductions in the absolute level of debt cannot be achieved without generating excess cash from the ratepayers of Manitoba, through higher rates than would otherwise be required. Low rates are like a financial reserve – this reserve can be accessed by increasing rates if adverse conditions warrant. But actually tapping this reserve comes at a price for the economic performance of the overall provincial economy. KPMG cites the same concept, noting that the potential for future rate increases functions as a form of financial strength, as shown in their definition of self-supporting, specifically that "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"[12] (emphasis in original). Despite the presence of this form of financial reserves, it is an adverse trade-off to use this reservoir before or unless needed.

c. Manitoba Hydro remains within its traditional and established range as a share of the Province's overall debt

Hydro claims that its share of Manitoba Government borrowings will grow as a result of the current capital build-out, citing that by 2017, Hydro's share of the Provincial government debt will be 39%.[13] KPMG cites the potential for this percentage to grow to "the mid-40s by 2019/20, depending on the rate of increase of provincial tax supported debt."

Boston Consulting Group (BCG) provided further context in the below figure, showing Manitoba Hydro's net debt at mid-40 percent is in no way unprecedented, and in fact not only consistent in pattern with previous periods of development, but well below levels previously seen.

[12] Appendix 4.1, page 7, Manitoba Hydro 2017/18 & 2018/19 GRA.
[13] Manitoba Hydro 2017 Debt Management Strategy, page 5; filed as Appendix 3.5 in Manitoba Hydro 2017/18 & 2018/19 GRA.

Figure A-4: Manitoba Hydro Debt to Manitoba Provincial Debt Comparison ($2015 billion)[14]

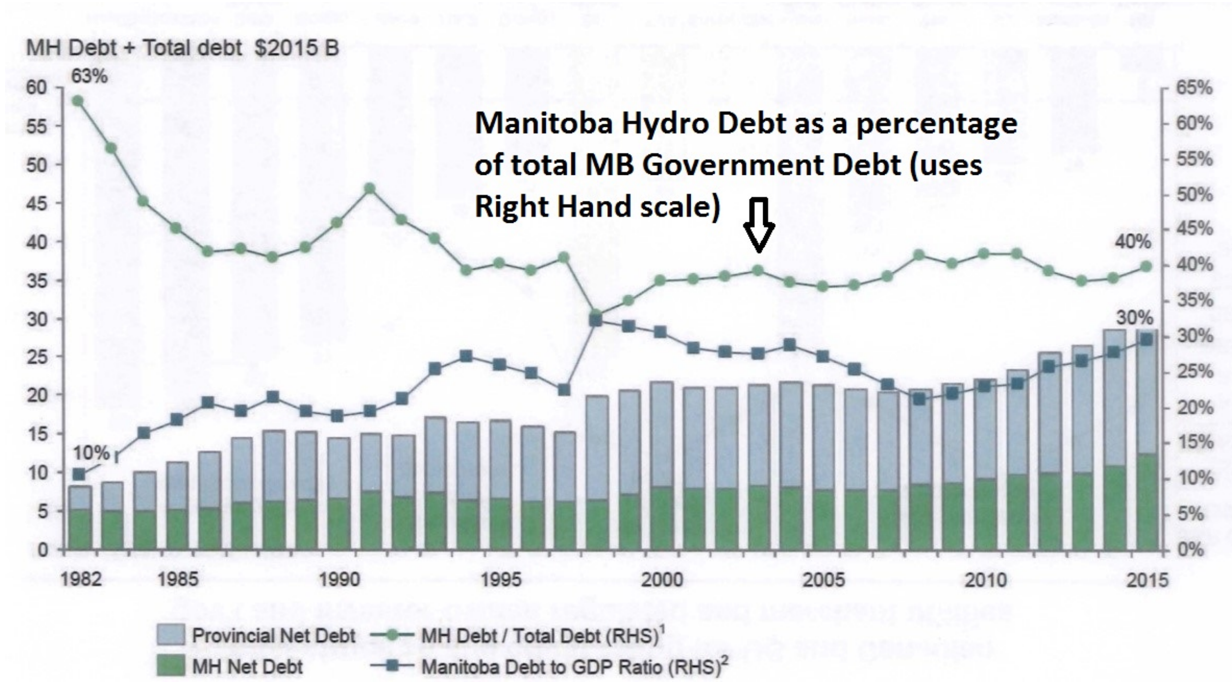


Figure A-4 above is taken from the work of BCG showing on the upper green dotted line the ratio of Hydro's net debt as a percentage of the Provincial Government total borrowed and guaranteed debt. As shown, Hydro's share of total provincial borrowings was a very high percentage in the 1980s at over 60% of the total, as Hydro was coming out of the major 1970s capital developments (e.g., Long Spruce, Jenpeg, Lake Winnipeg Regulation and the Churchill River Diversion). The debt percentage declined through the 1980s, peaking again once Limestone was being brought into service in the early 1990s – this time at approximately 50-55% of the provincial total. Increases in the government's net debt (i.e. debt borrowed for its own needs) shown by the grey/blue bars led to declines in this ratio through the mid-1990s, a period where Hydro was doing relatively smaller capital additions and borrowing of its own.

No numerical forecasts appear to have been provided for forecast debt percentages, though BCG provided forecast graphs show that even to 2023, Manitoba Hydro net debt and the province's own share of the debt remain approximately equal at about $25 billion each, as shown in the height of the bars in Figure A-5.

[14] PUB-MFR-72 Attachment, page 27 of 615, Manitoba Hydro 2017/18 & 2018/19 GRA.

Figure A-5: Manitoba Hydro and Manitoba Provincial Debt Comparison to MB GDP[15]

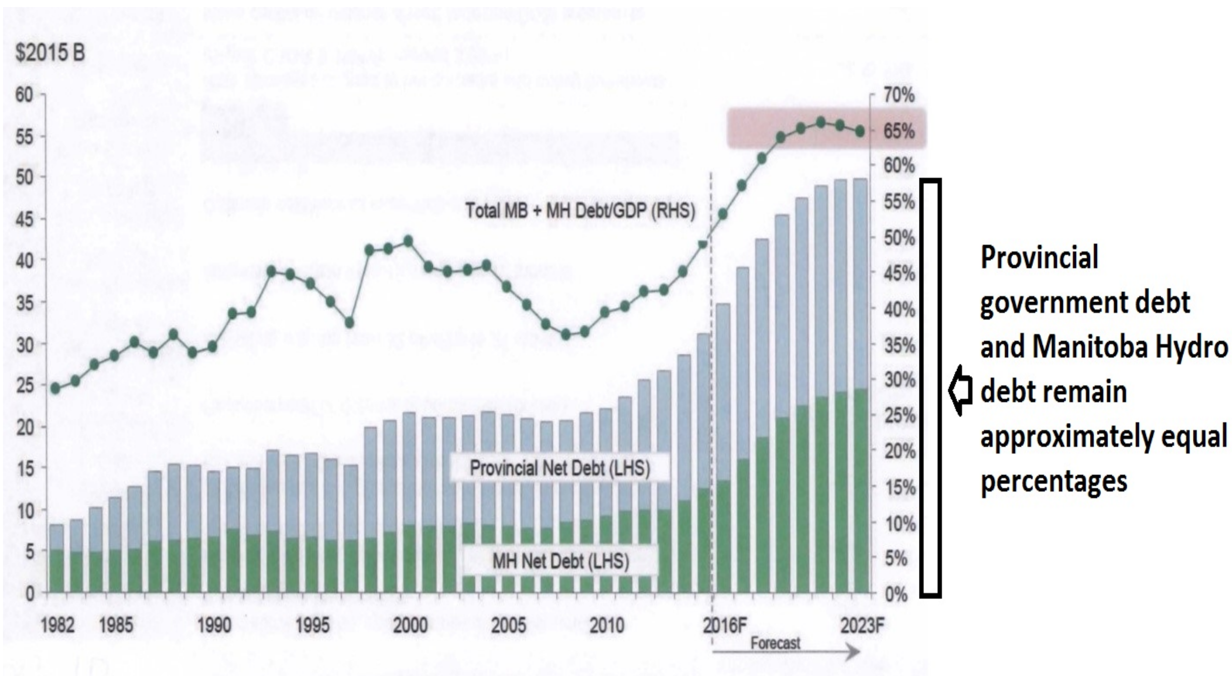


Figure A-5 highlights in the green bars (Manitoba Hydro) and grey/blue bars (Province of Manitoba) graphed against the Left-Hand Scale (LHS, in billions) at approximately an equal net borrowing through 2023, which remains below the percentage share for Hydro experienced coming out of previous capital development periods after Long Spruce (early 1980s) and Limestone (early 1990s).

2. INTEREST COST TO RATEPAYERS ARISING FROM DEBT LEVELS

a. Carrying costs of debt are only 14% higher in real terms than at the end of the last major build-out (Limestone) from 30 years ago:

The absolute debt levels in 2023/24 (IFF16 Update with Interim, with 3.95% increases) in relation to domestic load are notably quite high compared to past history, but the key effect on Hydro's finances are not the absolute level of debt per se, but the carrying costs of the debt. Under this metric, normal external debt costs are not exceedingly high today compared to the capability of the system.

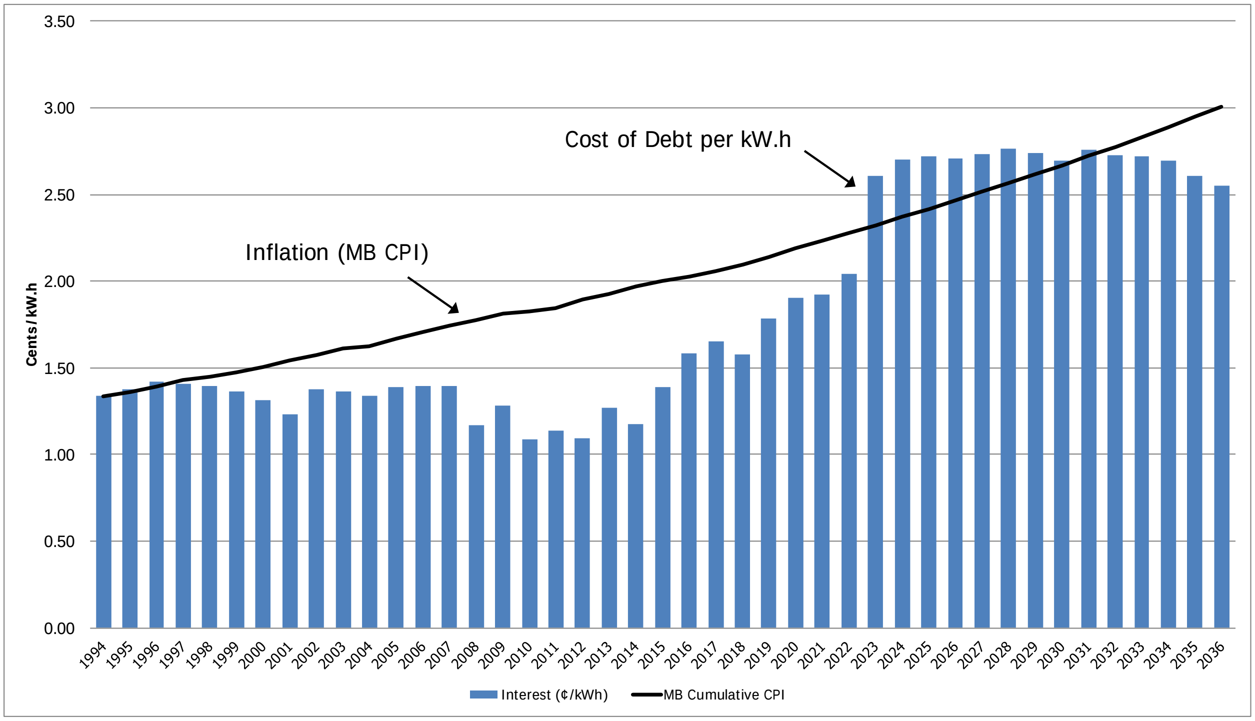
The net debt in 2023/24 is large in absolute terms. However, there are two other material changes offsetting this increase. First, Hydro's external debt servicing costs have dropped by 60% over this time (from the low 9%'s to the high 3%'s). Second, current outstanding debt is

[15] PUB-MFR-72 Attachment, page 309 of 615, Manitoba Hydro 2017/18 & 2018/19 GRA.

financing a group of assets that are serving a much larger magnitude of non-domestic sales than was the case in 1994.[16]

For a full comparison, it is important to look at the costs of carrying debt (interest expense), compared to the full capability of the system. Looking at the situation with sustained 3.95% increases, the real carrying costs of Hydro's debt in the worst year of IFF16 (2024) are about 14% higher than the carrying costs of debt from the period immediately after the last major build-out of Limestone, as shown in Figure A-6.

Figure A-6: Manitoba Hydro Cost of Debt (in cents/kW.h) - Comparison to Manitoba CPI - MH16 w. Interim Update and MH15 Rate Increases 1994 to 2036[17]



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[16] Per PUB MFR-25, the 2024 export sales at average water could exceed 12 TW.h. In the years following Limestone export sales ranged from 3 TW.h (low water year) to almost 10 TW.h (high water year) per Appendix 56 Attachment 5.1 from the 2010 GRA, page 5.

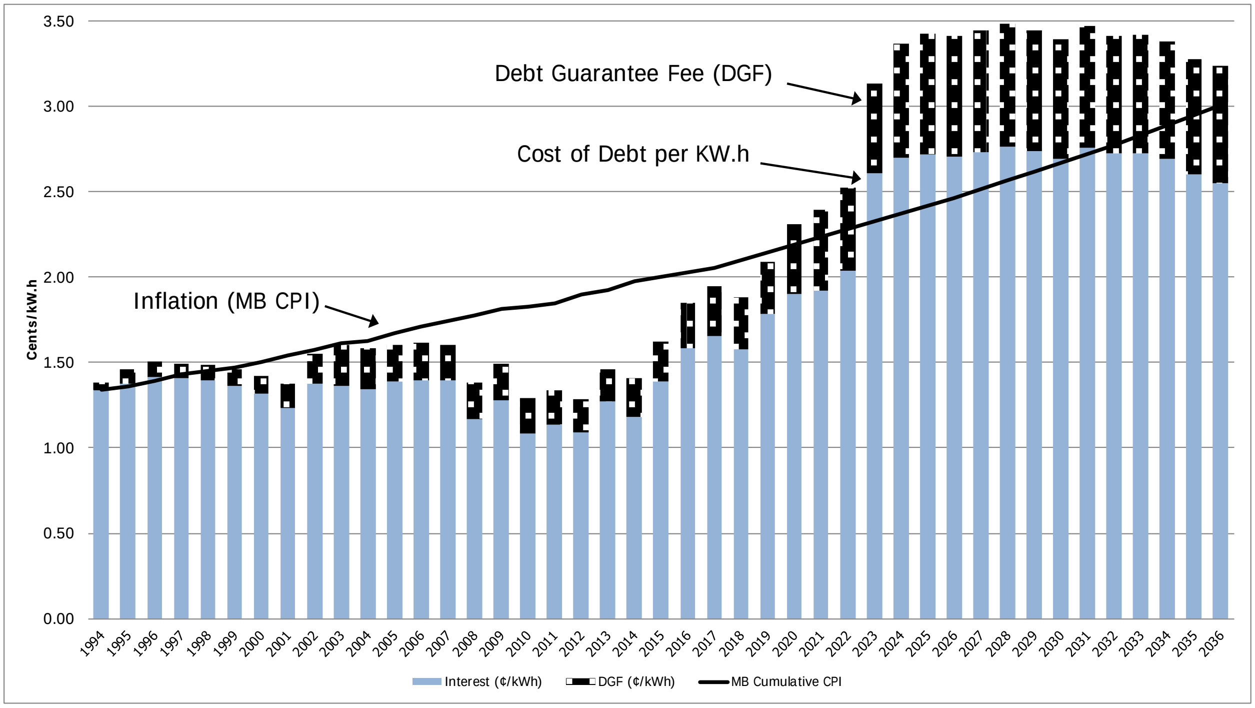
[17] Hydraulic Generated Power (denominator): MIPUG MFR 9 from 2017/18 & 2018/19 GRA and MIPUG/MH I-9 from 2015 GRA. Manitoba CPI provided in PUB-MFR-53, Economic Outlook 2017 – 2038, page 17. Cost of Debt from Finance Expense Schedules ((1992 – 1995 from 1994 & 1996 Minimum Filing Requirements Question A-1: Financial Statements; 1996 – 1998 from 2002 Status Update Review, PUB/MH I-8; 1999 – 2003 from Hydro 2008/09 GRA, PUB/MH I-43; 2004 – 2012 from Hydro 2012/13 & 2013/14 GRA, PUB/MH I-66(REVISED); 2013-2014 from 2015/16 GRA, PUB/MH I-26a; 2015-2016 and forecast from PUB-MFR-55 and COALITION I-96a-d) less Provincial Debt Guarantee less capitalized Interest. Provincial Debt Guarantee Fee from Finance Expense Schedules is deducted less assumed capitalized interest associated with the DGF calculated based on weighting of DGF as a percentage of total debt before capitalization. To approximate DGF fee for MH16 with Interim at IFF15 rate increases in forecast years 2018/19 – 2035/56 - DGF from Finance Expense Schedules (less proportion for capitalized interest) used plus weighted difference in added Finance Expense due to lower rate increases (Finance Expense from Projected Operating Statement in Appendix 3.8 for Hydro proposed MH16 with Interim Update less PUB/MH I-34 Attachment 2 for MH16 with Interim update and MH15 rate increases) as proportion of DGF to total gross interest (also from Finance Expense Schedule).

Figure A-6 above highlights that the interest component of Hydro's cost structure (in relation to total hydraulically generated power) in 2024 is 2.70 ¢/kW.h compared to 1.34 ¢/kW.h in 1994. Figure A-1 also shows Manitoba CPI inflation (represented in the figure by the black line). In real terms, the cost of interest in rates in 2024 would be 2.40 ¢/kW.h if interest remained at the 1994 level, versus the 2.70 ¢/kW.h now forecast if a 3.95% rate increase scenario is adopted. This is a 14% increase over 30 years in the worst single year (2024). Outside of the worst year, the real interest cost in rates for the current development remains higher than 1994 levels (adjusted for inflation) for approximately 7 years in the forecast, from 2023 to 2029.

b. Most significant debt servicing cost pressures are not from capital investment or borrowings, but from Hydro's own shareholder:

While the unit cost of servicing Hydro's debt, in real terms, remains only 14% above the period coming out of the last major build out (Limestone in the early 1990s), the costs associated with the Government guarantee of this debt has increased 384% in real terms (almost 16 times before inflation), as shown by the dark bars in the Figure A-7 below.

Figure A-7: Manitoba Hydro Cost of Debt (Interest Payments & Debt Guarantee Fee) Comparison to MB CPI (cents/kW.h) MH16 w. Interim Update and MH15 Rate Increases – 1994 to 2036[18]



Compared to interest costs, which increased by 0.30 ¢/kW.h in real terms between 1994 and 2024, the real increase to the cost of Debt Guarantee Fees is 0.60 ¢/kW.h. Debt Guarantee Fees made up less than 6% of the total debt cost in 1994, but by 2024 will be 21% of total debt.

The pattern of gradual but delayed increases in Debt Guarantee Fees following Limestone has a sensible rationale, in that the fees were kept low for a number of years while the project was being brought into rates and overcoming the most challenging years of its economic profile (the first decade or so after first power was produced). These fees were only raised once Hydro had begun to see significant benefits from the new projects and progress had been made towards

[18] Hydraulic Generated Power (denominator)**:** MIPUG MFR 9 from 2017/18 & 2018/19 GRA and MIPUG/MH I-9 from 2015 GRA. Manitoba CPI provided in PUB-MFR-53, Economic Outlook 2017 – 2038, page 17. Cost of Debt from Finance Expense Schedules ((1992 – 1995 from 1994 & 1996 Minimum Filing Requirements Question A-1: Financial Statements; 1996 – 1998 from 2002 Status Update Review, PUB/MH I-8; 1999 – 2003 from Hydro 2008/09 GRA, PUB/MH I-43; 2004 – 2012 from Hydro 2012/13 & 2013/14 GRA, PUB/MH I-66(REVISED); 2013-2014 from 2015/16 GRA, PUB/MH I-26a; 2015-2016 and forecast from PUB-MFR-55 and COALITION I-96a-d) less Provincial Debt Guarantee less capitalized Interest. Provincial Debt Guarantee Fee from Finance Expense Schedules is deducted less assumed capitalized interest associated with the DGF calculated based on weighting of DGF as a percentage of total debt before capitalization. To approximate DGF fee for MH16 with Interim at IFF15 rate increases in forecast years 2018/19 – 2035/56 - DGF from Finance Expense Schedules (less proportion for capitalized interest) used plus weighted difference in added Finance Expense due to lower rate increases (Finance Expense from Projected Operating Statement in Appendix 3.8 for Hydro proposed MH16 with Interim Update less PUB/MH I-34 Attachment 2 for MH16 with Interim update and MH15 rate increases) as proportion of DGF to total gross interest (also from Finance Expense Schedule).

achieving the established financial targets. No similar pattern is being proposed today for Debt Guarantee Fee staging with respect to the new developments, and it is this pressure that has the most acute debt-related effect on rates.

While the Debt Guarantee Fees are clearly a component of Hydro's costs, the importance of tracking the Guarantee Fee impacts is highlighted by Hydro's current emphasis on protecting the Government of Manitoba's credit costs. No evidence has been provided to suggest that the guarantee fee provided from 1994 to today has, in any way, led to offsetting costs for the province. It is also not clear that any Hydro-related debt pressures today or in future will lead to costs to the Province that exceed the compensation provided by this fee. As such, a valid concern is that "protecting" Hydro's shareholder by significantly advancing material debt repayment is not of the same imperative nature as portrayed by Hydro.

c. Hydro's exposure to interest rate increases is the lowest it has been in many years.

Hydro continues to fund new project spending largely through issuance of long-term debt. However, as of IFF16, Hydro faces only $14 billion in new debt to be borrowed in the first 10 years of the forecast. While this is substantial, it is the lowest 10 year debt requirement projection in any IFF since before 2010. The largest projected future borrowing requirements were seen in IFF12 and IFF13 when $21 billion and $22.5 billion respectively were projected to be required in the first 10 years of the forecast.[19]

It is expected that interest rate risk and uncertainty associated with these borrowing projections would be at its highest when borrowings were (i.e. in the early 2012 and 2013 IFFs). As more of this debt is locked in at known rates, interest rate risk and associated uncertainty will see continual decreases.

A good measure of the risks posed by interest rates can be seen looking to Hydro's risk register produced as part of each year's Financial Forecast process. The risk register from external factors over the past five IFFs is summarized in Table A-2 below.

[19] MIPUG/MH I-7a-f, Figure 1, Manitoba Hydro 2017/18 & 2018/19 GRA.

Table A-2: Risk Register - Key Variable Sensitivity - Impact to Retained Earnings IFF Comparison[20]

	IFF16 Update w Interim	IFF15	IFF14	IFF13	IFF12
Target Year 7	**2022/23**	**2021/22**	**2020/21**	**2019/20**	**2018/19**
Retained Earnings ($millions)	$4,557	$2,677	2,518	$2,502	$2,376
Low Domestic Load Growth	(133)	13	(24)	(64)	n/a
High Domestic Load Growth	128	19	54	n/a	102
+1% interest rates	(248)	(405)	(423)	(299)	(233)
-1% interest rates	233	390	398	286	136
US$ down $0.10	(16)	(19)	(3)	23	(59)
US$ up $0.10	18	22	3	(23)	57
Low Export Prices	(117)	(315)	(304)	(143)	(160)
High Export Prices	322	397	245	119	159
5 Year Drought (starting in year 3)	(1,175)	(1,857)	(1,711)	(1,583)	(1,553)

Table A-2 shows a consistent scenario analysis of projections through the 7th year of the respective IFFs. In each case, the effect shown is the cumulative impact on retained earnings should a given condition arise. For reference, forecast retained earnings as per the respective IFF in the forecast year is shown. The specific example of higher interest rates (+1%) is shown in the third row, indicating that for IFF16 the cumulative risk to retained earnings associated with a material 1% rise in interest rates compared to Hydro's baseline forecast (which already includes a notable assumed rise in rates) is $248 million over the 7 years. As of IFF15, the 7 year risk associated with a 1% interest rate rise led to $405 million in negative impact. IFF16 is the lowest 7 year interest rate risk since IFF12 (note that for IFF12, the 7 year scenario only extended to 2018/19, before a significant part of the capital investment would have yet occurred).

Table A-2 also highlights that water flows are still the biggest risk facing Hydro ($1.175 billion), but this risk is also significantly decreased compared to past periods ($1.553 to $1.857 billion) due to other factors, such as lower assumed export prices.

A separate analysis of the evolution of integrated risk (including interest rates, export prices and water flows) is provided in the uncertainty analysis in Tab 4 of Hydro's filing (and discussed in Background Paper C). That analysis shows box-and-whisker plots that portray the P5, P20, P50, P80 and P95 level, with the extreme representing the 5th percentile (19 times out of 20 results will be higher than this value) and the 95th percentile (19 times out of 20 results will be

[20] IFF16 Update with Interim rate from PUB/MH I-45; IFF15 from 2016/17 Interim Rate Proceeding, Attachment 1, pg. 27; IFF14 from 2015/16 GRA, Appendix 3.3, pg. 22; IFF13 from 2014/15 Interim Rates Proceeding, Attachment 1, pg. 16; IFF12 from Needs For and Alternatives To (NFAT) Proceeding, Appendix A, pg. 17.

lower than this value). The confidence interval between these values (90%) gives a representation of how much uncertainty is inherently being driven by the 3 factors.

- At the time of IFF15, the 90% confidence interval for net income as of 2021/22 was approximately $1 billion (5th percentile at approximately -$400 million, 95th at approximately +$600 million).[21]
- With IFF16 updated, the same confidence interval at 2021/22 is now approximately $600 million (5th percentile at approximately -$50 million, 95th at approximately +$550 million).[22]

This emphasizes the significant degree by which the risk profile has narrowed through the key years of the IFF.

3. NEED FOR MANITOBA HYDRO TO RELY ON MORE DEBT FINANCING THAN OTHER CROWN UTILITIES

The updated KPMG report on Hydro's Financial Targets (Appendix 4.5) cites that Manitoba Hydro has among the highest base of assets and debt per customer compared to other Crown utilities, reproduced in Table A-3 below.

Table A-3: Overview of Utility Asset and Net Debt Information per Capita, 2016/2017[23]

Overview of Utility Asset and Debt Information Per Capita

($CDN)	Provincially-Owned Utility	Utility Net Debt Per Capita	Utility Assets Per Capita	Net Debt/ Assets
Manitoba	Manitoba Hydro	11,981	16,947	70.7%
B.C.	B.C. Hydro	4,204	6,711	62.6%
Quebec	Hydro Quebec	5,365	9,028	59.4%
Newfoundland	Nalcor Energy	12,149	26,527	45.8%
New Brunswick	NB Power	6,475	9,207	70.3%

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2017.
2. B.C. Hydro Annual Report for the year ended March 31, 2017.
3. Hydro-Quebec Annual Report for the year ended December 31, 2016.
4. Nalcor Annual Report for the year ended December 31, 2016.
5. New Brunswick Power Annual Report for the year ended March 31, 2017.
6. Statistics Canada

[21] Appendix 4.2, Figure 4-2, Manitoba Hydro 2017/18 & 2018/19 GRA.
[22] MIPUG/MH I-1a, page 5 of 7 – in each case the 3.95% rate increase scenario is used for consistency.
[23] Appendix 4.5 – Updated Financial Target Review Report by KPMG, Figure 5.3, page 58, Manitoba Hydro 2017/18 & 2018/19 GRA.

This KPMG report fails to fairly portray the electrical power sector in the respective provinces. For example, in each other province noted other than Manitoba, there are additional non-Crown power utilities that have responsibility for portions of the generation or distribution systems (e.g., FortisBC, Newfoundland Power, etc.). As a result, Per Capita measures will be misleading, since this additional power sector debt is not included. In comparison, in Manitoba the debt and assets of Manitoba Hydro represent basically 100% of the utility investment. As the table fails to fully portray the costs to which each respective provincial utility ratepayer is exposed, the results can be misleading.

In addition, for many of the jurisdictions, major components of the power supply system are not represented appropriately by measuring the utility debt and/or assets, as follows:

- **Independent Power Producers (IPPs):** In examples such as BC Hydro, government policy has led to significant portions of the power supply being purchased from independent parties who developed generation entirely based on the premise of supplying this generation to BC Hydro. While these assets are 100% committed to BC Hydro utility supply, and BC Hydro's rates must recover the costs associated with these facilities, they would not be recorded as BC Hydro assets or debt in the BC Hydro statements. The 2017 BC Hydro Annual Report[24] notes that over 13.6 TW.h was purchased from IPPs, compared to 48.5 TW.h generated from BC Hydro's own sources. It is also important to note that the cost of IPP power is much higher than BC Hydro's own supplies – averaging 8.9 ¢/kW.h in 2017.
- **Generation Station Cost Profile:** The assets developed for power generation by Manitoba Hydro are capital-intensive. This means they are represented by large amounts of investment, and debt. However, over time the debt will be serviced in part from the fact that these generation stations are atypically long-lived (hydro at up to 140 years has a much longer life than thermal stations), have low operating costs, and basically no fuel costs, and as such are highly inflation protected. Other forms of generation, such as coal or natural gas, and other renewable resources such as wind, solar or biomass, can in certain instances be competitive to new hydro on a cost/unit basis over specified time horizons. However the cost profiles of these sources typically includes much less capital investment and debt at the outset, offset by substantial fuel costs or much shorter lives, or both. As a result, a higher debt complement is to be expected for a utility that uses predominantly self-owned hydraulic generation.

For this reason, it is to be expected that Manitoba Hydro has a larger component of assets and debt than the other Crown utilities cited.

[24] British Columbia Hydro and Power Authority, 2016/17 Annual Service Plan Report, Page 24. Available online: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2016-17-annual-service-plan-report.pdf Purchases from Independent Power Producers $88.90/MWh for 2017, $85.82/MWh for 2016.

BACKGROUND PAPER B:

NEEDS FOR AND ALTERNATIVES TO (NFAT) UPDATE

BACKGROUND PAPER B: NEEDS FOR AND ALTERNATIVES TO (NFAT) UPDATE

The Needs For and Alternatives To (NFAT) review took place in 2013/14. During the course of the NFAT review, 15 development plants were considered and analysed, leading to the ultimate PUB recommended plan being approved by Government. The NFAT review considered in detail a wide range of possible future economic conditions and rate scenarios in coming to its ultimate recommendations.

The Hydro 2017/18 and 2018/19 GRA presents an updated picture of the plan as it is unfolding based on the latest information and forecasts. In general, Hydro's portrayal of the plan is that the new information regarding the plan (capital costs, export prices, etc.) presents an untenable risk, that the projects are significantly deteriorated compared to past outlooks, and that Hydro is not adequately prepared to absorb the completed projects.[1]

This paper reviews the data considered at the NFAT in relation to the updated forecasts. It includes the following sections:

1) NFAT Analytical Approach;
2) The Net Cost of Hydro's Domestic System under NFAT Plans Compared to Current Forecasts; and
3) NFAT Retained Earnings and Debt Levels Compared to Current Forecasts.

1. NFAT ANALYTICAL APPROACH

The NFAT economic analysis was completed focusing on an economic analysis (Appendix 9.2) of the 15 plans under varying conditions for three major variables: (i) export/fuel prices, (ii) discount rates (representative largely of differing borrowing costs), and (iii) capital costs. Each variable was forecast for Reference conditions, as well as High and Low conditions. As such the sensitivity testing done during the NFAT included 27 combinations for each plan reviewed (3x3x3).[2]

Of the 15 development plans, 8 were advanced beyond the economic analysis and included in the 40 year financial modelling sensitivity analysis (Appendix 11.4). The financial modelling was

[1] Tab 2, pages 1-2, Manitoba Hydro 2017/18 & 2018/19 GRA.

[2] The sensitivity testing done during the NFAT included 27 combinations for each plan reviewed – low, reference, and high forecasts for economic indicators (U.S. and Canadian, short- and long-term interest rates, inflation rates including US gross domestic product implicit price deflator, CA/USD exchange rate, and Manitoba Hydro's real weighted average cost of capital), energy prices (natural gas, electricity and carbon prices and resulting export prices), and capital costs (generation costs for all resource types, transmission costs and applicable real escalation) per Manitoba Hydro NFAT Business Case, Chapter 10 – Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities, page 4 – 5 of 62. To consider the range of forecast outcomes in this analysis the High Economic Indicators, Low Energy Prices and High Capital Cost scenario reflects the worst set of forecast financial outcomes while the Low Economic Indicators, High Energy Prices and Low Capital Cost scenario reflects the best set of forecast financial outcomes.

more comprehensive than the economic analysis in that the financial modelling looked at the Corporation as a whole (not just the incremental effects of the new development) as well as interrelated impacts like debt financing and interest effects. The financial modelling permitted assessment not just of whether a given plan was likely to be economically viable over its life, but also whether the Hydro organization as a whole could handle the plan, given the relative magnitude of the plan in relation to Hydro's then-existing size and financial targets, the timing of cash and income effects, etc. For example, favourable economics may be seen by a plan that is viable over its life, but if too much of the economic benefits/return only arise in the later decades of the plan, or the initial investment is too large for Hydro to handle, the financial modelling would flag these issues.

Ultimately, during the course of the NFAT proceeding, the decision matrix was simplified from 15 unique plans to focus more on staging (MH Exhibit 192), which lead to framing the NFAT as a deliberation on two key near-term decisions:

1) Do you proceed with an advancement of Keeyask along with a 750 MW line to the United States and a 250 MW sale to Minnesota Power?
    a. If no, then pathways lead to no further decisions needed at that time (included plans 1, 2, 7, 8, 10, LCA/MH I-336).
    b. If yes, then address question #2:
2) Do you continue to protect and advance Conawapa for possible early in-service?
    a. If no, then proceed to plans 5/6 (or possibly 12, if much later pursue Conawapa).
    b. If yes, this was Hydro's Preferred Development Plan, which was plan 14.

Ultimately the PUB recommended the scenario represented by 2(a) of the above framework (proceed with Keeyask and 750 MW line, do not protect Conawapa for early in-service). This recommendation comprises 2 similar plans (Plan 5 and Plan 6) distinguished by a detail on the export contracting. Of those plans, there is a difference in the available data regarding NFAT forecasts:

- Plan 5 is the closest match to the resource plan recommended by the PUB and pursued by Hydro since the NFAT.[3] Hydro did provide updates during the NFAT on financial forecast information under reference conditions for Plan 5, but did not provide the full Plan 5 modelling for all of the 27 risk sensitivities.
- Plan 6 is very similar but did not lock in the export arrangement with Wisconsin Public Service (WPS) (export power was assumed to be sold under alternative market

[3] Specifically Hydro mentions in MIPUG/MH I-2f that Plan 5 from NFAT Exhibit MH-104-12-4 starting on pdf page 37 is the most representative.

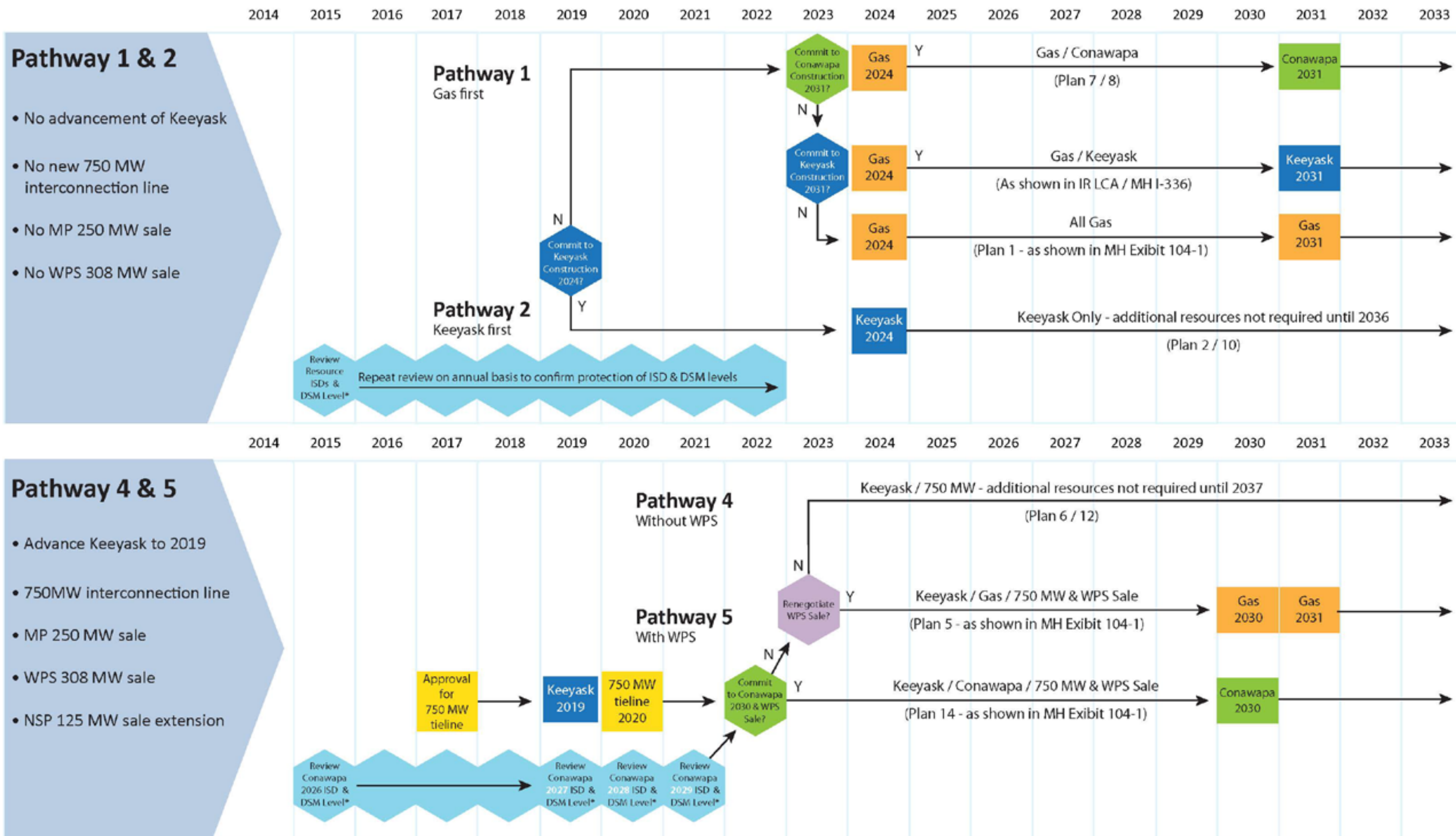
conditions). However, Plan 6 received more detailed modelling in the NFAT scenarios, including financial analysis under the 27 risk sensitivities.[4]

This review considers Plan 5 information[5] where available and Plan 6 data where Plan 5 is not available. The financial modelling of these plans led to extremely similar outcomes except that Plan 6 had somewhat more exposure to energy price swings (given the export power was not locked in under contract to WPS).

The ultimate NFAT decision matrix is shown in Figure B-1 below, which is an exhibit from the NFAT known as the "Update to Figure 14.2" (MH Exhibit 192) from that hearing.

[4] The financial modelling of the 27 Plan 6 risk scenarios were not fully updated for input data changes that occurred during the course of the NFAT hearing, so the risk scenarios are slightly dated compared to the final REF-REF-REF scenarios modelled.
[5] Known as KEEYASK - GAS (5) - DSM Level 2 Main Submission Methodology.

Figure B-1: Pathway Decision Tree - ISD's based on 2013 Load Forecast, Level 2 DSM & Pipeline Load[6]



*ISD protection contingent on additional export contracts, export prices, load growth, DSM, etc.

[6] MH Exhibit 192. Update to Figure 14.2. 2013 NFAT proceeding.

Figure B-1 above shows the decision matrix for NFAT, with the pathway selected shown on the bottom half of the page (Pathway 4 & 5). Note that 2017 and 2018 are still very early in the overall process of unfolding that plan. Decision points continue to unfold along that decision matrix.

2. THE NET COST OF HYDRO DOMESTIC SYSTEM UNDER NFAT PLANS COMPARED TO CURRENT FORECASTS

Each of the NFAT plans reflected different assumptions regarding the generation and transmission to be developed, contracts to be entered into, etc. As a result, each resulted in a different net cost to the domestic system that must ultimately be paid by Manitoba ratepayers.

It is to be expected that each of the key forecasts made in a resource planning context will turn out to be, to some degree, not precisely what actually occurs. The key assessment of whether a plan is unfolding as intended must consider the combined or net effect of the forecasts. One way to make such an assessment is to focus on the net impact on the costs of the domestic system, which includes all of Hydro's costs that ratepayers must cover – all accounting costs to run the entire system, less the export revenues that help pay for the system. This measure can provide a picture of the current situation and forecasts, encompassing all changes that have occurred on an equitable footing (all changes are effectively converted back into a measure of what ratepayers will be required to pay, tracked to the year that the cost arises).[7]

The net cost of Hydro's domestic system under various forecasts are set out in Figure B-2.

[7] Note that this measure does not specifically reference the rates actually paid in any given year, since the rate paid may exceed or fall short of measured costs in a single year. Reserves (and net income) are to be ignored, as this is not a direct cost of Hydro's operations per se, but a key item for consideration over and above covering valid costs.

Figure B-2: Net Cost of Hydro's Domestic System (before reserves) of NFAT Plan 5/6 versus IFF16, IFF15, and IFF14[8]

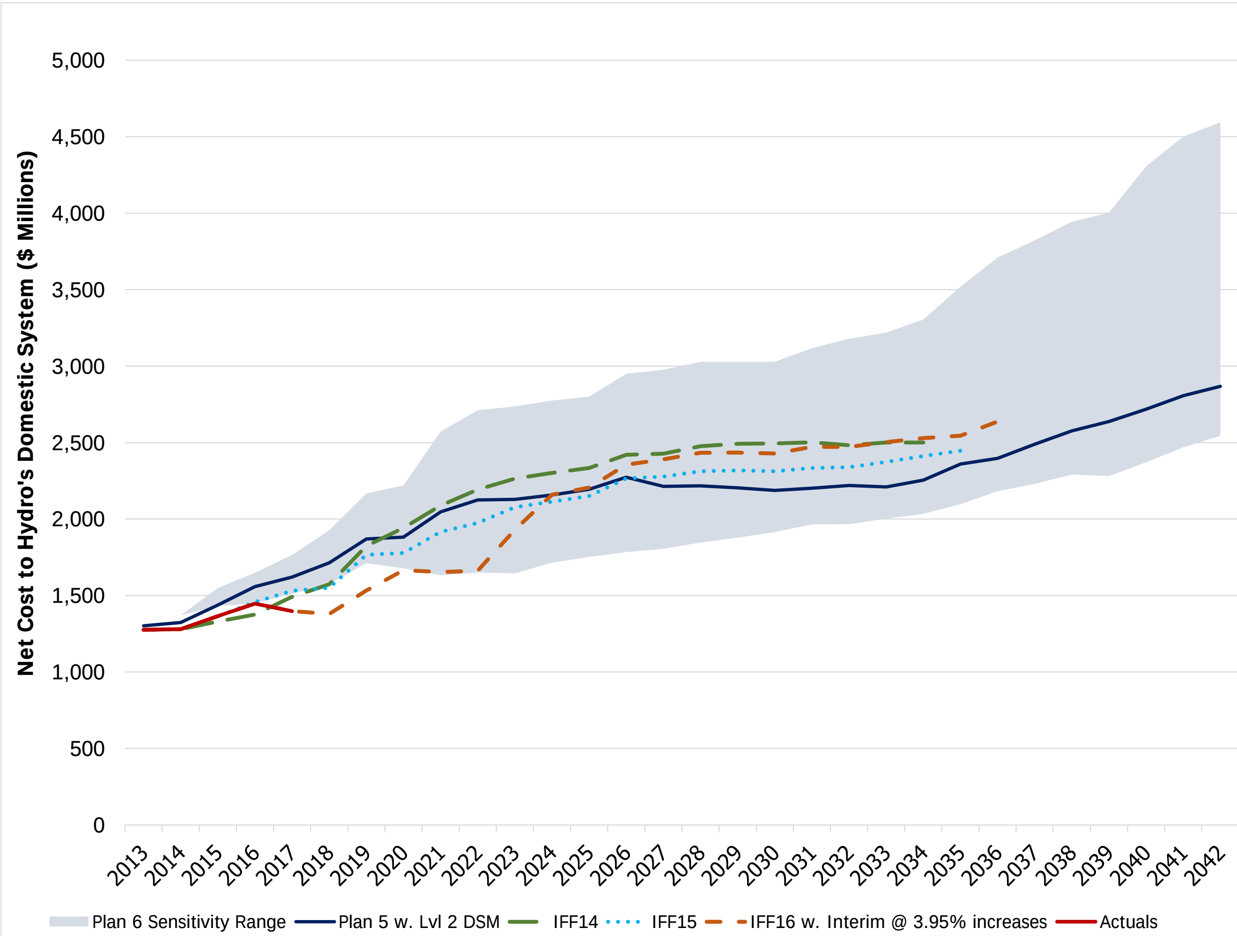


Figure B-2 above illustrates that in terms of net cost to ratepayers, the IFF16 scenario[9] based on current forecasts, including updated Keeyask and Bipole III costs and export prices, has remainder with the range of scenarios considered at the NFAT. Net costs to ratepayers continues to see slow growth to slightly over $2 billion once Keeyask is in service (now projected to be slightly later than assumed at NFAT), and the IFF16 scenarios remain well within the range that was contemplated by the PUB as part of the risk scenarios associated with Plan 5/6. The main exception is found in the early years, pre-Keeyask in-service (to 2022/23), where net costs today and through 2022/23 are lower than would have been expected given

[8] Calculated as Total Expenses each year less extra-provincial revenues and other revenues to represent expenses covered by domestic revenue 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, IFF14 from Appendix 3.3 in 2015/16 GRA; IFF15 Attachment 1 in 2016/17 Interim Rate proceeding; IFF16 with Interim at 3.95% rate increases from PUB/MH I-34 Attachment 2.

[9] The measurement in the figure does not rely upon rates paid, but rather net costs less export revenues. However, interest costs are to some degree a function of rates paid. The above figure assumes the IFF16 3.95% rate increase scenario, which is a close comparator to the Plan 5/6 rate scenarios which are shown in the same figure.

NFAT forecasts. It is expected that part of the benefit is due to higher than average water that has been experienced.

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.[10] This would serve to depress costs compared to the now proposed ELG method.

2) The long-term projected costs of DSM are higher in IFF16 than in the NFAT, which contributes to overall system costs.

Absent these two factors, the IFF scenarios in future would more closely resemble the costs under NFAT reference conditions.

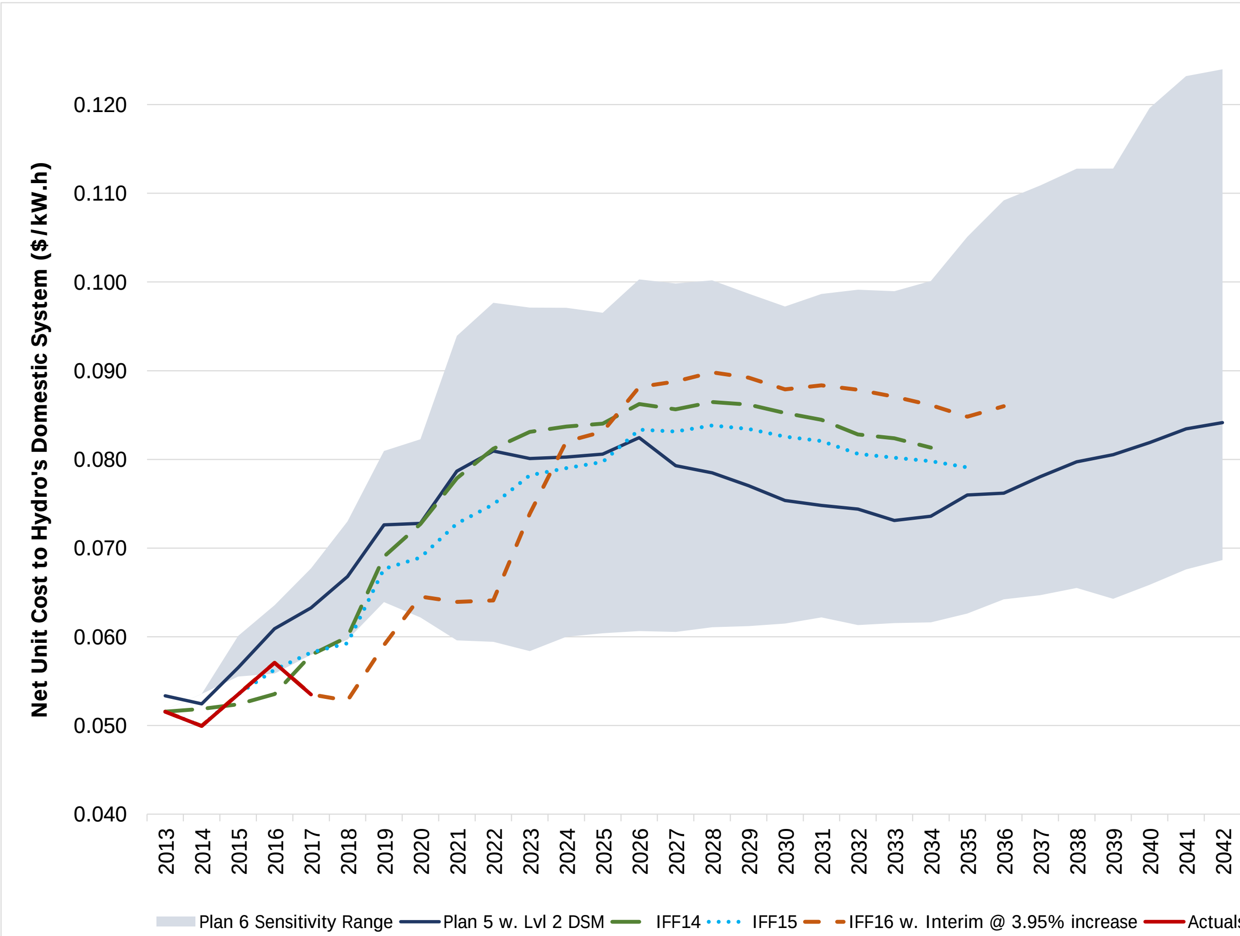
In short, notwithstanding adverse cost movements on the major projects that have occurred in recent years, and downward price revisions on export prices, other offsetting factors have played a significant role in making up the difference (or more than made up the difference in terms of years pre-Keeyask years).

It is important to remember that Figure B-2 above is net costs before setting aside reserves or Net Income – changes to policies on these matters will also affect ratepayers.

One change that has occurred to adversely affect the ratepayer economics is a reduction in the domestic load forecast (including effects of DSM). The above Figure B-2 focuses on total amounts to be paid by domestic ratepayers, but the picture looking to average rates (total to be paid divided by total sales) is provided in Figure B-3 below.

[10] Transcript page 3339, 2013 NFAT proceeding.

Figure B-3: Net Unit Cost of Hydro's Domestic System (before reserves) Calculation for NFAT Plan 5/6 versus IFF16 (assuming 3.95% increase scenario)[11]



Similar to the previous figure, on a unit cost basis, the development plan as it is unfolding leads to net costs to ratepayers below or in the range of the reference case from NFAT until after 2025, and somewhat higher costs thereafter. Also similar to the Figure B-2 above, these adverse movements in later years are being driven by the proposed use of ELG depreciation for the major new capital projects, plus the compounded effects of DSM on both adding to Hydro's

[11] 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.

costs, and reducing the load available to pay those costs (with only limited benefits from added export revenues).

Notwithstanding the above two matters, the development plan under IFF16 remains well within the middle of the range of risk scenarios considered at that time and below that range prior to Keeyask in-service in 2022/23.

For reference, the NFAT reference case values and the IFF16 values underlying the above two figures are provided in Table B-1 below.

Table B-1: Net Unit Cost of Hydro's System (before reserves) Calculation for NFAT Plan 5 versus IFF16 (assuming 3.95% increase scenario)[12]

$ 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

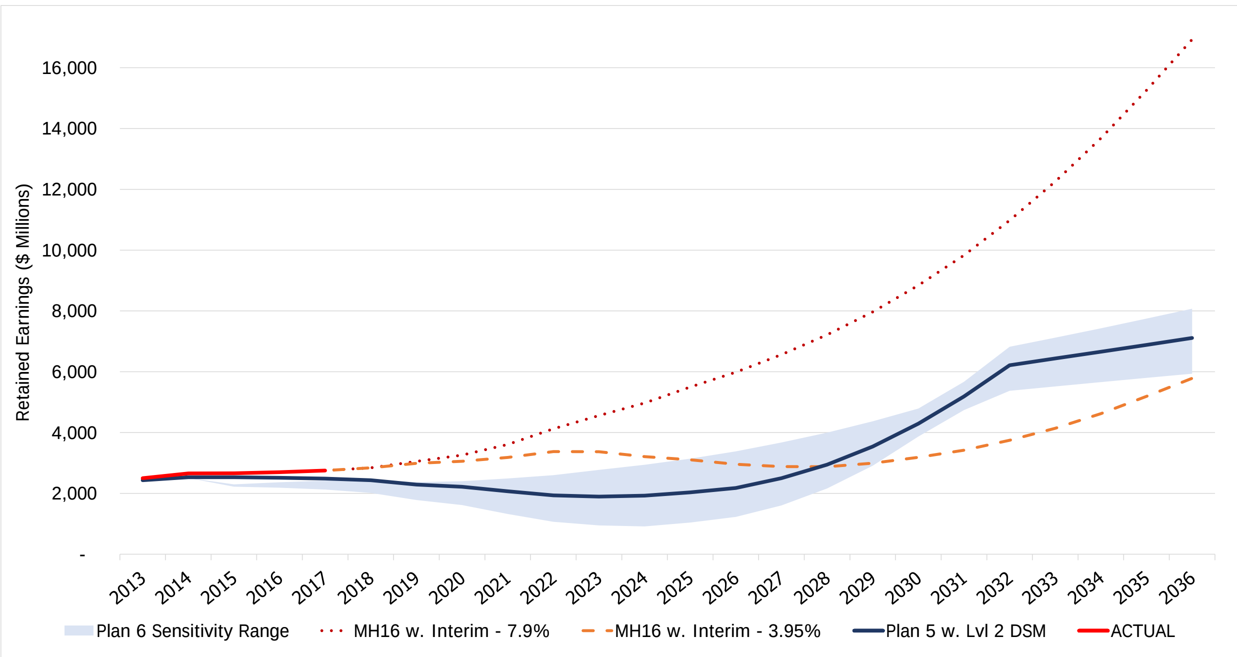
[12] Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets divided by 2013 Load Forecast with Level 2 DSM Appendix D in NFAT (less 2014-17 PowerSmart Plan savings at meter page 56 of 86 Appendix 8.1 in 2015/16 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.

3. NFAT RETAINED EARNINGS AND DEBT LEVELS COMPARED TO CURRENT FORECASTS

The NFAT scenarios also provided an analysis of the range of future net income and retained earnings that could arise.

The NFAT rate design scenarios were not completed on a highly refined basis, so year-by-year changes in retained earnings may be less informative than the long-term trends, which are set out below. The pattern of retained earnings under the NFAT forecasts (Plan 5/6) as compared to IFF16 updated scenarios (3.95% increases and 7.9% increases) is set out in Figure B-4 below.

Figure B-4: Retained Earnings of NFAT Plan 5/6 versus IFF16 (with both 3.95% and 7.9% rate increase scenarios) $ Millions[13]



As shown in Figure B-4 above, the pattern of retained earnings under NFAT (shaded section and blue line) looked to a lengthy period after Keeyask in-service (2019) before substantial movement would occur towards a higher retained earnings level, of about 8-9 years (to about 2027/28). Adverse scenarios (bottom of shaded section) showed retained earnings dropping to the $1 billion level, recovering by about the 10th year of Keeyask (2029). It is important to note that the NFAT risk scenarios are based on average of all water flows, so the specific event of a

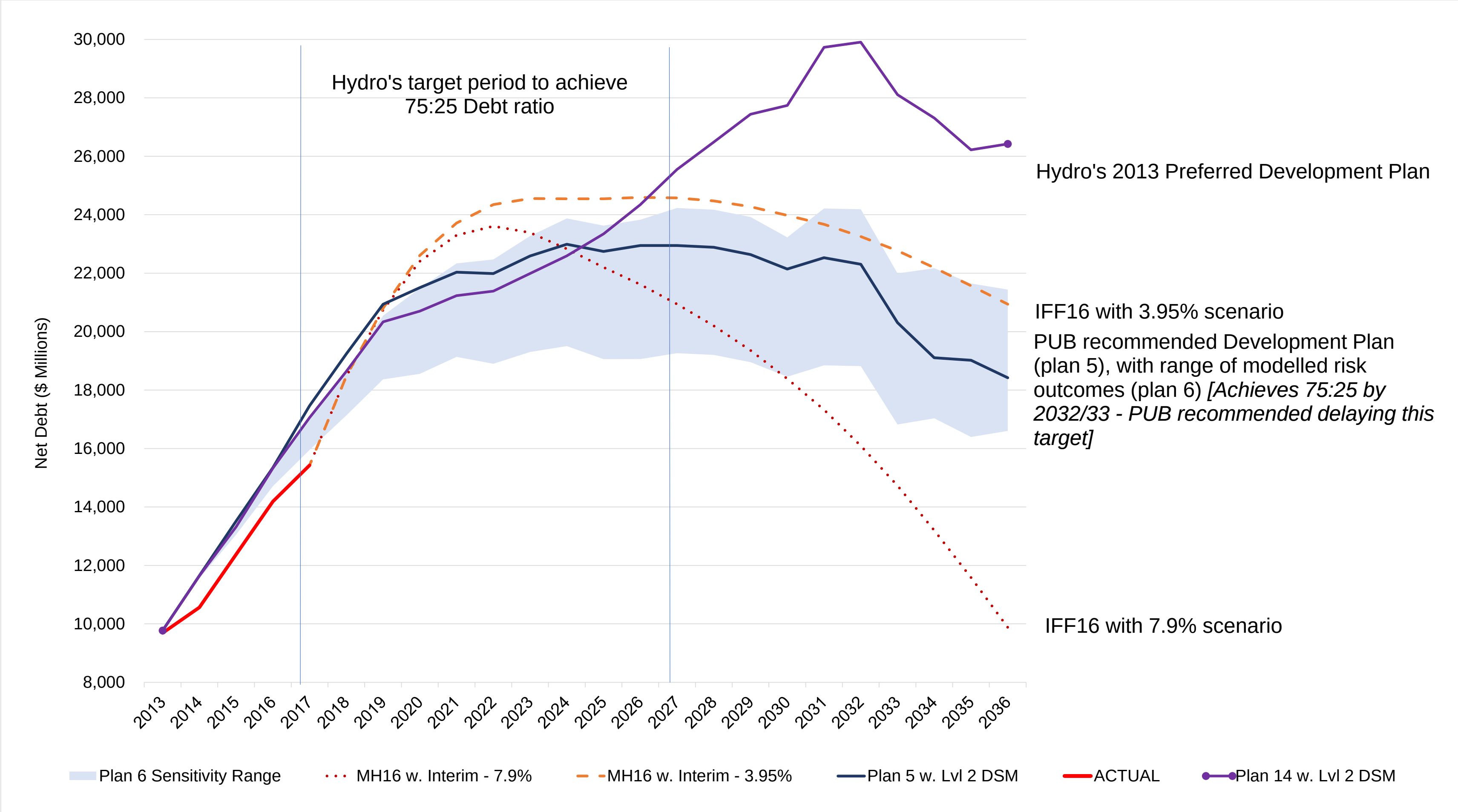
[13] Plan 6 (K19/Imports/Gas/750MW) range includes 27 economic sensitivity analysis scenarios provided in Appendix 11.4 spreadsheets in NFAT Review, Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets, IFF16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

major drought during this time would be a further reduction compared to the blue shaded area shown in Figure B-4.

Comparing the IFF16 scenarios to the NFAT projections, it is clear that under either scenario (3.95% (orange) or 7.9% (red)) retained earnings are significantly improved through the new in-service date for Keeyask (2022/23) compared to any risk scenario considered at NFAT. The 3.95% scenario then shows a pattern largely matching the NFAT scenario but delayed approximately 4-5 years (the orange line begins to climb about 4-5 years after the NFAT scenario shows improvement the start of improvement) – this is consistent with a later Keeyask in-service. Of note, under the 3.95% scenario, the minimum retained earnings forecast is on the order of almost $3 billion (about 2029) where NFAT scenarios expected at reference conditions to slip below $2 billion, and under adverse conditions to slip to approximately $1 billion (about 2024).

The IFF16 scenario with 7.9% rate increases portrays a significantly different pattern as shown in the red line in Figure B-4 above. The end result of the retained earnings increase under the 7.9% scenario is a material reduction in the level of net long-term debt, as shown in Figure B-5 below, which is further addressed in Background Paper A.

Figure B-5: Manitoba Hydro Net Debt under NFAT Scenarios and Updated IFF Scenarios at 3.95% and 7.9%[14]



[14] 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 MPUIG/MH-I-2g.

BACKGROUND PAPER C:

UNCERTAINTY ANALYSIS AND RISK SCENARIOS

BACKGROUND PAPER C: UNCERTAINTY ANALYSIS AND RISK SCENARIOS

The current Hydro GRA includes, for the first time, a major new area of analysis based on quantifying risks that had been requested by the PUB since at least 2008 (Order 116/08)[1]. The new analytical product, termed the "uncertainty analysis", was first made available to the PUB and intervenors in the 2016 Interim Rate review, but has not been fully reviewed or tested in a GRA to date.

At its heart, the uncertainty analysis is different than previous Hydro analyses in the following ways:

1. **Multiple overlapping risks:** The analysis looks at not just the effect of single risks, but also combinations of risks (e.g., a bad drought combined with adverse interest rate movements). The three most variable risks faced by Hydro are included – export prices, water flows and interest rates. Discrete but unquantifiable risks (e.g., positive or adverse policy changes outside of those already included in export price forecasts, infrastructure failure) are not included.

2. **Full probabilistic range:** The analysis considers not just a single given scenario (such as the worst case) but a combination of future scenarios to give a portrayal of the probability of a given outcome, rather than just the implications of the worst possible outcome.

3. **Integrated modelling:** The analysis permits scenarios to be considered in their entirety, rather than just a single effect. For example, previous risk analyses had tended to indicate that a 5 year drought would reduce retained earnings by a given dollar impact compared to what would have occurred without the drought. But this portrayal fails to indicate that absent the drought, there would likely have been a positive net income over this 5 year period. For example, if a 5 year drought "cost" $1.5 billion, but over this five year period the IFF had forecast $1 billion in net income at normal water, then the adverse effect on Hydro's retained earnings from the drought is only $0.5 billion over those 5 years. In this manner, the previous system tended to give results that appeared excessively pessimistic by focusing on the value like $1.5 billion – the new uncertainty analysis helps improve on the information presented.

Despite these advances, the modelling still fails to include a mechanism for rate response – where each scenario run by the computer does not rely on a fixed rate increase path, but instead on annual increases that are adaptive and responsive to the ongoing conditions (e.g., raises rates more than average, but with a constrained set of bounds, if poor conditions require, less than average if good conditions permit).

[1] Directive 12.

This background paper addresses two aspects of the new uncertainty analysis:

1) What does the results of the analysis tell us?

2) How can it be improved?

Each of these items is addressed below relying on the materials filed in the current GRA.

For reference, the uncertainty analysis for the current IFF16 is provided in Tab 4, particularly Section 4.5. Earlier uncertainty analysis conducted on IFF15 is contained in Appendix 4.2. Significant additional material is contained in MIPUG/MH I-1a (Tab 4 figures extended to 20 years) and MIPUG/MH I-3c (Tab 4 charts with alternative scenario weightings). KPMG also reviewed and commented on the IFF16 uncertainty analysis in Appendix 4.5. Finally, the uncertainty analysis was updated for MH16 Update with Interim in PUB/MH II-41a-b.

1. WHAT DOES THE UNCERTAINTY ANALYSIS TELL US?

The uncertainty analysis focuses on a large range of future scenarios, which permits an assessment of not just the potential for a given outcome to occur, but also the likelihood of that outcome. The probability ranges charted focus on 50th percentile (the middle scenario – with an equal number of scenarios that are better than this outcome and an equal number that are worse than this outcome). Around this value, a box and whisker plot shows the 20th and 80th percentile as the “box” (the 20th being the value where 1 in 5 scenarios are worse than this value, and 4 in 5 are better; the 80th vice versa) and the 5th and 95th as the “whiskers” (the 5th being a value that has 1 in 20 scenarios worse than this value, and 19 out of 20 better; the 95th vice versa). An example is reproduced in Figure C-1 below.

Figure C-1: Comparison of the Annual Net Income Variability[2]

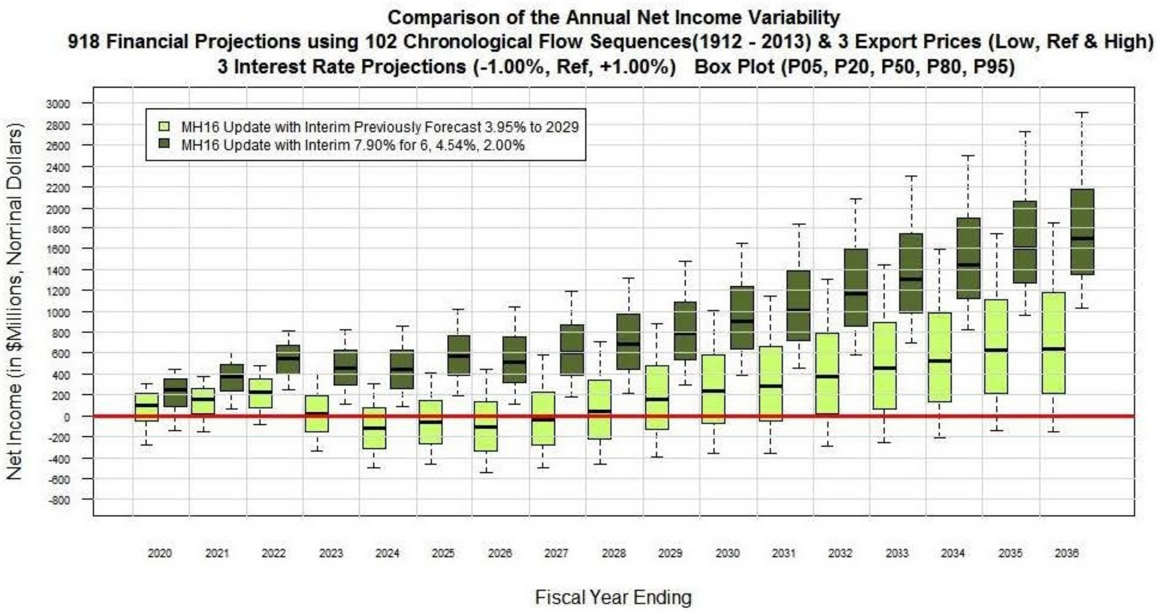


Figure C-1 shows the net income, by year, generated by the uncertainty model. It shows the box and whisker plot for two scenarios – one with 3.95%/year rate increases to 2029, followed by 2%/year (the light green), and one with the 7.9%/year rate increases for 6 years followed by 4.54%, and then 2%/year (the dark green).

The box and whisker plots read as follows, using an **example year of 2022:**[3]

- Looking to the **7.9% scenario** as proposed by Hydro (the dark green box-and-whisker plot) shows the 50th percentile outcome to be $546 million net income in that year.
- The 20th and 80th percentiles range from $402 million net income to $673 million net income (6 out of 10 times net income would be expected to fall within this range).
- Looking to the more extreme "whiskers", the results show that the 5th percentile (19 times out of 20) net income would exceed $244 million, but the 95th percentile would be $811 million (only 1 time in 20 would this be exceeded). Note that results anywhere within this range can be compared to Hydro's previous record high net income of $415 million in 2006.
- Comparing to the **3.95% scenario** (light green), the 2022 values show a 50th percentile net income of $221 million.
- The 80th and 20th percentile values are $351 million and $76 million (6 out of 10 times the net income would be within this range).

[2] PUB/MH II 41a-b, page 7 of 16.
[3] All values per PUB/MH II 41a-b page 8.

- The 5th percentile shows a net loss of $80 million, with the 95th at well above $483 million.

In reviewing Figure C-1 above, it is important to note that the 5th percentile line in any given year is not necessarily the same scenario that leads to the 5th percentile line in the subsequent years. In other words, looking to the light green line, there is not a 1 in 20 chance that net income will be negative $80 million in 2022 followed by negative $335 million in 2023 followed by negative $497 million 2024 etc. as would be shown by tracking the 5th percentile through the years – these 5th percentile values are not driven by the same underlying scenarios (i.e., the same worst drought does not repeat itself for each year of a 20 year horizon).

The 5th percentile line is also informative regarding droughts. Under the 3.95%/year scenario, the 5th percentile values show the adverse effects in any given year from experiencing a very serious drought combined with other adverse effects. At its worst (2026) the resulting net income is negative $539 million. The interesting part of characterizing the exposure in this manner is that it is highly correlated with the risks Hydro has been exposed to for the last few decades – in particular consider that in 2003/04 a very serious drought led to negative $436 million in Net Income. What is important to understand is that in the 2003/04 case, the drought was not noted to be correlated with adverse moves on interest rates or export prices, which the uncertainty modelling is assuming. It is also important to note that the 2003/04 drought occurred at a time when Hydro's retained earnings were only $1.2 billion and domestic revenues (on which rate increases could be granted) were only $918 million.[4] In today's context, retained earnings are approaching $3 billion and domestic revenue is near $1.6 billion.

In short, the risk exposure characterized by the 3.95%/year case (light green), which shows $539 million in losses in a severe drought in only the worst year (2026), and significantly less in each other year of the sequence, is not uncharacteristically poor for Hydro, if anything it is uncharacteristically good. It is clearly less risk exposure than existed for likely much of the last 20 years or longer.

Figure C-1 emphasizes the effects arising from Hydro's targeting 7.9%/year rate increases for the next number of years (dark green scenario). In particular, the chart shows that Hydro would be seeking to achieve net income that has at most a very small chance of being negative - even in the worst years of the scenario (2020), with compounding adverse effects occurring (e.g., drought combined with unexpectedly adverse interest rate moves and poor export conditions). Outside of a few years that are particularly susceptible to adverse outcomes (e.g., 2023 to 2026) the path is designed to make it more likely than not that each given year of the forecast will be above the existing record net income for Hydro, with many years having a likely 80-90 percent chance that the existing record of $415 million will be exceeded, year-after-year.

[4] Hydro Annual Report 2007, page 100 (Appendix 15 to the 2008 GRA).

Turning to the level of retained earnings, a similar figure is produced for the level of retained earnings in each future year, as shown in Figure C-2 below:

Figure C-2: Comparison of the Annual Retained Earnings Variability[5]

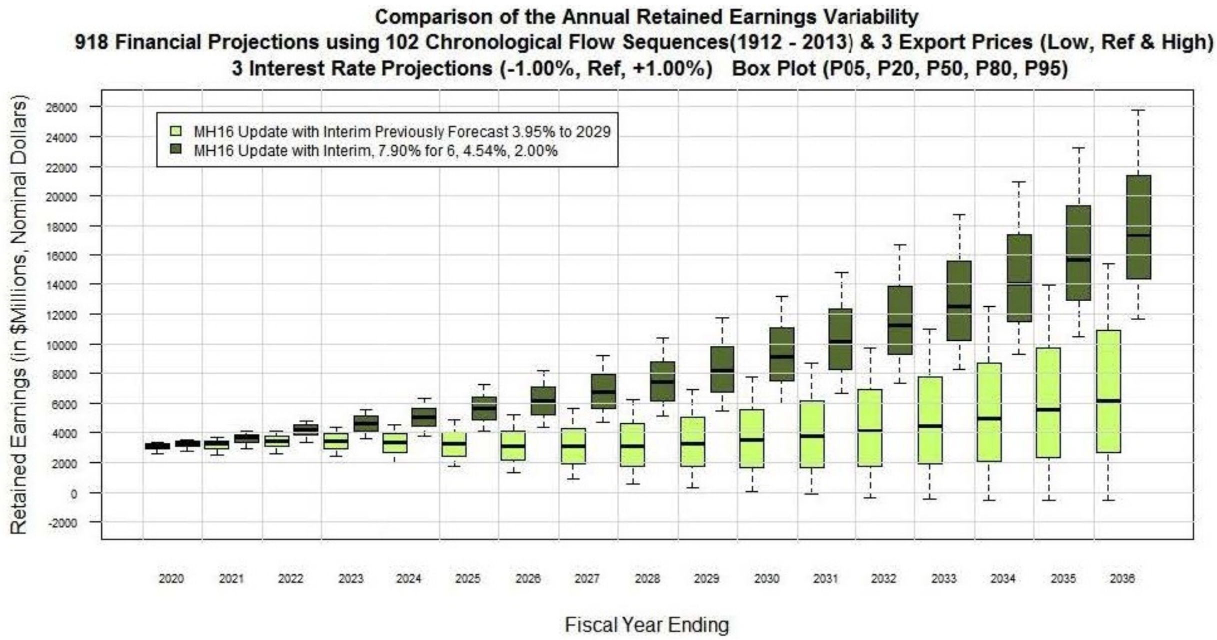


Figure C-2 highlights the retained earnings scenarios, in dollars, for Hydro's two main rate increase scenarios modelled – again, dark green for 7.9%/4.54%/2% and light green for 3.95%. The 50th percentiles emphasize that starting with the approximately $3 billion retained earnings at present, the 3.95%/year rate increase median sustains this over the next decade. After 2027, as the effects of ongoing inflation and rate increases take effect, the retained earnings 50th percentile shows growth to over $6 billion within 20 years. The retained earnings scenarios highlight a further important aspect that over the period to 2024, there is only a 5th percentile outcome that has retained earnings decreasing to $2 billion.

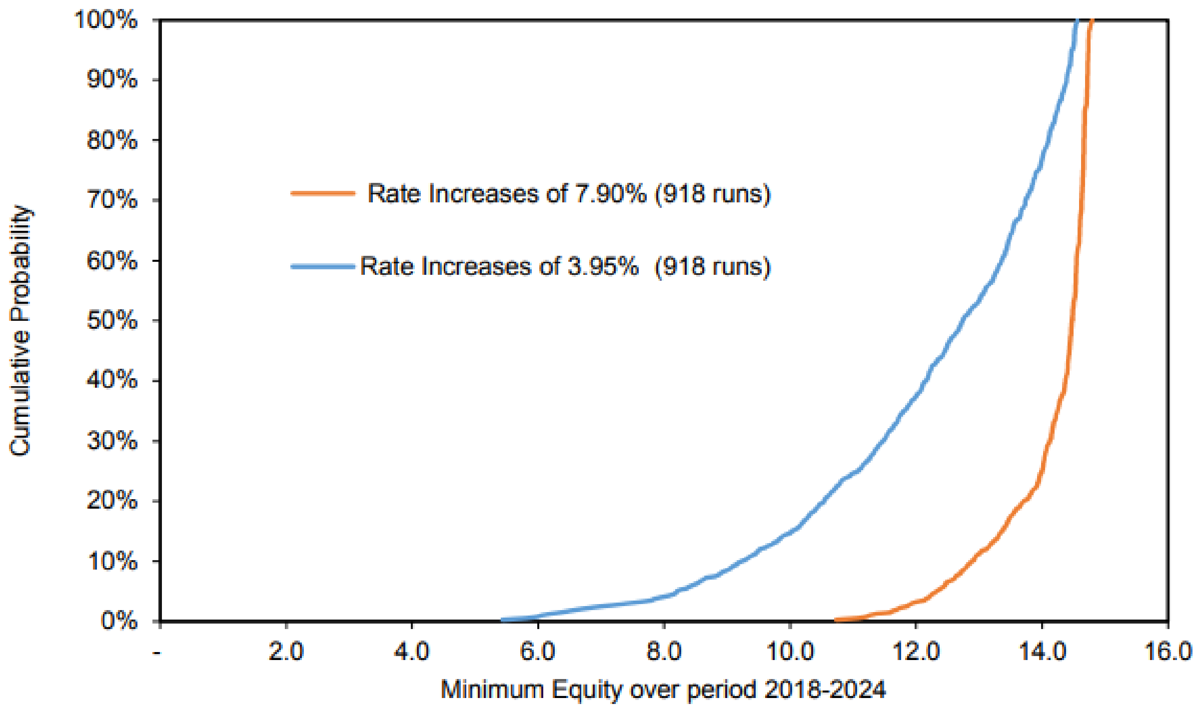
An aspect of the retained earnings scenarios in Figure C-2 is the compounding nature of the range of outcomes (the heighted of the bars and whiskers) given the model applies no rate response, but only a fixed unyielding rate increase scenario. As discussed below, this inability to have rates react to the scenarios as they unfold is a major limitation with the model as developed by Hydro that should be addressed in future. Since this feature does not exist, the fixed unyielding rate increase scenarios mean that if a scenario is knocked off course earlier in the model run (e.g. years 3-8), whether positive or negative, the failure of the rate scenario to react leads to an ever widening cone that is not a reasonable portrayal of the actions that would be expected to be taken. For example, the 20 year range of negative $0.5 billion to positive $15.5 billion for the 5th to 95th percentiles under the 3.95%/year rate increase reflects a failure of the model to adjust rate increases to, say, 4.95% when needed for adverse

[5] PUB/MH II 41a-b, page 11.

conditions, or 2.95% when possible for exceeding financial expectations. Nonetheless, the 50th percentile values should remain reasonably accurate, but the outer edges of the cone would be expected to be narrowed with rate response.

KPMG has provided a different approach to portraying the same analysis approach in Appendix 4.5, KPMG Figure 6-15 (reproduced below as Figure C-3) though this appears to be based on the original MH16 conditions.

Figure C-3: Minimum Equity Value Observed 2018 through 2024 Alternative Scenarios[6]



In Figure C-3 above, KPMG provides a snapshot assessment for the 2018-2024 period of the lowest level of Hydro retained earnings for each run (as a percentage of capital) that can be expected given the scenarios modelled. The orange line portrays the scenarios tied to 7.9%/year rate increases and the blue line to 3.95%/year rate increases. The form of the chart shows that if 7.9%/year rate increases are adopted, there is effectively no risk (considering the variables modelled) that Hydro would hit, at any time during the 2018-2024 period, a retained earnings level that is below about 11% of capital. With 3.95%/year increases, there is a small risk that Hydro could hit retained earnings levels between 5 and 6% of capital in at least one year, but not below. The 50th percentile retained earnings ratio is about 14% for the 7.9%/year rate increases and just over 12% for the 3.95%/year rate increases. Under best cases, both

[6] KPMG LLP. 2017. Manitoba hydro Financial Targets Review Supplementary Update. Appendix 4.5 of the Manitoba Hydro 2017/18 & 2018/19 GRA. August 2017. Figure 6-15, pg. 75.

scenarios have a minimum retained earnings at 14% (which is approximately the 2018 ratio, so neither scenario can avoid this minimum retained earnings value).

Note that neither scenario above applies any rate response – even in the worst conditions, each approach sticks to the 3.95%/year or 7.9%/year rate increases characterizing the scenario. Also note that due to this lack of rate response, neither scenario comes close to the situation KPMG highlighted as being where Hydro would no longer be self-supporting, i.e., "…a position of near zero retained earnings and rates have increased in real terms such that Manitoba can no longer be considered a cost competitive jurisdiction with respect to electricity rates"[7] (emphasis in original). Under the above scenarios, particularly the 3.95%/year scenario, retained earnings under the worst cases would hit between 5 and 6 percent of capital (slightly below $1.5 billion)[8] for a time and rates would remain among the lowest in Canada[9]. For this reason, Figure C-3 above suggests that if the worst situation were to arise, some level of rate response (higher than 3.95%/year increases) could be applied to further bolster the retained earnings above the $1.5 billion level.

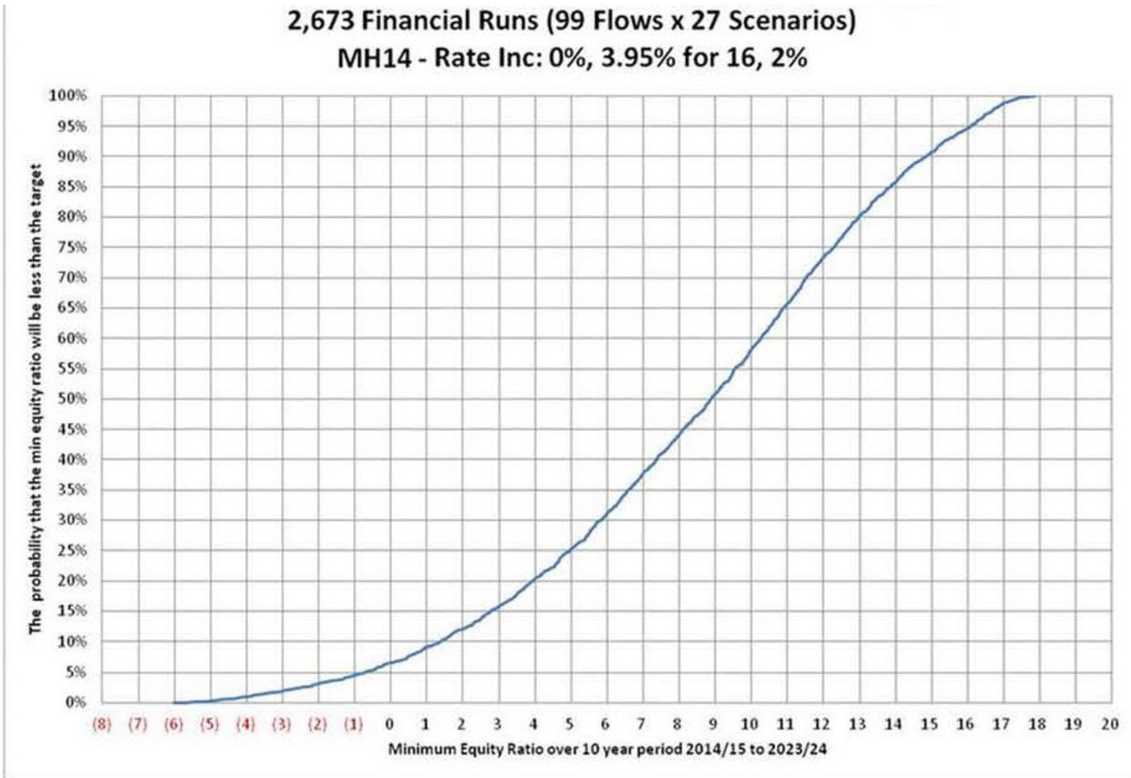
A further benefit of the KPMG presentation format is a high degree of information provided about the range of outcomes (to 2023/24) comparing IFF14 to IFF16. Figure C-3 above provides, in the blue line, the minimum retained earnings percentages arising under IFF16 inputs but using a rate increase scenario similar to IFF14. The same graph based on the IFF14 inputs is provided below in Figure C-4:

[7] Appendix 4.1, page 7.

[8] In 2023/24, per PUB MFR-17, total capital (debt+equity) approximates $27.8 billion, at 5% this totals $1.4 billion.

[9] At 3.95%/year increases the real rate of increase is approximately 2%/year for the 7 years to 2023/24. Other than Quebec, Hydro's application Figure 2.33 highlights that Manitoba's rates are below the other lowest jurisdiction in Canada – BC. Even with 7 years of increases Manitoba's rates would remain competitive.

Figure C-4: Cumulative Probability Graph
Minimum Equity Ratio Over 10-Year Period 2015-2024[10]



Comparing Figure C-3 to Figure C-4 (blue line), it is clear that under effectively the same rate increase scenario, IFF16 has materially reduced the risk of adverse outcomes. In particular, at the time of IFF14, a rigid adherence to 3.95%/year rate increases over the period to 2024 would have provided a 25% chance that retained earnings levels would drop below 5%, and a 6% chance that they would drop below $0 (potentially as low as negative 6% of total capital). These scenarios, though highly unlikely, would be a significantly problematic outcome. Of course, had such conditions arisen after IFF14 was prepared, rate response (e.g., higher than projected rate increases) would have become required.

By IFF16, these extreme results are no longer within the range of modelled outcomes. While IFF14 showed a 1 in 4 chance that retained earnings could drop below 5%, this outcome is no longer shown at even the 1 in 100 level. IFF14 exhibited a 6% chance that retained earnings could drop below $0, this outcome is no longer within the range of outcomes at any probability threshold.

[10] KPMG LLP. 2017. Manitoba Hydro Financial Targets Review. Appendix 4.1 of the Manitoba Hydro 2017/18 & 2018/19 GRA. May 2015. Figure 7-7, pg. 116 (original source: Manitoba Hydro).

At the 50th percentile, IFF14 had showed a minimum retained earnings at 9% of capital. This outcome is now at the 10th percentile (only a 1 in 10 chance of this low an outcome occurring). The new IFF16 50th percentile exceeds 12 percent of capital.

The reason for the narrowing of potential outcomes to 2024 for IFF16 versus IFF14 are twofold:

1) IFF16 shows improvement in a number of critical input conditions, such as interest rates and water levels.

2) More importantly, IFF16 shows the benefits of 2 years of actual known conditions at the outset of the sequence. The IFF16 probability set is all those outcomes that may arise within 8 years to 2024, while the IFF14 was all scenarios that could arise within 10 years to 2024. This is a very important distinction that underlines the critical importance of timing and sequence of risk. In the intervening 2 years from IFF14 to IFF16, a significant reduction in risk has occurred leading to a narrowing of the 5th/95th range. This is due to the normal evolution of facts as major capital projects (and associated borrowing) proceeds. The trend would be expected to continue as Keeyask and Bipole III progress towards completion. This feature is highly informative to the need for attentive, but measured, responses during the critical years to 2022/23 as risks are carefully monitored and resolved.

2. HOW CAN THE UNCERTAINTY MODELLING BE IMPROVED?

Hydro's uncertainty modelling is a significant improvement on the ability to assess and analyze future potential events. Three potential improvements have been identified, but two of the potential improvements are not likely to materially change the results.

Improvements that are important to the next evolution of the modelling:

1) Include rate response.

Improvements that are possible, but unlikely to materially affect the modelling results for IFF16:

1) Determine if additional risks should be included in addition to the main three risks already included (interest rates, export prices and water flows).

2) Consider alternative weighting for input values (e.g., are low/high prices just as likely as the expected prices, or are they somewhat less likely).

Each is addressed in the sections below.

2.1 Rate Response

The most notable omission from Hydro's uncertainty analysis is the failure to include any mechanism for automated rate response in the analysis. This means that the scenarios show excessive divergence from targeted financial performance as rate increases continue to be enforced by the model in situations where they are nonsensical. For example, the model may show that there is a risk, if a 3.95%/year rate regime is implemented, that equity will turn negative and continue eroding, or at 7.9%/year that Hydro will exceed 50% equity and $1 billion in net income yet continue to raise rates. The result is that the projected cones are much wider than can reasonably be expected.

The same issue was present to some degree in the NFAT hearing, where multiple scenarios were similarly being examined. In that case Hydro developed a simplified rate response regime that could be applied by the computer within the modelling (targeted to interest coverage each year). Hydro's approach was better than using an unresponsive fixed rate regime, but was coarse. In particular, Hydro's scenarios forced a specific rate increase for 20 years (tied to the specific development plan), but then let the rate increases respond to the measured Interest Coverage ratio without constraint after year 20. The result was an overly rigid rate increase regime in the first 20 years, and an overly frenetic rate scenario in the years after year 21 (e.g., sometimes with double digit rate increases in one year followed by double digit decreases the next).

Morrison Park Advisors, as an Independent Expert Consultant retained by the PUB, provided modelling that was more sophisticated in terms of rate responsiveness. The Morrison Park modelling implemented a given rate level for each year, and then adjusted the rates the next year to reflect the evolution of conditions so as to either achieve or proceed towards a given financial target – but the rate changes were constrained to a reasonable range (the maximum increase or decrease was fixed at two times inflation).[11]

In the case of Hydro's current uncertainty analysis, this could be implemented by modelling a rate regime based around a given starting baseline percentage increase, but if conditions trended adverse, an increase somewhat higher than this level could be used (e.g., 2% higher than baseline)[12] and if conditions were better than expected, a lower than baseline increase could be assumed (e.g., 2% below baseline). In each scenario, for each year of the model, the calculation would start with assessing which rate increase would be implemented.

The specific financial criteria to be met to trigger each respective rate increase level would need further development, but would likely be able to be based generally around Hydro's financial targets. For example, in assessing the rate increase to be applied to a given year, if the Interest Coverage Target was being missed to the downside then the higher rate increase may be used in that year, while if the debt-to-capital pathway that leads to a given debt percentage within a given number of years was being materially exceeded, then the lower rate increase would be used in that year.

[11] MH/MPA I-007 from the 2013 NFAT proceeding.

[12] In the last major drought – 2004 – the PUB decided to implement a 5% rate increase, compared to a 3% sought by Hydro. A reasonable inference could be that 2% above baseline is an accepted response to adverse conditions occurring.

The results of such modelling would yield two beneficial results:

1) The modelling would permit answering critical questions – including whether a 3.95%/year pathway (recognizing the potential for a 5.95% increase if conditions are significantly poor, and 1.95% if conditions are above expectations) would provide sufficient or potentially even excessive risk protection. This could be compared, for example, to scenarios with a 3%/year baseline and a +/-3% boundary or other alternatives, offering a lower initial rate increase to customers but perhaps a slightly higher risk of instability in rates.

2) The modelling would allow the PUB to signal endorsement of not only a current rate increase, but a possible future pathway (including pre-assessed rate responses) to address Hydro's known risks should they arise. This has the potential to provide an added degree of comfort and clarity to lenders and credit ratings agencies about the regulatory responses that are able to be brought to bear to deal with future adverse conditions, though such signalling would not be intended to in any way fetter the Board's discretion to act according to the best evidence at the time each future rate increase is sought.

It is expected that rate response would permit a much more accurate portrayal of the financial scenarios that is representative of a given pathway available. The tool would permit scenario evaluation that informs whether a specific rate increase in the first 1-2 years exposes the company to potentially needing rate shock increases in future years under reasonably foreseeable adverse conditions. If such risk was not exhibited, then it could provide comfort that the specified rate increase was reasonable and appropriate in the first years under review.

2.2 Modelling of Additional Risks

The uncertainty model incorporates risks for export prices (which also affects fuel used during low flow scenarios), interest rates and water flows. Hydro's traditional deterministic risk register from the IFF includes a number of additional variables. In the case of IFF16, the measured impacts to retained earnings over the 10 years to 2026/27 for uncontrollable risks[13] are as follows (in terms of adverse impact in retained earnings)[14]:

- Drought (5 year impact) - $1.367 billion;
- +1% interest rates - $0.930 billion;
- Low export prices - $0.777 billion;
- Canadian US dollar exchange rate down $0.10 (C$ strengthening) - $0.220 billion; and

[13] Two other scenarios are also modelled related to Hydro adding to capital expenditures, but these are not uncontrollable risks and do not fit the profile for inclusion in an uncertainty analysis so are not included above.
[14] IFF16, page 44.

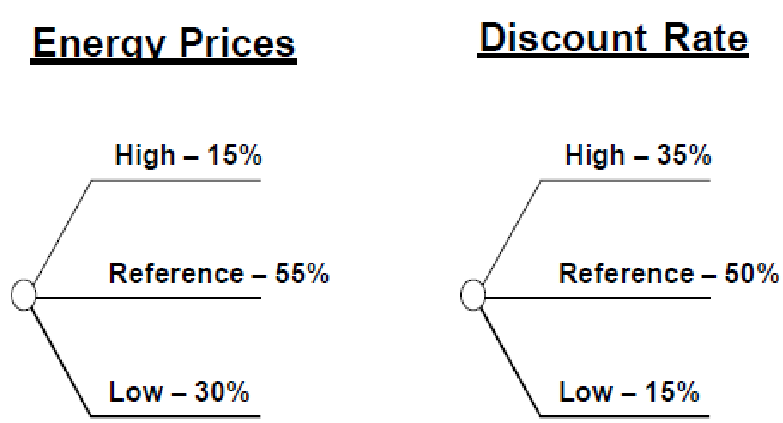
- Low domestic load growth - $0.179 billion.

As can be seen from the above list, the uncertainty analysis already includes by far the biggest 3 risks that dominate Hydro's future exposure to adverse outcomes, and as such it is unlikely there would be significant benefit from adding to the analysis scenarios with varying exchange rates and domestic load growth.

2.3 Alternative Weightings

A final area of potential improvement is to explore the impacts of using alternative weightings for the respective reference, low and high input values (interest rates and export prices). Hydro's uncertainty modelling uses equal weights of 1/3 to each[15] value. During NFAT, Hydro had a more refined weighting system as shown in Figure C-5 below (reproduced Figure 2.15 from NFAT Appendix 9.3):

Figure C-5: Probabilities for Highest Impact Factors[16]

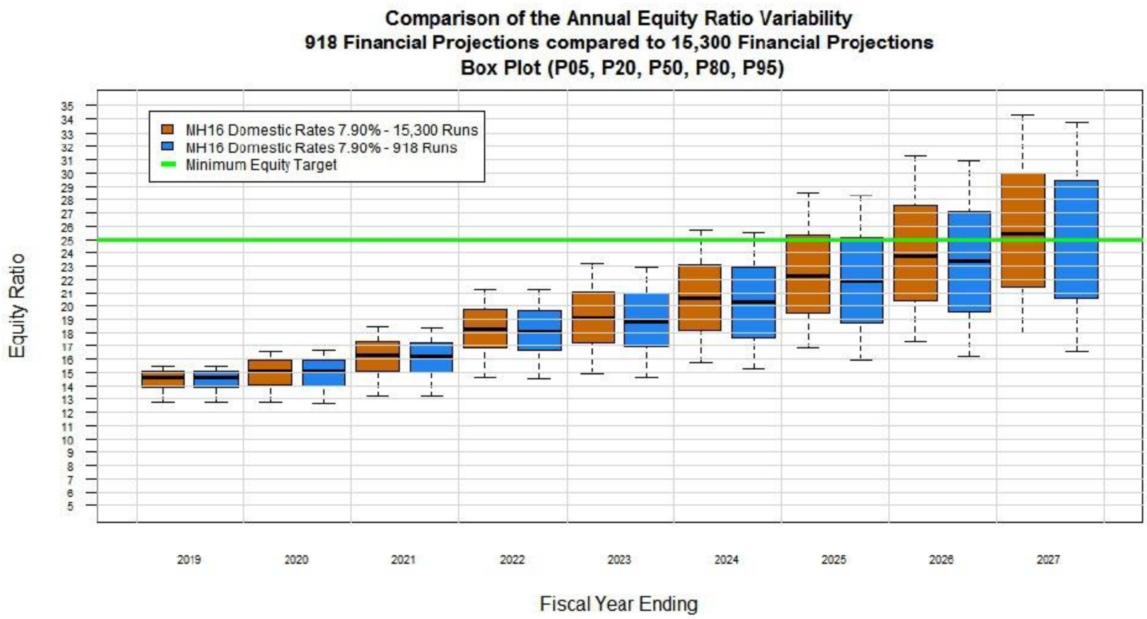


The above Figure C-5 shows that at the time of NFAT, Hydro had placed considered and unequal weightings that prioritized the likelihood of the reference case for Energy Prices and for interest rates (represented by the Discount Rate). MIPUG/MH I-3a in the current proceeding reviews the rationale and impact for now using equal weightings. Hydro specifically notes that in the absence of retaining additional outside expertise regarding the energy cost forecasts (as was done with NFAT), "Manitoba Hydro assumed equal weightings to avoid introducing any subjectivity or bias." With respect to interest rates, Tab 4 sets out that interest rates can be modelled using a sample of 50 interest rates from a stochastic interest rate generator[17] but that Hydro elected to use the 3 state model, equally weighted, as it gave relatively similar results with considerably less computing requirements. Figure 4.16 from Hydro's Tab 4 (reproduced

[15] MIPUG/MH I-3a
[16] Manitoba Hydro. 2013. Economic Evaluation Document. Appendix 9.3 of the Needs For and Alternatives To Proceeding. August 2013. Figure 2.15, pg. 60
[17] Tab 4, Manitoba Hydro 2017/18 & 2018/19 GRA, page 20.

below as Figure C-6) sets out a comparison of the two methods to confirm the reasonableness of using the 3 state model rather than the 50 state.

Figure C-6: Projected Equity Ratios from Uncertainty Analyses[18]

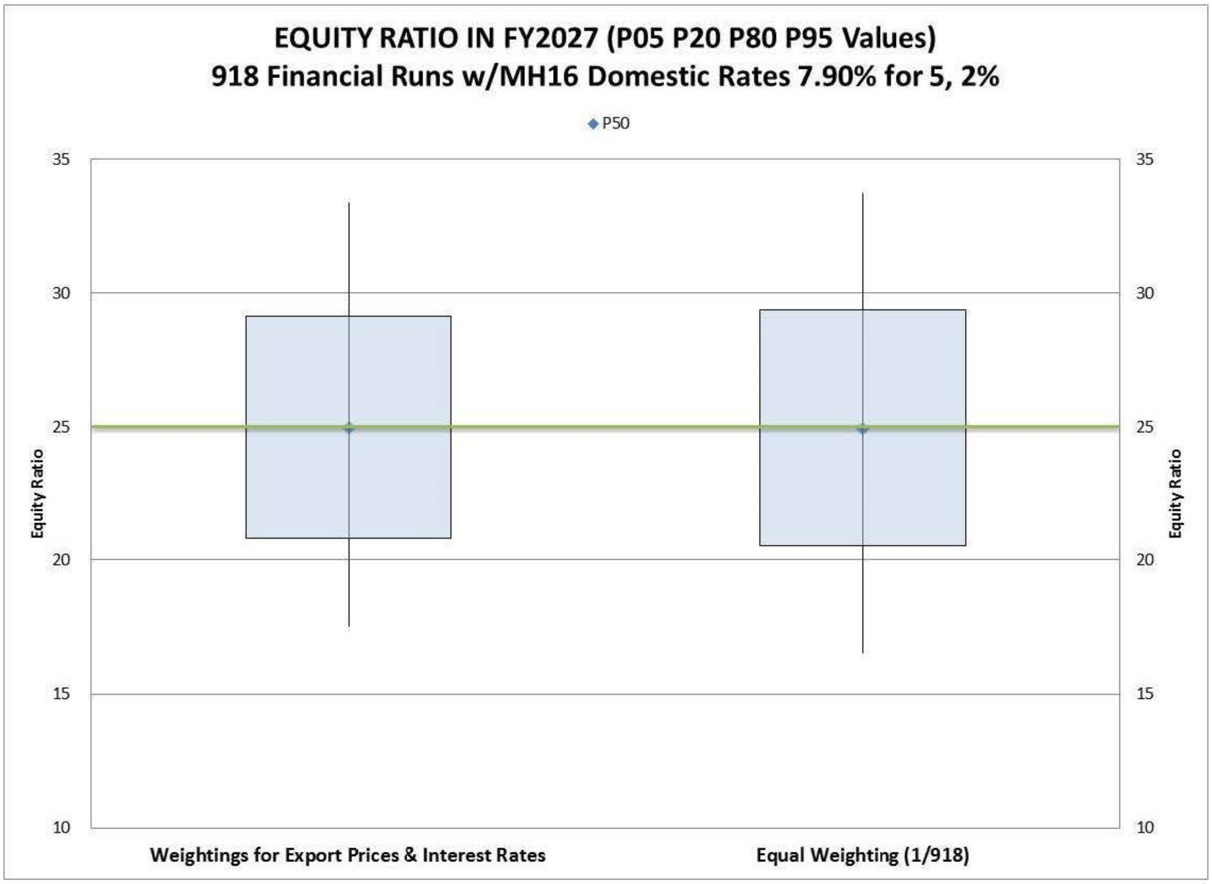


As shown in Figure C-6, the 3 state model (the blue case) does reasonably track the same outcomes as the 50 state model (the brown case), but with a somewhat more pessimistic lean (blue bars and whiskers are lower than brown).

Looking to MIPUG/MH I-3a regarding the combined effect of interest rates and export prices, the figure shown at page 3 of that response illustrates the impact on one sample year and scenario from using a 25%/50%/25% weighting as opposed to a 33%/33%/33% weighting, as reproduced below as Figure C-7.

[18] Tab 4, Manitoba Hydro 2017/18 & 2018/19 GRA, page 21.

Figure C-7: Equity Ratio in FY 2027 (P05 P20 P80 P95 Values)[19]



The above Figure C-7 highlights that little of the box component (the 80th and 20th percentile ranges) is affected by the altered weightings, but that the more extreme ranges (particularly the 5th percentile) is drawn into a notably more constrained range.

Combining the above information, it is likely that Hydro's approach to modelling, using only 3 interest rate projections from the stochastic model rather than 50, and using 3 equally weighted export prices rather than a weighting more similar to the NFAT scenarios, likely results in a small tendency of the cones to be wider (i.e., exhibit more sensitivity) than would otherwise be the case, and the extreme low 5th percentile values in particular to be lower than might otherwise be the case. While the effect is likely measurable, it is unlikely to be materially skewing the output of the uncertainty analysis in a manner that requires immediate action.

Further future improvements to the uncertainty modelling may plan to investigate more refinement in the weightings used, as an incremental improvement.

[19] MUIPUG/MH I-3a, Manitoba Hydro 2017/18 & 2018/19 GRA, page 3 of 9.