Tab #	Description	Reference
Corporate Overview, Need for Requested Increase		
01.	*Letter of Application*	***Tab 1***
02.	*NFAT Proceeding*	***NFAT Report June 2014, excerpts; Electric GRA 2015 MH Exhibit #45, Attachment 1; KPMG Report – NFAT Proceeding, p. 34; 2017/18 & 2018/19 GRA, Appendix 4.5, excerpts***
03.	*BCG Engagement / Rate Request*	***PUB MFR 72 (Revised); PUB MFR 72 – Attachment, excerpts; Tab 2, excerpts***
04.	*CEO Letters in Annual Reports*	***2015/16 Financial Report, p. 7-9; 2016/17 Financial Report, p. 9-13***
05.	*Q2 2017 Financial Update*	***Transmittal Letter dated November 16, 2017; MHEB Quarterly Report – Q2 2017***
06.	*Rate Increases*	***PUB MFR 21; PUB/MH I-3 (a), p. 2; PUB/MH I-3 (b); PUB/MH II-3 (a-b) 2015/16 GRA; MIPUG/MH II-3 (a-b); Order No. 80/17, p. 14; PUB/MH II-47 (Revised) IFF16 Updated - MH Rate Increases 2003/04 to 2018/19; PUB/MH I-152 (b)***
07.	*Conawapa G.S. Costs*	***PUB/MH I-22 (a-b); PUB/MH II-12 (a-c), p. 2-3; PUB/MH II-12 (d)***
08.	*Integrated Financial Forecasts*	***MH14, 2015/16 & 2016/17 GRA, Appendix 3.4; MH15–2016/17 Supplemental Application; Financial Information MFR 1 – Alternate Scenario; Supplemental Filing to MH's GRA 2015/16 & 2016/17, excerpts; IFF – DER & Rates 75% Debt Equity Ratio***

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09.	*2016/17 3.36% Interim Rate*	***2017/18 & 2018/19 GRA Appendix 6.6, p. 1;*** ***MHEB 65th Annual Report, p. 72-74;*** ***Net Export Revenue 2016/17 & 2017/18 – Tables;*** ***Order No. 59/16, p. 4***
10.	*MH16 Forecasts & Scenarios*	***2017/18 & 2018/19 GRA Appendix 3.3 – MH16 20 Year Outlook;*** ***2017/18 & 2018/19 GRA Appendix 3.6 – MH16 Update;*** ***2017/18 & 2018/19 GRA Appendix 3.7 – MH16 Update PUB Scenario;*** ***2017/18 & 2018/19 GRA Appendix 3.8 – MH16 Update with Interim;***
11.	*2017/18 3.36% Interim Rate*	***Supplement to Tab 3, p. 20;*** ***Supplement to Tab 3, p. 7-8;*** ***Tab 2, p. 24***
12.	*Q2 2017 Update on Hydrology*	***Transmittal Letter dated November 16, 2017;*** ***2017/18 & 2018/19 GRA, Appendix 7.4 (Updated), p. 2***
13.	*Reasons for Rate Increase*	***Tab 2, p. 11-12***
14.	*NFAT Hearing Presentation & Transcript*	***MH 2015 GRA – Overview & Reasons Presentation;*** ***NFAT Financial Panel Presentation March 19, 2014;*** ***NFAT Transcript March 19, 2014***
15.	*MH16 & MH16 Update Changes*	***PUB MFR 10 / PUB MFR 10 (Updated)***
16.	*MH16 Forecasts Alternative Rate Trajectory*	***2017/18 & 2018/19 GRA Appendix 3.4 – MH16 20 Year Outlook at MH15 Projected Rate Increases;*** ***2017/18 & 2018/19 GRA Appendix 3.8 (Revised) – MH16 Update with Interim;*** ***PUB/MH I-34 – Attachment 2;*** ***PUB/MH II-25 (a-b)***
17.	*IFF with MH16 Update*	***COALITION/MH II-19;*** ***MIPUG MFR 5***

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MANITOBA HYDRO

2017/18 & 2018/19 GENERAL RATE APPLICATION

LETTER OF APPLICATION

IN THE MATTER OF: *The Crown Corporations Public Review & Accountability Act*

An Application by Manitoba Hydro for an Order of the Public Utilities Board Approving Increases to Electricity Rates

TO: The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

Manitoba Hydro hereby applies to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to *The Crown Corporations Public Review & Accountability Act* for the following:

1. Final approval of Order 59/16 which approved, on an interim basis, an across-the-board rate increase of 3.36% effective August 1, 2016, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to the conclusion of this proceeding;

2. Approval, on an interim basis, of rate schedules incorporating an across-the-board rate increase of 7.9% to all components of the rates for all customer classes to be effective August 1, 2017;

3. Approval of an across-the-board rate increase of 7.9% to all components of the rates for all customer classes to be effective April 1, 2018;

4. Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14, and approval of new LED rates for the Area and Roadway Lighting class (Sentinel Lighting) as discussed in Tab 9 of this Application;

5. Approval to remove the Area and Roadway Lighting (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) from Manitoba Hydro's rate schedule, as discussed in Tab 9 of this Application;

6. Endorsement of modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program ("SEP") that were accepted on an interim basis in Order 43/13, as outlined in Tab 9 of this Application;

7. Final approval of all SEP interim *ex parte* rate Orders as set forth in Tab 10 of this Application, as well as any additional SEP *ex parte* Orders issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

8. Final approval of CRP *ex parte* Order 54/16 as well as any additional *ex parte* Orders in respect of the CRP issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

9. Final approval of Orders 116/12 and 117/12 that approved, on an interim basis, a 6.5% rate increase to the full cost portion of the General Service and Government rates in the four remote communities served by diesel generation effective September 1, 2012, and final approval of diesel zone interim Orders 17/04, 46/04, 159/04, 176/06, 1/10, 134/10, 1/11 and 148/11, subject to confirmation that MKO has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement;

10. Endorsement of the proposed deferral and subsequent amortization of costs incurred with respect to the Conawapa Generating Station project, as discussed in Tab 4 of this Application; and

11. Endorsement of the proposed amortization period for disposition of the regulatory deferral accounts established to capture the differences between Depreciation Expense and Operating & Administrative Expense calculated for financial reporting purposes based on International Financial Reporting Standards, and Depreciation Expense and Operating & Administrative Expense calculated for rate-setting purposes reflecting PUB directives in Order 73/15. Further details are discussed in Tab 4.

As part of its Application, Manitoba Hydro is requesting that the PUB approve a 7.9% rate increase on an interim basis effective August 1, 2017. This will result in an increase of $6.88 in the monthly bill of a residential customer without electric space heat, using an average of 1,000 kilowatt-hours ("kWh") per month, and an increase of $13.14 in the monthly bill of a residential customer with electric space heat, using an average of 2,000 kWh per month. Manitoba Hydro is also requesting the PUB approve a further 7.9% rate increase effective April 1, 2018. This will result in a further increase of $7.43 in the monthly bill of a residential customer without electric space heat, and a further increase of $14.19 in the monthly bill for a residential customer with electric space heat.

Approval of the rate increases proposed in this Application is required to improve the financial position of the corporation. In making this Application, Manitoba Hydro has considered customer sensitivity to rate increases as well as the financial position of the corporation, and believes that the proposed rate increases provide an appropriate balance between addressing the financial risks of the corporation and managing the impact of rate increases on customers.

The circumstances giving rise to the rate increases will be discussed in Tab 2 of the Application. Further information in support of the Application will be provided in Tab 3 to Tab 11.

Communication related to this Application should be addressed to Manitoba Hydro in the following fashion:

Manitoba Hydro
Attention: Patricia J. Ramage
22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Telephone No. (204) 360-3946
Fax No. (204) 360-6147
E-Mail: pjramage@hydro.mb.ca

DATED at Winnipeg, Manitoba this 5th day of May, 2017.

MANITOBA HYDRO

"ORIGINAL SIGNED
BY PATRICIA J. RAMAGE"

Per: ______________________
Patricia J. Ramage

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The Public Utilities Board

Report on the **N**eeds **F**or and **A**lternatives **To (NFAT)**

Review of Manitoba Hydro's Preferred Development Plan

June 2014

Gas generation is not a preferred alternative to Keeyask, as it is at least $339 million less economic than the plan recommended by the Panel. While short-term capital costs may be lower, ongoing operating costs are higher, and the lifetime of gas turbines is only approximately one-third of that of a hydroelectric facility. This means a gas turbine of comparable size would have to be replaced twice during the lifetime of the Keeyask Project. The operating costs of a gas facility include the price of natural gas, which is volatile and forecast to increase from current decade-low prices. The burning of fossil fuels also creates significant greenhouse gas emissions, contradicting the Province's Clean Energy Strategy. Furthermore, the pursuit of the All Gas plan would not support the Minnesota Power export contract, which could lead to a loss of the 750 MW U.S. interconnection.

There are significant benefits associated with the 750 MW interconnection that go beyond the pure economics of the underlying export contract. Currently, Manitoba is interconnected with the MISO market through 1,950 MW of transmission capacity. An additional 750 MW interconnection provides increased electric reliability to Manitoba through additional capacity for imports in times of drought or infrastructure outages. The increased transmission capacity also opens new potential markets in the United States to Manitoba Hydro.

Similarly, wind power is not currently a preferred alternative to Keeyask. On its own, wind power is variable and requires backup capacity, either through a gas plant or hydraulic storage. While Manitoba Hydro's future cost projections for wind power are excessively conservative, wind power is currently less economic than other alternatives.

K. Financial Evaluation and Rate Impacts

All plans analyzed by Manitoba Hydro will require significant rate increases for a period of at least 20 years. Given the need to construct new generation by no later than 2024 and to repair or replace existing infrastructure, an approximate doubling of rates by 2032 is seen by Manitoba Hydro as inevitable. By 2032, Manitoba Hydro's projected increase in rates varies from 82% to 125% for different plans. This means that an average electricity bill in 2013 could double by 2032.

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 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.

While some ratepayers have the option of switching to gas heat if electricity gets too expensive, this option is not available to many other Manitobans to whom gas is not available. These customers will be especially affected by rising rates, as they are dependent on electricity to meet their heating needs.

The Panel is particularly concerned about the impact the projected rate increases will have on lower income consumers, as it heard a substantial amount of evidence about the impact of electricity rates on the lower income segment of the population. This includes customers living in First Nation communities. Manitoba Keewatinowi Okimakanak (MKO) advised that in its First Nations 86% of accounts are currently in arrears, which signals significant affordability issues. However, to a large extent, cost increases can be mitigated by aggressive DSM, which can lead to overall savings.

While ratepayers will shoulder a significant rate burden over the next 20 years, the Province of Manitoba will reap substantial incremental revenues through capital tax and water rental payments from Manitoba Hydro as a result of the Keeyask Project. The Province should give serious consideration to using some of these incremental revenues to fund energy affordability programs targeted to vulnerable consumers, particularly lower income consumers and customers residing in northern and First Nation communities. This could involve rate relief programs as well as targeted DSM programs.

L. Economic Risk Factors

i. Capital Cost Uncertainty

Manitoba Hydro prepares Capital Expenditure Forecasts (CEFs) on an annual basis. Since CEF08, prepared in 2008, the capital cost projections for the Keeyask Project and Conawapa Project have increased in successive annual forecasts. At the start of the NFAT, Manitoba Hydro's capital cost projection was $6.2 billion for the Keeyask Project

ELECTRIC GENERAL RATE APPLICATION 2015

Manitoba Hydro Undertaking #4

Manitoba Hydro to request ministerial approval to file letter to Public Utilities Board regarding the NFAT Report recommendations.

Response:

The Corporation has received consent from the Minister responsible for Manitoba Hydro to file the letter of July 2, 2014, from the Province of Manitoba to the Manitoba Hydro-Electric Board and Manitoba Hydro with respect to the Public Utilities Board's recommendations on the Needs from and Alternatives To Review.

Please find a copy of this letter attached.

GLORIOSUS · ET · LIBER

MINISTER RESPONSIBLE FOR MANITOBA HYDRO

Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

JUL 0 2 2014

Mr. William Fraser
Chair
Manitoba Hydro-Electric Board
7 Kronstal Place
Winnipeg MB R2G 3J8

Mr. Scott Thomson
President and CEO
Manitoba Hydro
P.O. Box 815 Stn Main
Winnipeg MB R3C 2P4

Dear Mr. Fraser and Mr. Thomson:

The Public Utilities Board (PUB) Panel submitted its Report on the Needs For and Alternatives To (NFAT) review of Manitoba Hydro's Preferred Development Plan to Government on Friday, June 20, 2014. We appreciate the significant work and commitment of all Panel members in completing this important review process. The NFAT review was the most thorough financial and economic evaluation of a major industrial development in Manitoba history.

As noted by the PUB Panel, early decisions to develop our Province's rich hydro-electric resources have resulted in many decades of affordable, reliable and renewable electricity for Manitoba families and our growing economy. In more recent times, Manitoba Hydro has greatly enhanced its development model by forging meaningful Aboriginal partnerships over the course of many years, resulting in better environmental stewardship and important socio-economic opportunities and benefits for Aboriginal people. Moving forward, we remain committed to this approach of partnership and reconciliation with Aboriginal people through environmental and resource management, and community and economic development.

We are pleased that the NFAT review has recommended building the next generation of hydro-electric development. The PUB Panel has concluded that new hydro generation is needed in order to meet Manitoba's own power needs and to take advantage of profitable export opportunities. By helping to pay down the cost of new generation, new power export agreements help keep rates low for all Manitobans for the long-term.

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Specifically, the NFAT review has recommended proceeding with immediate construction of Keeyask to meet domestic and export requirements with an advanced in-service date of 2019. Keeyask will be built within the Split Lake Resource Management Area and developed as a ground-breaking partnership between Manitoba Hydro, Tataskweyak First Nation, York Factory First Nation, War Lake Cree Nation and Fox Lake Cree Nation, creating more than 8,000 person-years of employment.

We note that in reaching this favourable recommendation on Keeyask, the NFAT review has concluded that an all-gas alternative would not be acceptable, as it would be significantly less economic and produce greater greenhouse gas emissions than hydro-electric power. The PUB Panel also noted that natural gas would not support Manitoba Hydro's firm sales contract with Minnesota Power, putting those export revenues at risk, along with new transmission to the United States. Building early to take advantage of export opportunities – as was done successfully with Limestone – is a proven strategy for keeping rates low.

The NFAT review has also recommended constructing the new Manitoba - U.S. Transmission Interconnection for a 2020 in-service date. The PUB Panel concluded that this project will add value from an economic and financial perspective by enabling expanded power exports from Manitoba Hydro to U.S. customers. Additionally, the PUB Panel noted that the project will benefit Manitoba Hydro's customers within the Province by strengthening the reliability of our power system, adding greater export and import capability and protection during periods of drought or emergency.

We note that the Obama Administration has cited this international transmission project as an important part of "building a 21st century infrastructure" and that the U.S. Department of Energy has committed to work closely with the lead U.S. proponent, Minnesota Power, and state regulators to move the project through the regulatory approval process. These are positive developments that further underscore the immense opportunity that comes with expanding our access to export markets.

The NFAT review has also made important recommendations on the need to move forward with a new integrated resource planning process, with effective public input, to properly assess future resource options. The energy market is evolving rapidly, and we agree that so too must long-term energy forecasting and planning. Emerging sources of renewable energy are becoming more competitive, demand side management (DSM) programming is being tailored to consumer trends, technological innovation is continuing at a rapid pace, and new U.S. emissions standards are changing historic market dynamics. We accept the PUB Panel's recommendation on the need for a new integrated resource planning process, including proper consideration of DSM, and over the next few months we will work with Manitoba Hydro to prepare an implementation plan for this process. We also agree that this process should be undertaken prior to moving forward with other major capital projects beyond Keeyask and the new Manitoba - U.S. Transmission Interconnection.

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With respect to Conawapa and associated transmission upgrades, Manitoba Hydro has been clear that a decision to proceed is not required at this time. While Manitoba Hydro's contract for a 308 MW power sale to Wisconsin Public Services (WPS) is dependent on building Conawapa, more time is available and required to finalize additional power sale arrangements to strengthen the business case for more power resources.

We note also that following the conclusion of the NFAT hearings, the U.S. Environmental Protection Agency (EPA) released new greenhouse gas emissions standards for the power sector. These standards are widely expected to put greater pressure on utilities in Manitoba Hydro's customer jurisdictions to replace aging coal-fired generating stations with renewable sources of energy. This recent development, in combination with the new Manitoba - U.S. Interconnection, has great potential to open up even larger export market opportunities for clean energy resources, like Conawapa and DSM, as customers look to secure clean, reliable power to diversify their energy portfolios and manage their exposure to environmental issues.

Our Government continues to regard Conawapa, located within the Fox Lake Resource Management Area, as a vitally important component of Manitoba's energy future with the potential to create 10,000 person years of employment and produce far-reaching opportunities for Aboriginal engagement and northern development. However, following from the NFAT review, it is clear that more time is required to secure additional profitable export sales in order to build a stronger business case to justify moving forward with Conawapa and other energy resources beyond Keeyask. We therefore accept the need to freeze expenditures planned for pre-construction work on Conawapa at this time. As additional export sales are confirmed and a stronger business case is developed, a further independent review of Conawapa can be undertaken in the future.

You have advised that Manitoba Hydro remains confident in its ability to secure additional profitable export sales, to justify a stronger case for additional future resource development. We understand that further to recent Memorandums of Understanding (MOUs) negotiations are progressing with both SaskPower and Great River Energy and that new talks are scheduled to begin with long-time customer, Northern States Power, for additional power resources after 2020.

You have also advised us that there are certain activities that are currently underway which relate to Conawapa but which also have broader and enduring value to the corporation, to local communities and to the environment. These include technical environmental studies and analyses required to preserve knowledge gained through extensive fieldwork and Aboriginal traditional knowledge (ATK) studies that help to shape local community development and resource management plans. We agree with you that these limited in-progress activities should be continued, as they are consistent with the Clean Environment Commission's emphasis on the importance of attaining the highest standards of environmental stewardship and continuing to work toward reconciliation with Aboriginal peoples. Carrying on with this limited set of activities will allow Manitoba Hydro to capture the value of many years of work that would be lost if they are halted mid-stream and will protect the corporation from exposure to higher costs in the future if this work has to be re-started from scratch.

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We also urge Manitoba Hydro to continue to review Conawapa construction cost estimates, with the benefit of 'real-time' experience from Keeyask, and make every effort to identify efficiencies as part of ongoing work that will be required for integrated resource planning.

The NFAT review has made a number of significant conclusions respecting Manitoba Hydro's assessment and delivery of DSM programming. Manitoba Hydro has a history of strong leadership in this area and the corporation's new 15-year Power Smart Plan represents a substantially enhanced commitment to DSM programming. Nonetheless, the PUB Panel has expressed concern about current long-term DSM planning, and about the way in which DSM is compared to supply side resources, concluding that a new independent DSM entity should be established. We accept the recommendation that a new DSM entity be established arm's length from Manitoba Hydro, and over the next few months we will investigate different organizational models to strengthen DSM and provide expanded opportunities for all Manitobans to lower their hydro bills. Affordable electricity for Manitoba families and businesses must remain a central component of Manitoba's overall affordability advantage.

In the interim, we are requesting that the Manitoba Hydro-Electric Board oversee a special priority initiative to develop and implement without delay enhancements to DSM programming in areas identified as priorities in the NFAT review, including special outreach to low income families, Aboriginal and northern communities and customers presently excluded from eligibility due to overdrawn accounts. These enhancements should build on recent improvements to Manitoba Hydro's Affordable Energy Program which take a community-based approach to retrofitting homes in low-income communities and on the Aki Energy program, which is lowering bills on First Nations by switching homes from electric heat to geothermal. These models have the additional benefit of creating skills training and job opportunities for local residents – benefits which the NFAT review has suggested should be better accounted for. The Manitoba Government will also consider the Panel's specific recommendation respecting Government revenues from new hydro development, as well as potential alternatives to support vulnerable consumers to reduce their bills.

The NFAT review has also raised the unique needs of large industrial power users. In response we request that Manitoba Hydro advance measures such as curtailable rates and load displacement programs which meet the needs of large power users like manufacturers and resource industries that create jobs and grow our Province's economy.

Also consistent with the PUB Panel's advice we request that the Manitoba Hydro-Electric Board review its current 75/25 debt-to-equity ratio 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 strong financial performance and low rates for all Manitoba Hydro customers.

Finally, we note that the PUB Panel has highlighted the significant load growth associated with expected crude oil pipeline expansion. Given the magnitude of these demands there may be merit in considering a special rate design for these customers. We would ask that Manitoba Hydro consider this issue and prepare recommendations if appropriate.

In conclusion, we are pleased to be proceeding immediately with construction of Keeyask and a new Manitoba - U.S. Transmission Interconnection grounded in firm power sales to the United States. This development model will support lower hydro rates for Manitoba families and businesses for years to come creating jobs, training, investment and growth opportunities throughout our Province and laying the foundation for a new generation of northern development. DSM will be strengthened to help Manitobans reduce their hydro bills and a new more comprehensive integrated resource planning process will be undertaken to chart Manitoba's energy future. Manitoba Hydro will prioritize the finalization of additional export contracts needed to strengthen the business case for further resource development beyond Keeyask so that Conawapa and other resources can be reviewed again in the future.

Sincerely,

Stan Struthers

Stan Struthers
Minister

NFAT Proceeding

In the NFAT proceeding following the above Final Order, the PUB noted as Recommendation 13:

> "The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases." [21]

Elsewhere in the same report, the PUB noted:

> "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." [22]

Summary Discussion

In reviewing the statements made by the PUB above, it is important to recognize that a major challenge associated with MH's financial targets is that actual results will tend to fall short of these targets during periods of major investment. This reflects MH's reliance on retained earnings for growth in its equity base. Thus, the PUB's statement that the 75/25 debt/equity ratio should be relaxed could be interpreted simply as a practical recognition that this target will not be met during a period of large capital expenditures and when newly constructed assets are placed in service.

Accordingly, the 75/25 target could remain the long-term objective. The short-term question is then how large a short-fall can be allowed in the interim. In this respect, the Board expressed concern in an earlier rate proceedings regarding an increase in debt to 90% of capital. Thus, in the body of its Final Order following the 2013 rate proceeding, the PUB wrote:

> "The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by the end of the decade, there will be an insufficient retained earnings reserve to deal with droughts and other risks such as infrastructure failure or rising interest rates." [23]

The above quotation is consistent with a desire to minimize the risk that Manitoba Hydro will face financial distress, which is an important objective in the setting of financial targets. It also suggests that it would be helpful to have some guidance regarding how much deviation is appropriate in any circumstance.

4.2.5 Requirement for risk analysis

Inherent in the setting of financial targets is the need to analyse risk. Since a key objective of targets is to ensure that the corporation has adequate reserves to avoid financial distress, it is important to quantify the magnitude of the risks that could give rise to such distress. Risks are likely to grow in a period of large capital expenditures. The PUB has noted:

> "The Board notes that Manitoba Hydro shares the benefit of the flow-through credit rating of the Province, which affords it preferential interest rates on its debt and access to funds to meet its major capital spending program. However, as its debt grows, there is a potential for Manitoba Hydro's

[21] NFAT Final Report, June 20, 2014, p. 36.

[22] NFAT Final Report, June 20, 2014, p. 29.

[23] Manitoba PUB, Order No. 43/13, April 26, 2013, p.23.

1.3 Summary of the May 2015 Report Recommendations

It should be noted that the updates contained herein have not changed the core recommendations of the May 2015 Report. For greater certainty, we still concur with the recommendations of the May 2015 Report.

The context for the recommendations in the May 2015 Report included the following:

- Relative to other Crown utilities with a significant base of hydro-electric generation, Manitoba Hydro faces a number of heightened risks:
  - Manitoba Hydro has a large capital investment program relative to its current installed asset base and its projected revenues going forward.
  - Manitoba Hydro faces relatively greater hydrology risks than other major utilities.
  - Manitoba Hydro relies on export markets for a significant proportion of its revenue.
  - Utility debt and utility assets in Manitoba are relatively high on a per capita basis compared to other jurisdictions. Manitoba Hydro thus has a relatively limited customer base over which to spread potential future cost overruns or business set-backs.
- As shown through benchmarking, Manitoba Hydro's target equity ratio is at the low end of those maintained or forecast by other government-owned power utilities.
- Manitoba Hydro has limited ability to restrain a drop in financial ratios during adverse conditions, such as a drought. This highlights the risk of having an equity ratio that approaches 10%. For this reason, we believe that equity ratios of 15% or higher are the minimum that should be accepted even for short periods.
- Manitoba Hydro is dependent on an accumulation of retained earnings to build up its equity base. The Manitoba government does not expect to receive dividend income from the utility but nor does it make equity injections during periods of major capital expansion. As a consequence, Manitoba Hydro has few levers with which to adjust its financial position.
- Manitoba Hydro's capital investment program is characterized by periodic "bumps" or "hills" of large magnitude. These fluctuations magnify the challenges associated with Manitoba Hydro's limited levers for financial control.

As further context to this update, the recommendations of the May 2015 Report are repeated below:

Recommendation 1: debt/equity ratio target of 75/25 to 70/30

- Manitoba Hydro's current debt/equity target of 75/25 is a reasonable long-term target. Notwithstanding this finding, we note that a target of 70/30 would provide additional financial strength to address the utility's unique financial challenges and risks. Accordingly, our overall recommendation is that the debt/equity ratio should fall within the range of 75/25 to 70/30.
- Manitoba Hydro will need to depart from its equity target during major build programs: this reflects the utility's limited financing tools and reliance on retained earnings as its dominant source of equity. Accordingly, the equity position should rise above 25% in advance of major build programs to mitigate the deviations from target that are observed.
- We have significant concerns that an 11% equity level, as forecast under IFF14, provides a less than desirable equity base to accommodate potential adverse developments. We suggest that Manitoba Hydro's plans be adjusted to maintain an equity ratio no lower than 15% under forecast conditions during the peak periods of its major capital build program when equity ratios are at their lowest levels.
- In the long-term, with respect to deviations from any target, it would be desirable to limit decreases in the equity ratio to 5-10 percentage points.

- In the long-term, higher equity ratios need not translate into higher rates, because Manitoba Hydro has the option to seek lower rates of return on equity than investor-owned utilities.

Recommendation 2: minimum EBITDA interest coverage ratio target of 1.8 or greater

- As noted in the May 2015 Report, the debt/equity ratio should remain the primary measure of Manitoba Hydro's financial position. An interest coverage ratio is an important element of financial targets and indicator of trends. EBITDA is a widely accepted financial measure and is closer to a cash flow metric than EBIT, albeit with limitations since it does not incorporate capital expenditure requirements or working capital adjustments.
- Our recommendation is an EBITDA interest coverage ratio, at a minimum target level of 1.8 or greater.

Recommendation 3: maintain a minimum capital coverage ratio target of 1.2 or greater

- The capital coverage ratio is also an important financial target and a unique measure to Manitoba Hydro.
- The current minimum target of 1.2 or greater is reasonable in that the corporation should be able to fund its sustaining base capital from current operations without accessing external sources of financing. However, an inherent limitation of this ratio is that it does not reflect the financial challenges associated with major expansion programs. Hence it may be misunderstood or misinterpreted by stakeholders.

Recommendation 4: other metrics to continue to monitor

- Manitoba Hydro should maintain three Financial Targets.
- Manitoba Hydro should also continue to regularly monitor other financial metrics. These include but are not limited to: revenue growth, controllable operating costs, EBITDA, net income, cash flow from operations to net debt, net debt to assets, EBITDA to revenue, capital expenditures to fixed assets, average electricity prices across different customer groups.

In the context of this review, we note that the financial position of Manitoba Hydro has deteriorated in recent years, which increases risk to the corporation and to the Province of Manitoba. Benchmarking comparisons to peer government-owned power utilities show Manitoba Hydro in a relatively worse financial position than comparisons in the May 2015 Report. The Province of Manitoba has experienced credit downgrades from two credit rating agencies since the May 2015 Report. Thus, a return to minimum equity ratio targets, which is fundamental to the financial health of the corporation and the need for a sufficient equity cushion, has increased. With Manitoba Hydro's reliance on retained earnings for equity, the need for growth in sustainable positive cash flow and net income to increase equity has increased. Further, actions at other utilities confirm the importance of a robust equity ratio to support capital expansion and to provide protection against downside risks.

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PUB MFR 72 (Revised)
Corporate Overview

Copies of all Boston Consulting Group's reports, presentations, scope of work, retainer, and correspondence to the MHEB.

The Boston Consulting Group ("BCG") Report and engagement details can be found at the links below:

- Boston Consulting Group (BCG) Bipole III, Keeyask and Tie-Line Executive Summary (September 21, 2016): http://www.hydro.mb.ca/corporate/news_media/pdf/bcg_report_bipole_III_keeyask_and_tie_line_project.pdf
- Boston Consulting Group (BCG) Report of Bipole III, Keeyask, and Tie-Line Project (September 21, 2016): http://www.hydro.mb.ca/corporate/news_media/pdf/bcg_bipoleIII_keeyask_and_tie_line_review.pdf
- Boston Consulting Group (BCG) Engagement Details (November 5, 2016): http://www.hydro.mb.ca/corporate/news_media/pdf/boston-consulting-group-engagement-details.pdf

Update:

The following Letters of Engagement were entered between Manitoba Hydro and the BCG:

- June 2, 2016 letter from BCG to Manitoba Hydro Re: BCG support for Keeyask and Bipole 3 assessment;
- July 12, 2016 letter from BCG to Manitoba Hydro Re: BCG support for Keeyask and Bipole 3 assessment;
- September 13, 2016 letter from BCG to Manitoba Hydro Re: BCG support for US Tie Line assessment.

The following materials were provided by the Boston Consulting Group to the MHEB and/or the Capital Sub-Committee of the MHEB:

- Boston Consulting Group, July 5, 2016 Project Heartbeat Appendix documentation – July 5 draft for internal review;
- Boston Consulting Group' July 6, 2016 Project Heartbeat Board Review –July 5th Sub-Committee Draft;
- Boston Consulting Group, August 9, 2016 Project Heartbeat Interim Checkpoint;
- Boston Consulting Group, August 9, 2016 Project Heartbeat Interim Checkpoint – Appendix;
- Boston Consulting Group, August 22, 2016 Project Heartbeat Capital Sub Committee Review – August 25 BoD Draft;
- Boston Consulting Group, August 22, Heartbeat workout plan Appendix;
- Boston Consulting Group, August 25, 2016 Project Heartbeat Board Meeting readout;
- Boston Consulting Group, October 11, 2016 Tie Line Economics review Capital Sub Committee.

These materials represent the substantive information provided by BCG to the MHEB and /or the Capital Sub Committee of the MHEB. Due to relevance and volume, preliminary working papers in Manitoba Hydro's possession have not been filed.

Manitoba Hydro staff were directed to provide BCG with access to any and all materials, including commercially sensitive information, necessary for BCG to complete their review. Manitoba Hydro staff met with and were interviewed by members of the BCG team during the course of BCG's review. While Manitoba Hydro's President was copied on materials prepared by BCG to demonstrate direction and progress, these materials were not prepared for the purpose of assisting or advising Manitoba Hydro staff nor were they intended to be disclosed in a public forum. Manitoba Hydro staff did not, in the ordinary course, have access to the BCG materials except to such extent information was exchanged for the purposes of obtaining staff comment or accuracy review.

The following report was requested by Manitoba Hydro's President for management review:

- Boston Consulting Group, October 4, 2016 Tie Line Economics Review - Management meeting;

Following receipt of this information, Manitoba Hydro requested BCG prepare a similar presentation for the Capital Sub Committee of the MHEB, which presentation is noted above (Boston Consulting Group, October 11, 2016 Tie Line Economics review Capital Sub Committee).

Manitoba Hydro has provided these materials in order to be responsive to the PUB's MFR request. The primary purpose of retaining BCG in 2016 was to advise the MHEB whether the major capital projects could be stopped and assess the downside risk of completing the projects. The MHEB concluded that the projects should proceed. The purpose of the current review is to approve rates in the context of those projects proceeding. Phase 2 of the engagement dealt with strategies to "weather the storm". While these materials include a discussion of rate related topics, Manitoba Hydro staff were not provided these materials and they were not relied upon in developing the rate application. As such, Manitoba Hydro does not plan to call BCG as a witness in these proceedings. As noted in Tab 2, in 2017 Manitoba Hydro reviewed the key assumptions and undertook an updated financial analysis in order to provide the MHEB with robust analysis in support of the revised Control Budget. Manitoba Hydro staff are in a position to respond to inquiries regarding this most current analysis, not the 2016 BCG analysis.

The materials referenced above can be viewed in chronological order using the following link:

https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/general_rate_application_2017/mfrs/pub_mfr_72_attachments.pdf

Public disclosure of portions of the documents attached in response to this MFR would result in the release of information considered to be confidential and commercially sensitive. Manitoba Hydro has redacted such commercially sensitive information from these documents. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

BCG

June 2, 2016

Mr. Dave Brown
Board Director
Manitoba Hydro
360 Portage Ave
Winnipeg, Manitoba
R3C 0G8, Canada

Re: BCG support for Keeyask and Bipole 3 assessment

Dear Dave,

Thank you for the opportunity to support you in assessing the Keeyask and Bipole 3 projects.

Contained within this letter are the following sections:

- Scope of work
- Team and working arrangements
- Our standard terms

SCOPE OF WORK

Two projects, Keeyask and Bipole 3, represent ~$11B in capital spend (with additional spend tied to interdependent projects, e.g., Minnesota and Great North). You have four overall questions you would like answered "in the next 30 days"

- How sound was the original rationale for the projects?
- Can the projects be stopped without undue risks or "breakage" costs?
- What is the downside risk if the existing project scope is run to completion?
- What viable alternatives exist to maximize value?

We propose addressing these questions across the following 6 modules:

1. **Was the risk framework appropriate as rationale for these projects?**
    - Keeyask: Domestic demand profile and risk of supply interruption without Keeyask to provide generation capacity and access to U.S. sources; Consideration of other factors evaluated at the NFAT review
    - Bipole 3: Reliability risk of not doing Bipole 3 and reasonability of risk; Costs/risks of alternatives to Bipole 3 to protect reliability
    - Have there been material changes since projects were approved?
2. **What are the costs and risks of stopping/pausing each of the projects?**

- Quantification of what is committed, ramp-down & sustainment cost (and optimal timing)
- Contract assessment of stoppage penalties (eg PDA, EPC)
- Interdependencies with other projects, e.g., Manitoba-Minnesota, Great North
- Impact of failing to meet social commitments, e.g., political, labour, First Nations

3. **What are the expected market economics of the capital program?**
    - Export scenarios, based on, contract prices and opportunity sale prices, e.g. Clean Power Plan, U.S. market prices (in MISO), inter-provincial demand (Saskatchewan)
    - Contract ladder and counterparty risk
    - Bearer of load risk per de facto regulatory policy (i.e. Manitoba Hydro vs. rate payers)

4. **What is the risk of cost and or schedule overruns for Keeyask and Bipole 3?**
    - Control budget assessment (e.g., costs, reserves, scope, contingencies)
    - Delivery model assessment (e.g., E&C contract / risk, PM/CM capabilities)

5. **What is the expected financial impact of these project scenarios, including stopping?**
    - Cash flow projections, incl. ramp up timing and operating cost assumptions
    - Balance sheet and/or rate impacts
    - Potential impact on 'affordability' of other sustaining capex

6. **What alternative options are available to optimize cost/risk and upside potential?** (Initial top-down, qualitative assessment only)
    - Opportunities to maximize commercial potential (Keeyask only)
    - Potential for capital project redesign, e.g., descoped, staged rollout, better execution

We would propose tackling these questions over 4 week period plus 1 week of upfront ramp up.

- In Week 0 (May 30-June 3), we will align on scope and deliverables, refine work plan, assemble the team, launch the data request, lock-in Board dates, and schedule other key meetings
- In Week 1 & 2 (June 6-June 17), we will focus on building the core of the fact base represented by modules 1-4 described above
- In Week 3 & 4 (June 20-July 1), we will shift focus to synthesizing our findings into the financial and laying out the options for moving forward

We would propose 2 meetings with the Board sub-committee and 1 meeting to review findings with the full Board

- First sub-committee meeting to review interim findings following fact base phase (w/o June 20)
- Second sub-committee meeting to review synthesis and options (w/o June 27)
- Final review with the Board (at already scheduled July 6 / 7 meetings)

TEAM AND WORKING ARRANGEMENTS

Execution of this project will be led by Andrew Loh. Kilian Berz (with his leadership role in Canada) and David Gee (with his leadership role as the North American Practice Area Leader for Energy) will both provide senior leadership support. These members of the team shall comply with Hydro's personal risk assessment requirements. In addition, they will be supported by 2 full time project managers, Warrick Lanagan and Laszlo Korsos, both principals at BCG. Warrick is BCG's Global Topic Leader for large capital project management (LCPM) and Laszlo is an industry specialist with deep generation modeling experience.

Summary biographies for the core leadership team are as follows:

Kilian Berz, Senior Partner and Managing Director (Toronto)

- Former Managing Partner of BCG Canada, leading expansion into 3 new industry verticals and 4 new provinces
- Active experience in Manitoba, bringing understanding of Provincial dynamics
- Extensive experience with Canadian Crown Corporations
- Over 20 years of consulting experience
- Leads BCG research on innovation and growth clusters in Canada

David Gee, Partner and Managing Director (Washington, DC)

- Energy Practice North American Leader
- 37 years of experience in energy
- Former President NA for AES (13GW generation) ; Chairman of IPL and Trans-Elect
- Former VP Strategy at PG&E
- Extensive utility transformation experience

Andrew Loh, Partner and Managing Director (Toronto)

- Canadian Utilities Topic Leader
- Over 16 years of consulting experience
- Leading end-to-end transformation of Canadian T&D utility
- Extensive experience leading strategy and transformation for Utilities, Engineering & Construction, Mining & Metals industries
- Extensive experience with Canadian Crown Corporations

Warrick Lanagan, Principal (Toronto)

- NAMR topic expert for Large Capital Project Management
- Experience with large capital project scoping, optimization and turnaround
- Experience with utility transmission and distribution capital portfolios
- Core member of Energy, Industrial Goods and Operations teams
- 8 years' experience with BCG

Laszlo Korsos, Principal (San Francisco)

- 10+ years Energy experience in Europe and U.S. with focus on generation modeling, distributed generation, regulation, and growth strategies

- Global Utility Transformation Expert
- Supported development of 100% renewable plan for Hawaii and complete transformation program

The core leadership team will be supported by 4 full time Consultants.

The weekly cost of this team is [redacted] in professional fees plus [redacted] at our standard rates. In the spirit of developing a new partnership, we propose investing in this first phase of work. The Week 0 ramp up week (May 30-June 3) would be fully invested by BCG. The cost of the remaining 4 weeks (June 6-July 1) would be [redacted] at our standard weekly rates. We would also propose investing 50% of our fees and rolling these funds into a potential Phase 2. In other words, if we decide to work together on a second phase of work, the cost of this phase would be only [redacted] (calculated based on standard professional fees). This amount will be invoiced on July 1. If you decide not to move forward with a second phase within 120 days from the completion of this first phase, we will invoice you for the balance of the full [redacted]
The amounts payable by you for the services to be provided are exclusive of all value added tax or other similar tax which (if applicable) shall also be paid by you. You shall pay all amounts payable under this letter agreement free and clear of all deductions or withholdings unless the law requires a deduction or withholding. If a deduction or withholding is required by law, you shall make such withholding and pay such additional amount unless we) provide you with the documents that would allow us to claim a reduced rate of tax or exemption from tax in accordance with the applicable double tax treaty with respect to any withholding taxes required to be borne by us under this letter agreement.

We look forward to having the opportunity to serve the Board of Manitoba Hydro on this critical effort.

Sincerely,

Kilian Berz

Kilian Berz	David Gee	Andrew Loh
Senior Partner & Managing Director	Partner & Managing Director	Partner & Managing Director

* * * * *

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

Summary of key messages we will walk through today

1. **Original decision on Bipole III justifiable but Keeyask (in hindsight) a less prudent decision**
   - Bipole III East was lowest-cost option to address longstanding, untenable reliability risk but was refused an environmental permit
     – Of remaining options, Bipole III West lowest cost vs. All gas and Import + gas
   - Keeyask (with US Tie-line) long-run economics attractive on paper, but financial and execution risks not fully considered
     – Rationale existed for accelerating Keeyask, e.g.: sustainable energy solution that capitalizes on expiring export opportunity
     – However, several factors suggest decision imprudent, e.g.: lower / delayed capex alternatives (e.g. gas) not fully explored, costly constraints not fully challenged, permits not in place ahead of proceeding, discount rates did not reflect project risk
   - Imprudence can be traced to systemic decision governance issues, e.g.: lack of clear objective function and criteria/constraints of Hydro and regulatory body, rates not linked to allowable returns, iterative (vs. upfront) approach to investment decisions

2. **Based on current outlook, project economics expected to worsen and remain sensitive to key uncertainties**
   - Capital execution will likely overrun and export price assumptions expected to worsen (outside of carbon constrained scenario)
   - Equity ratios dip to single digits - similar to 1970-1995, but Province with 30%+ net debt/GDP vs. ~20% before

3. **Despite these challenges, cancelling in flight projects to shift to alternatives is not a realistic option**
   - ~$5B already sunk on Bipole III and Keeyask with cancellation costs of ~$1B each, bringing effective total to ~$7B
   - ~$2.9B cost to complete Bipole III <u>West</u> clearly more favourable vs. ~$4.5B rerouting costs of Bipole III <u>East</u>
     – Furthermore, decision to reroute Bipole III would strand Keeyask, making it uneconomic and likely trigger cancellation
   - ~$6.7B cost to complete Keeyask yields an NPV $3-5B more favourable vs. switching to gas option, and avoids strategic risks

4. **Range of levers for a "workout" program to mitigate the impact of projects in a continuation scenario, e.g.**
   - Improve the projects: Manage capex risk, fully exploit Keeyask / Tie-line commercial opportunity
   - Strengthen core business to ease impact of projects: OM&A efficiency, deferral of low value capital projects
   - Grow equity base: Raise rates, reduce gov't payments, inject gov't equity, sell select assets/project equity
   - Moreover, Province needs to address systemic governance issues, e.g., objective function and criteria/constraints of Hydro and Regulator, rate regime linked to allowable returns, system investment plan approval process

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Updated

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PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

4 Summary: What can been done to mitigate impact of continuing?

Highly preliminary values for directional purposes only ($100M retained earnings = ~30-40 bps equity)

	Potential Levers	Base Value:	Realistic 5-year change	Impact on retained earnings
4a Improve the projects	Implement LCPM (schedule review, lean design, construction productivity)	-	Reduce $1.4-1.6B expected overrun across two projects	Not yet quantified
	[redacted]	[redacted]	[redacted]	[redacted]
4b Strengthen the core business	Launch OM&A efficiency program	$542 M	Hold nominal flat for 5 years (~10% cumulative real reduction)	$ 150 M
	Optimize debt maturity to reduce Finance Exp.	$571 M	Reduce average maturity profile of debt from 20 years to 12 years	$ 150 M
	Defer low value capital projects	$577 M	$100 M annual reduction	$ 100 M
4c Grow equity base	"Negotiate" for higher rates (R&SB and industrial)	3.95% annual	5% annual increases on average across the board	$ 300 M
	Revise structure of provincial payments	$317 M	Deferral of capital taxes, and guarantee fees linked to Keeyask and Bipole III until in-service date	$ 200 M
	Structure equity transfer	$0 M	$ 500M one-time payment upfront	$ 600 M

In addition, Province needs to address systemic decision governance: Objective functions, rate regime, investment plan approval process

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4c Rating agencies outline key drivers indicating Manitoba Hydro's self-sustaining status

Drivers of self-sustaining status	Current environment	Future risks
Ability to raise customer rates above current levels	✓ Lowest electricity rates in Canada enable sustainability of rate increases	? Sustained rate increases jeopardize MB law requiring lowest cost bundle of regulated rates
Political will to support required rate increases	✓ PUB a reasonable regulator that has raised rates when required in past • 45 of 47 rate cases resulted in requested increases	? Tolerance for sustained rate increases above 4% untested • Latest rate case only approved 3.36% increase vs. 3.99% request
Opportunities to reduce capital spending if required	✓ MH has ability to defer non-critical sustainment CapEx short-term	✗ Sustainment CapEx deferrals likely to lead to future backlog requiring higher CapEx to clear

Rating agencies assessing both Manitoba's provincial and Manitoba Hydro debt status

Source: Credit rating reports, Manitoba Hydro, BCG analysis

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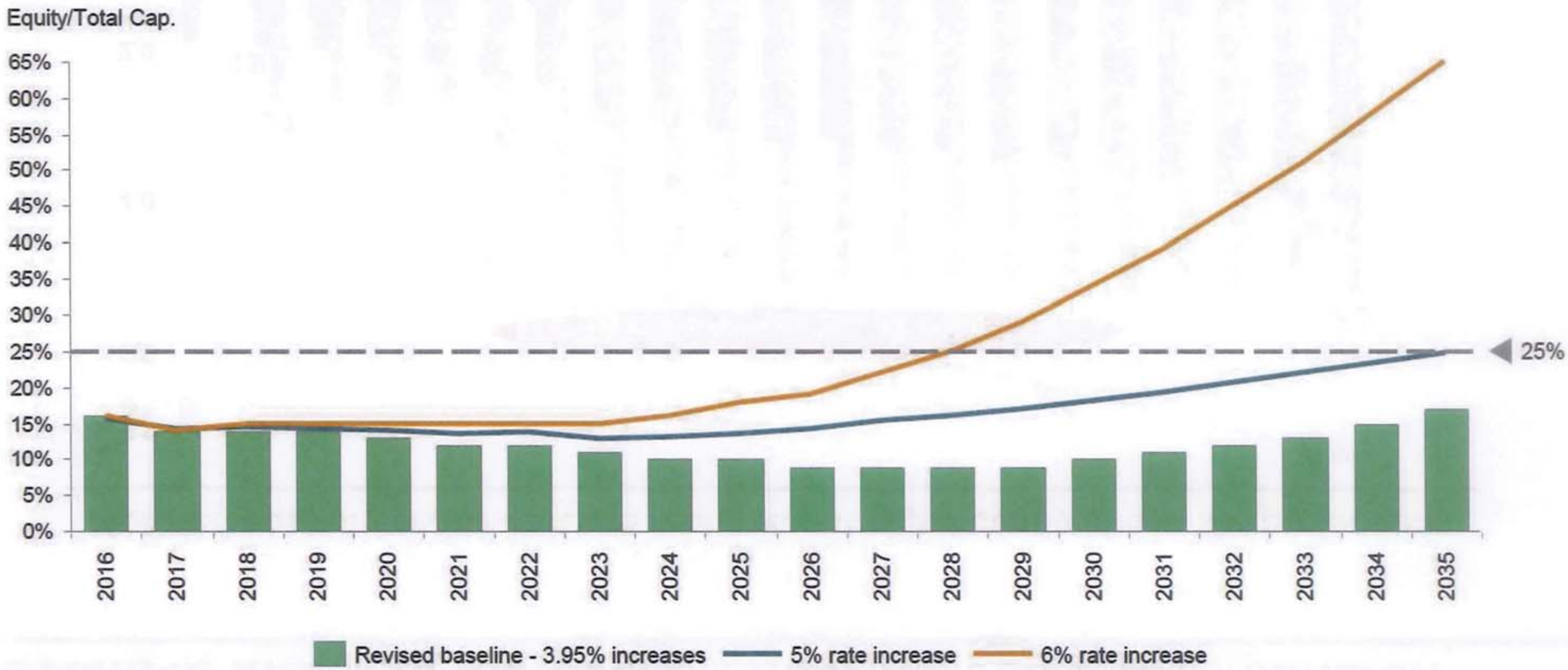
Expected cost overruns prevent achievement of 25% equity target by end of forecast period without higher rates

4c

Expected 3.95% increases, along with capital overruns and delays, lead to long period of below-target equity ratios



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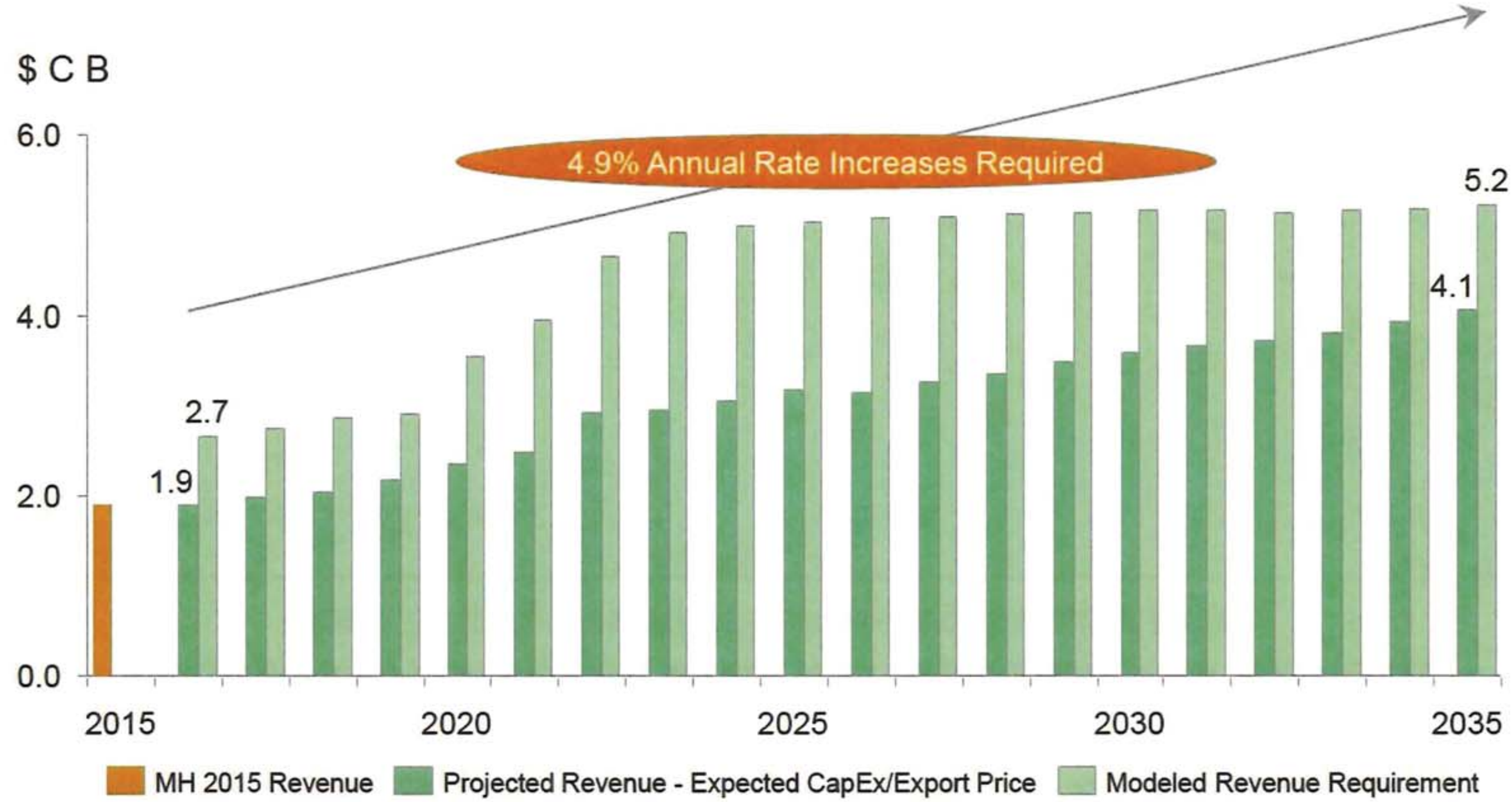
Under cost of service, MH would receive significantly higher (4c) revenues and rate increases timed with capital expansion

Modeled cost of service revenue requirement significantly above MH projections



The rate increase to immediately get to a cost of service level would be 50% - resulting in ~10 cents per kWh rates

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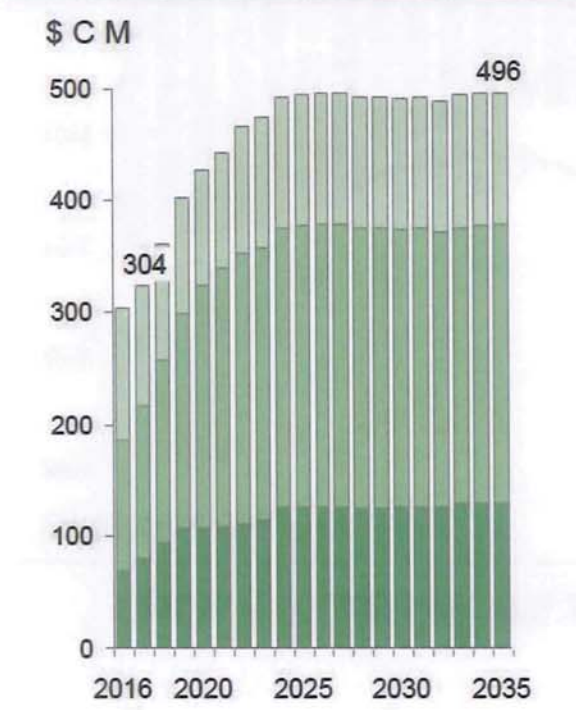
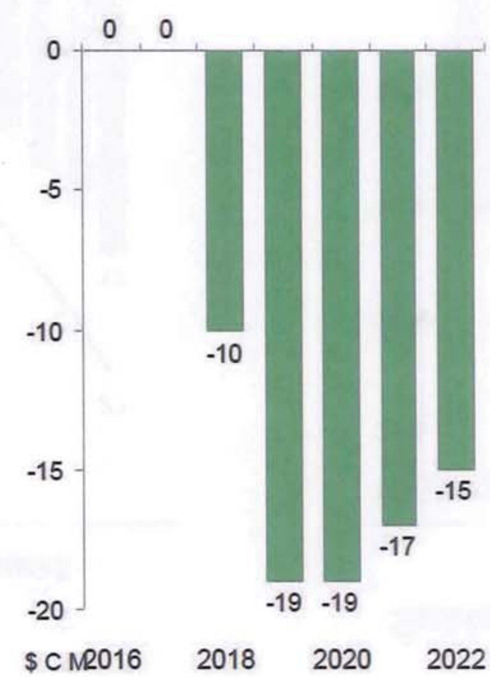
4c Impact of Provincial Payment Deferral

Provincial Payments
Revised Baseline Scenario

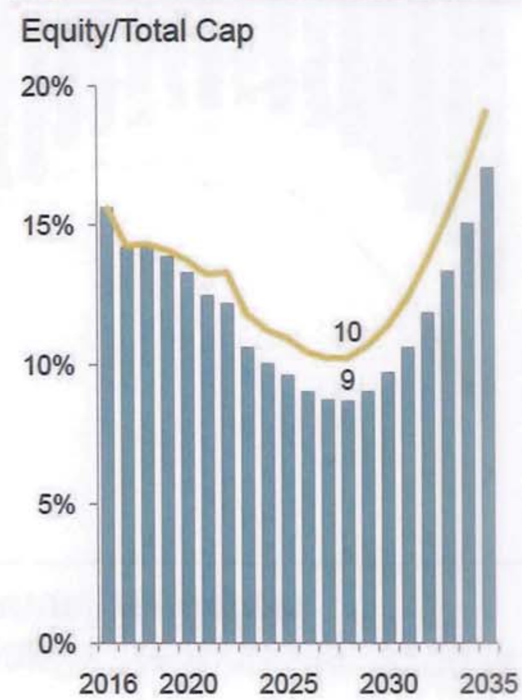


Initial Capital Tax Impact



Water Rentals · Provincial guarantee fees · Capital Taxes

Equity ratio impact



Equity ratio - deferred provincial payments
Equity ratio - baseline with low export prices

Source: Manitoba Hydro, BCG Analysis

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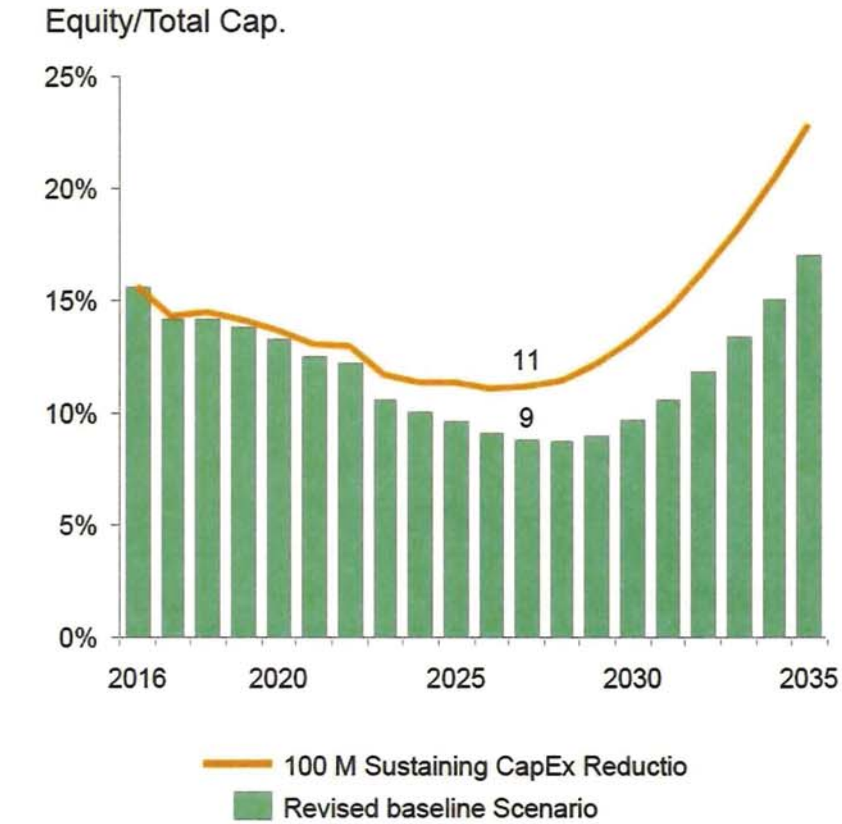
4c Equity ratio impact of OpEx and Sustaining CapEx Reduction

OpEx Reductions: 0% increases

Sustaining CapEx Reductions: $100 M Annual reduction



Source: Manitoba Hydro, BCG Analysis

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BCG

July 12, 2016

Mr. Kelvin Shepherd
President & Chief Executive Officer
Manitoba Hydro
360 Portage Ave
Winnipeg, Manitoba
R3C 0G8, Canada

Re: BCG support for Keeyask and Bipole 3 assessment

Dear Kelvin,

Thank you for the opportunity to support you in developing the path forward plan for the Keeyask and Bipole 3 projects to ensure a financially stable Manitoba Hydro.

Contained within this letter are the following sections:

- Scope of work
- Team and working arrangements
- Our standard terms

SCOPE OF WORK

In our initial 4-week engagement, we addressed the following 4 questions:

- How sound was the original rationale for the projects?
- Can the projects be stopped without undue risks or "breakage" costs?
- What is the downside risk if the existing project scope is run to completion?
- What viable alternatives exist to maximize value?

Coming out of this engagement we agreed that, regardless of the original rationale, the projects should continue, but with a plan that protects the economic viability of both Manitoba Hydro and the Province (as guarantor of the debt).

The immediate scope of this "Phase 2" engagement is to align the Board and Management along the following dimensions:

- Capital requirement to "weather the storm" (e.g., 5-year, 10-year) and long-term target equity ratio
- Quantification of what can be done "on our own" (e.g., improving the projects economic and risk profiles, strengthening the core business)
- Action required of the Province to "fill the gap", i.e., appropriate balance of ratepayer contribution (e.g., support of rate increase plan) or taxpayer contribution (e.g., equity injection)
- Communication narrative and stakeholder management plan to address these immediate issues and longer-term governance issues (Manitoba Hydro-led)

We propose addressing these questions across the following 5 modules:

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

We see 5 modules for next 6 weeks

To meet August Board meeting objectives

	Core focus	Lead advisor
1 Capital project assurance and improvement	1A Integrated project schedule review 1B Rescoping and value optimization opportunity assessment	BCG
2 Core business improvement	2A OM&A efficiency diagnostic: Size of prize and key levers 2B Sustaining capital portfolio review: Investment optimisation	BCG
3 Domestic and extra provincial revenue	3A Domestic revenue scenarios (e.g., thresholds, segmentation) 3B Export revenue realization (e.g., higher % firm)	BCG
4 Balance sheet	• Capital requirement to weather the storm • Scenarios of different mixes of levers, eg – rates v provincial payments – revenue enhancement opportunities	BCG
5 Communication and stakeholder mgmt plan	• Overall narrative • Customization by audience, e.g., Internal, Public, PUB, ratepayers, intervenors, etc.	Manitoba Hydro

Will also require coordinating body to ensure synthesis of many moving parts, i.e., PMO

THE BOSTON CONSULTING GROUP Draft—for discussion only 3

Modules 1-3 would be led by BCG (working closely with management). Module 4 would also be led by BCG but with heavy input expected by the investment banking advisors (TD Securities and Barclays), particularly on level of capitalization requirements and trade-offs to debt treatment and debt ratings of various equity injection options. Module 5 would be led by Manitoba Hydro, drawing on the synthesis of findings of the first 4 modules.

We would propose tackling these questions over a 6-week period plus 1 week of a Phase 0 ramp up.

- In Week 0 (July 11-15), we will align on scope and deliverables, refine work plan, assemble the team, launch the data request, lock-in Board dates, and schedule other key meetings
- In Week 1-3 (July 18-August 5), we will focus on building the baseline. This will include the level of capitalization required, current project schedules, people spend breakdown, procured spend breakdown, existing sustaining capital plan, domestic rate and export contract history and forecasts, regulatory frameworks and constraints, etc.
- In Week 4-6 (August 8-26), we will shift focus to developing benchmark-based estimates of value potential to improve the projects (e.g., costs, revenue potential, and risk profile) and strengthen the core business. We will assess the tradeoffs of scenarios to fund the balance of the equity gap through rates vs. equity injection and put forward a recommendation.

We would propose 2 meetings with the Board sub-committee and 1 meeting to review findings with the full Board

- First sub-committee meeting to review interim findings following baselining (w/o August 8)
- Second sub-committee meeting to review quantification of opportunities and relative impacts/tradeoffs of scenarios (beginning w/o August 22)
- Final review with the Board (end w/o August 22)

TEAM AND WORKING ARRANGEMENTS

Execution of this project will be led by Andrew Loh and Warrick Lanagan. Kilian Berz (with his leadership role in Canada) and David Gee (with his leadership role as the North American Practice Area Leader for Energy) will both provide senior leadership support. The members of the team shall comply with Hydro's personal risk assessment requirements.

The core leadership team above will be supported by 3 Project Managers and 8 full-time Consultants.

The weekly cost of this team is [redacted] in professional fees [redacted] at our standard rates. In the spirit of continuing to invest in our relationship, the ramp up week (July 11-15) would be fully invested by BCG. The cost of the remaining 6 weeks (July 18-August 26) would be [redacted] at our standard weekly rates. Per what we agreed in our prior engagement, we will discount the cost of our original engagement by 50%, or [redacted], given we are moving forward with a second phase. Therefore, the effective cost of this second phase is [redacted]

The amounts payable by you for the services to be provided are exclusive of all value added tax or other similar tax which (if applicable) shall also be paid by you. You shall pay all amounts payable under this letter agreement free and clear of all deductions or withholdings unless the law requires a deduction or withholding. If a deduction or withholding is required by law, you shall make such withholding and pay such additional amount unless we) provide you with the documents that would allow us to claim a reduced rate of tax or exemption from tax in accordance with the applicable double tax treaty with respect to any withholding taxes required to be borne by us under this letter agreement.

We look forward to having the opportunity to serve the Board of Manitoba Hydro on this critical effort.

Sincerely,

Kilian Berz	David Gee	Andrew Loh
Sr. Partner & Managing Director	Sr. Partner & Managing Director	Partner & Managing Director

* * * * *

Phase 2: Summary of key messages

Hydro needs to close $3.8B funding gap near-term and target 25% equity longer-term to maintain economic stability

- During capital expansion phase, must be able to service debt in downside case
- Downside case indicates $3.8B fund gap which, if left unaddressed, puts economic self sustainability at risk
- Over the longer-term Hydro should target ~25% equity comparable to Crown utilities to weather business volatility in expected case
- Expected case indicates Hydro does not achieve target equity until 2035+

5-year "workout program" developed with balanced contribution from 3 areas to close $3.8B funding gap

- Manitoba Hydro: Up to $0.8B ($275-525M in efficiency, $300M in capital project mitigation)
- Ratepayers: Up to $0.8B (Manitoba policy thresholds imply up to 9.3%/year for 5 years vs. current trajectory of 3.95%)
- Province: Can close remaining gap of $2.4B by
  - Taking DSM off balance sheet: $450M (by 2021)
  - Forgiving Provincial payments for 5 yrs – water rental, capital tax, debt guarantee – or similar capital injection: Up to $1,900M

In addition to closing $3.8B funding gap, "workout program" would accelerate meeting 25% target equity from 2035 to 2022

- Creates "surplus" equity position which can be used to maintain investment grade rating, issue government dividend, and/or fund future capital projects

Communication narrative needs careful articulation to instill confidence in Gov't, Board, and Mgmt to fix past mistakes

- First version of narrative required early September to avoid further delay on Bipole 3
  - Emphasis on: Deteriorated economics/timelines, decision to move forward with projects as-is, balanced workout program
- "Final" version of narrative required early October to address broader set of stakeholders and get ahead of GRA process with PUB
  - Details of workout program, implications for policy direction on rates and longer-term regulatory governance

5-year "workout program": Sources to close $3.8B funding gap

Up to $0.8B from Manitoba Hydro, up to $0.8B from ratepayers, up to $2.4B from Province

		Description	Peak run rate equity impact: By 2021 ($M)	Cumulative equity impact: 2016-2021 ($M)
Manitoba Hydro Efficiency, Capital projects, Revenue enhancement	Efficiency: Sourcing	Competitive bidding, spec rationalization, demand management opportunities	40-75	125-225
	Efficiency: SG&A	Process efficiency, talent/capacity alignment, role duplication, spans of control, non-essential work	15-30	50-100
	Efficiency: O&M	Optimizing mix to highest return programs, improving labour mix and utilization, improving tool time	30-70	100-200
	Efficiency: Capex	Reduction and/or deferral opportunities (or risk)		Likely not spending enough; required increase in spend TBD
	Capital projects: Keeyask	Mitigating overrun from 32 months to 21 months	N/A	200
	Capital projects: Bipole 3	Mitigating overrun from 15 months to 12 months	N/A	100
	Capital projects: US tie-line	Optimize cost/protect in-service-date		Not yet assessed
	Export revenue enhancement	[redacted]		Limited (and no impact before 2022)
Ratepayers	Domestic	Rate increases aligned to benchmarks and policy thresholds (5-year CAGR 9.3%[3] vs. current 3.95%)	Up to 370	Up to 840
Province	DSM capital program	Move capital off balance sheet; redesign DSM program to complement impact of rate increases	95	450
	Payment forgiveness[1]	5 years of relief from provincial payments (water rental, capital tax, debt guarantee)	Up to 430	Up to 1,900
	Total		**980 - 1,070**	**3,750 - 4,000**

1. Or similar capital injection

Domestic rev.

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

Rate increases to occur within constraints of current framework; reform required for longer-term sustainability

Short term considerations: Rate case filing and policy environment

- MH to apply for **3-year general rate application** in Dec. for Aug. '17 rate increases
  - Workplan suggests up to 9.4% rate increase
  - Application supported by cost of service study
- Framework allows for development of reserves, but offers **little insight as to right levels**
  - Limited guidance on treatment of reserves during periods of capital expansion
- PUB has historically shown **bias towards lower, smoother rate increases**
  - Core intervener community focused on cost allocation, low rates and increasing DSM
- **Premier dictates Provincial energy policy** and has approval authority over major CapEx
  - Province has influence over tenor of rate discussions and PUB composition

Longer-term reform opportunity: Sustainability and alignment of incentives

- **Prepare regulatory reform with MH and PUB** focused on **improving incentive alignment and encouraging long-term sustainability**
- Reform likely a **part of broader Provincial energy policy** and may involve legislative change
- Revised framework to be based on **key principles:**
  - Supporting MH's long-term **financial stability**
  - Establishing **equitable and transparent** rate setting
  - Incorporating input from **stakeholders**
  - Preserving and improving system **reliability**
  - Supporting conservation and **environmental sustainability**

Domestic rev.

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

MH's primary near-term lever to generate income is rate increases; rate design can mitigate impacts of higher rates

Option	Potential outcomes		
Shift in regulatory framework	Status quo modified cost of service model	Hybrid cost of service/ rate of return	Shift to rate base/rate of return
Level of rate Increase *Cumulative over 5 years*	5% CAGR *27% cumulative*	6.5% CAGR *37% cumulative*	9.3% CAGR *56% cumulative*
Pace of rate increase	Gradual (5+ years)		Immediate (1-2 years)
Level of Differentiation	Status quo (uniform rate increases)	GS vs. Residential differentiation to align to cost covg.	Full differentiation to align to cost coverage
Policy stance (e.g. cross subsidization, low income)	Status quo (e.g. DSM for low income)	Gov't-implemented policy (e.g. add'l social transfers)	Implementation by MH (e.g. LI rate credits)
Treatment of export revenues	Used to reduce customer rates	Partial use to reduce debt burden	Used to reduce debt burden

Cumulative increases of >40% provide significant financial strength and bring rates in line with benchmarks

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

Phase 2: Summary of key messages

Hydro needs to close $3.6B funding gap near-term and target 25% equity longer-term to maintain economic stability

- During capital expansion phase, must be able to service debt in downside case
- Downside case indicates $3.6B fund gap whi..., ... unaddres_e_, puts economic self sustainability at ri...
- Over the longer-term Hydro should target ~25% equity comparable to Crown utilities to weather business volatility in base case
- Base case indicates Hydro does not achieve target equity until 2035+

5-_ear "workout _ro_ram" develo_ed with balanced contribution from 3 areas to close $3.6B fundin_ _a_

- Manitoba Hydro: Up to $0.9B ($275-525M in efficiency, $350M in capital project mitigation)
- Ratepayers: Up to $0.8B (Manitoba policy thresholds imply up to 9.3%/year for 5 years vs. current trajectory of 3.95%)
- Province: May need to close remaining gap of $1.9B -$3B

In addition to closing $3.6B funding gap, "workout program" would accelerate meeting 25% target equity from 2035 to 2024

- Creates "surplus" equity position which can be used to maintain investment grade rating, issue government dividend and/or fund future capital projects

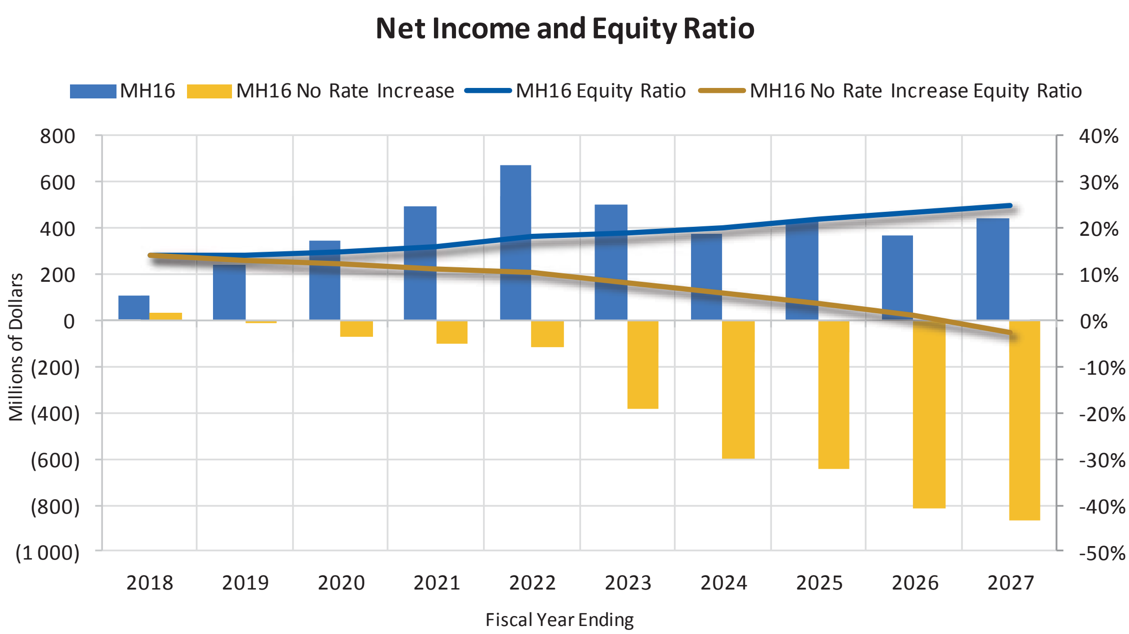
Communication narrative needs careful articulation to instill confidence in Gov't, Board, and Mgmt to fix past mistakes

- First version of narrative required early September to avoid further delay on Bipole 3
  - Emphasis on: Deteriorated economics/timelines, decision to move forward with projects as-is, balanced workout program
- "Final" version of narrative required early October to address broader set of stakeholders and get ahead of GRA process with PUB
  - Details of workout program, implications for policy direction on rates an... ...-term regulatory governance

Master timeline required to co-ordinate multiple streams in the near and mid term

level of net income allows the Corporation to adequately absorb the risks noted above coming to fruition either independently or in combination while still allowing the Corporation to make modest progress on restoring its equity capitalization.

Figure 2.29 Net Income and Equity Ratio with and without Rate Increases



Manitoba Hydro acknowledges past applications and testimony that indicate a willingness to tolerate a relaxation to below 15% equity during the current phase of debt funded capital investment. In past applications, Manitoba Hydro has also proposed a financial plan that would have seen a 15 year time frame for restoring a 25% equity capitalization. The conditions and outlook for Manitoba Hydro has changed significantly since the last GRA as has the Corporation's governance, namely:

i) Since the last GRA, a new Board of Directors (MHEB) has been appointed along with a new President & CEO and a new Chief Finance & Strategy Officer. Together, the MHEB and senior management team have charted a new course for Manitoba Hydro inclusive of a strategic imperative to restore financial sustainability. The MHEB tolerance for risk has changed considerably and therefore a path back to 25% equity of longer than 10 years is, in the view of Manitoba Hydro, too risky;

ii) The control budgets for Keeyask and Bipole III have increased by $2.2 billion and $0.4 billion respectively necessitating further increases in gross borrowing thus exacerbating the strain on the financial plan;

iii) The domestic load growth forecast has significantly deteriorated delaying the need for Keeyask to well into the 2030's and lessening the opportunity for Manitoba Hydro to look to growth to cure its financial challenges;

iv) Export price growth expectations again have been tempered from past forecasts as the outlook for sustained low fossil fuel costs perpetuates; and,

v) 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%. The credit rating of the Province has been downgraded by both major international rating agencies. Inclusive of the Corporation's debt at forecast peak, Manitoba's debt to GDP will reach 65 to 70% of GDP which would put the Province amongst the highest ratios in Canada. The Province has diminished capacity to absorb inclusion of Manitoba Hydro's debt in its consolidated credit profile without risking further erosion of its credit standing.

Manitoba Hydro is taking stronger action to reduce internal costs and improve financial performance to protect the Corporation and the interests of its customers. These cost reductions on their own will not be enough to restore Manitoba Hydro's financial position. Accelerating the magnitude of rate increases over the next five years is thus required; however, this will allow future rate increases to return to levels at or near inflation earlier than previously forecast.

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Working for you

Manitoba Hydro-Electric Board 65th Annual Report
For the Year Ended March 31, 2016

Manitoba Hydro

President & CEO’s Letter to Customers

The theme of this report, working for you, reflects Manitoba Hydro’s focus on serving our customers. We exist for the benefit of Manitobans and are dedicated to meeting your energy needs now and into the future.

An executive by experience, a professional engineer by training, and a prairie farm boy at heart, it was a great honour and privilege to assume the role of President & Chief Executive Officer of Manitoba Hydro in December 2015.

Manitoba has a tremendous advantage generating approximately 97 per cent of its electricity from renewable hydropower.

During my first 100 days on the job, I spent time travelling the province, visiting both Manitoba Hydro and customer operations as well as meeting with key stakeholders. Coming from outside the corporation, my intention was to learn about Manitoba Hydro by listening to employees, customers, Indigenous leaders and many others. In those conversations I heard common themes. Manitobans expect us to be reliable and fair. You expect us to manage our financial and human resources responsibly. There is an inherent understanding of the importance of our relationships with Indigenous communities and the importance of us interacting with the environment in a manner that meets the needs of the present without compromising the ability of future generations to meet their needs.

Conversations with stakeholders also confirmed what I knew to be Manitoba Hydro’s strengths, including a highly skilled and diverse workforce, a level of customer satisfaction that is among the highest in the industry, and an energy system that produces practically all of our electricity from renewable sources. In a world that is increasingly concerned about reducing carbon emissions and transitioning to renewable energy, Manitoba has a tremendous advantage generating approximately

97 per cent of its electricity from renewable hydropower. This is very different from many other jurisdictions in North America where major investments are required to transition away from fossil fuel generated electricity. Aside from providing Manitobans with a reliable source of cost effective electricity, renewable resources also enable the province to be a major exporter of electricity to neighboring jurisdictions generating revenues which help deliver lower rates to our customers here at home.

We also deliver affordable, clean natural gas which provides efficient and cost effective heating to nearly 60 per cent of the homes in Manitoba and is an important energy source for business and industry in the province. Manitobans are currently benefiting from historically low natural gas costs, as Manitoba Hydro flows the benefits of lower prices directly through to our customers.

I've come to appreciate just how committed our employees are to carrying out their responsibilities and fulfilling the important mandate entrusted to us.

Meeting Manitoba's current and future energy needs requires ongoing investment in new capacity coupled with re-investment to upgrade and replace aging infrastructure. The significant investments being made towards ensuring a secure, reliable energy system for Manitobans create financial challenges for the corporation. Successfully addressing these challenges will require us to operate more efficiently but also requires raising additional revenues. We have continued with an approach of seeking moderate, predictable annual increases to electrical rates and in parallel we are doing our part to increase operating efficiency helping us limit increases in our operating and administrative expense to 1% annually, which is less than the rate of inflation. Over the past two years, we have driven cost reductions and reduced our operational staffing levels by taking advantage of retirements and normal employee turnover while continuously seeking to find new efficiencies in how we work.

Since joining Manitoba Hydro, I've come to appreciate just how committed our employees are to carrying out their responsibilities and fulfilling the important mandate entrusted to us. This commitment is most often on public display when we face challenging circumstances – such as when we have a major storm that knocks down lines and disrupts service. Yet, behind the scenes, where you can't always see their efforts, Manitoba Hydro employees work hard on a daily basis to deliver the energy and the customer service you count on.

This company has been and will continue to be successful thanks to the efforts of many who bring their considerable knowledge and experience to bear on the many facets of the corporation. On behalf of the employees of Manitoba Hydro, I would like to take this opportunity to thank the outgoing members of the Manitoba Hydro-Electric Board (MHEB) for the time and energy they dedicated to serving the energy needs of Manitobans.

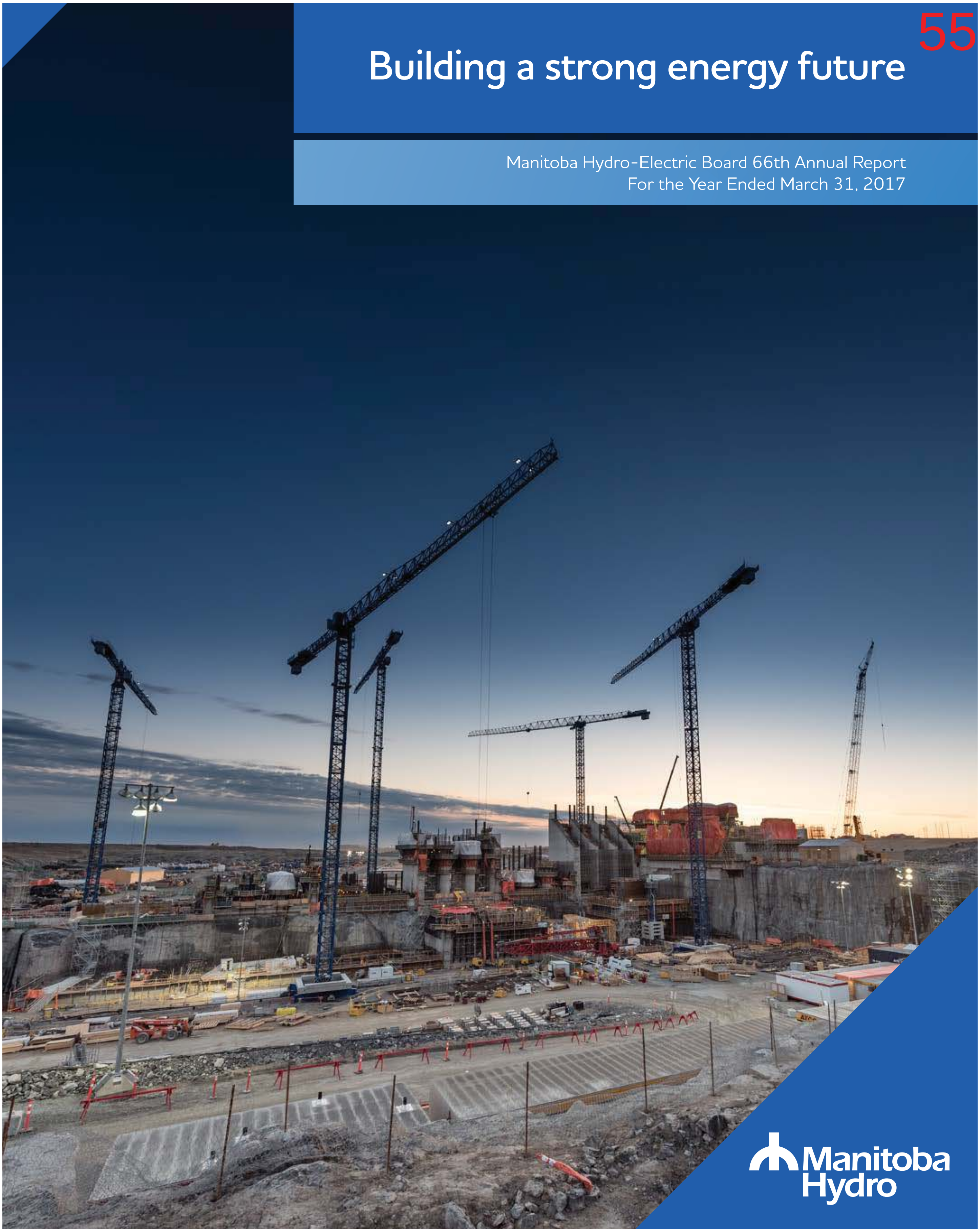
I would also like to welcome the new MHEB members. Recognizing the mandate and direction given to the board by our new government, we are fully committed to working hard to ensure that together we set the right future direction in order to best serve Manitobans.

At Manitoba Hydro we remain wholeheartedly dedicated to having positive impact on the lives of our customers and on the prosperity of our province. We are committed to safely, reliably and affordably delivering the energy you count on. We are working for you.

Kelvin Shepherd, P.Eng
President and Chief Executive Officer
Manitoba Hydro

Building a strong energy future

Manitoba Hydro-Electric Board 66th Annual Report
For the Year Ended March 31, 2017



Manitoba Hydro

President & CEO's Letter to Customers

Building a strong energy future

Manitoba Hydro has seen some significant changes over the past year. A new board of directors was appointed in May 2016, and over the next three months they undertook a strategic review of Manitoba Hydro's financial and operating plans including a detailed review of the Bipole III Transmission and Keeyask Generating Station major capital projects. The board's review confirmed that, all factors considered, proceeding with both projects was the right decision for Manitoba Hydro and our customers despite anticipated cost escalations and schedule delays. This decision was not made lightly. In releasing the results of their review, the board expressed serious concerns with the equity position of the corporation as well as other changes in our business outlook; taken together these factors have created significant financial challenges and risk exposure for the corporation.

Our focus going forward must be on completing these major capital projects as quickly, efficiently and safely as possible.

Previous decisions by Manitoba Hydro to build Bipole III while simultaneously advancing the construction of Keeyask will double the corporation's debt in a relatively short time frame. In addition, persistent low prices in the short-term opportunity export market, primarily as a result of shale gas exploration and subsidies for development of wind and solar resources in the United States, combined with lower than forecasted electrical load growth here in Manitoba, are expected to reduce projected revenues by approximately $1.5 billion over the next decade. Adding to the financial implications of this shortfall is a nearly $3 billion projected increase in the capital costs for Keeyask and Bipole III.

The longer western route used for the Bipole III project also increased its cost, however, the project is now urgently required to address significant risks associated with increasing over-reliance on the existing Bipole I and Bipole II transmission links to our northern generation supply. Keeyask, which is being constructed in partnership with four First Nations - Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation - was recognized in the board review as too far advanced to cost effectively defer or cancel the project. In short, cancelling these two major projects would result in billions already invested with no functioning assets to show or available to meet future needs, and a continued reliance on a single transmission corridor for the bulk of our electricity supply. Our focus going forward must be on completing these major capital projects as quickly, efficiently and safely as possible.

To ensure Manitoba Hydro remains a strong, financially sustainable company with long-term capability to provide customers reliable, cost effective service, we are taking immediate actions to begin to restore Manitoba Hydro's financial health.

Keeyask and Bipole III are large, complex undertakings with multiple risks. Following the analysis completed as part of the board's review, and subsequent in-depth study by Manitoba Hydro, revised control budgets and schedules were established. Bipole III is now scheduled to be in-service in August 2018 at an estimated cost of $5 billion, while Keeyask is estimated to cost $8.7 billion with its first unit in service in 2021.

These projects are each among the largest currently under construction in North America and together represent a huge investment financed primarily by debt. As Manitoba Hydro takes on this level of debt, we must ensure there is sufficient cash flow to fund our operations and also to build a reasonable financial cushion of retained equity (through net income) to manage the inherent risks we face as a utility. While Manitoba Hydro's primarily hydroelectric energy supply is renewable with stable operating costs, it does bring with it unique risks including high capital costs, variable export market pricing, exposure to rising interest rates, and real impacts associated with droughts among other weather and system-related issues. Our current rate base isn't adequate to manage these risks into the future.

Manitoba Hydro recorded $71 million in net income for the past fiscal year which was an improvement from the prior year but represents only 35 per cent of the net income recorded 15 years ago when Manitoba Hydro was approximately half its current size. The reality, given the rates being charged to date, is we've already had to borrow several hundred million dollars to fund our core operations, and this is not sustainable over the longer term.

To ensure Manitoba Hydro remains a strong, financially sustainable company with long-term capability to provide customers with reliable, cost effective service, we are taking immediate actions to begin to restore Manitoba Hydro's financial health.

Much of the surplus power available during Keeyask's initial life is already sold to four utilities in Minnesota, Wisconsin and Saskatchewan through firm long-term contracts worth over $4.5 billion.

In May 2017 we submitted a General Rate Application to the Manitoba Public Utilities Board (PUB) which has authority to review and set electricity rates in Manitoba. Our plan includes annual increases to electricity rates in Manitoba of 7.9 per cent in each of the next five years followed by inflationary increases of two per cent annually thereafter. We anticipate the PUB will hold public hearings on the rate application in late 2017 or early 2018, and look forward to engaging in discussions with our customers and other stakeholders about the details of our long term financial plans as part of the rate review process.

We know Manitobans depend on us for their energy and we recognize we are proposing significant electricity rate increases over the next number of years. By increasing rates now we are seeking to protect both our customers and the company from the possibility of much higher rate increases in future if some of the risks that we are concerned about materialize. Our approach seeks to balance asking our customers to pay a higher, but still reasonable price for their energy while providing necessary revenues to ensure the long-term financial health of Manitoba Hydro. Manitoba rates will continue to be very competitive with other jurisdictions where utilities are facing their own challenges associated with aging infrastructure and the need to update and expand energy systems while they simultaneously transition to a lower carbon future.

Our plan also targets a significant decrease in our operating costs through a 15 per cent reduction in our workforce and finding further efficiency in our operations. The initial broad step in our workforce reduction plan included a Voluntary Departure Program offered to the majority of employees. The program will see over 800 employee departures between June 2017 and January 2018. Some additional staffing reductions are anticipated over the next two to three years as we complete Bipole III and undertake other new efficiency initiatives.

We are working to transform Manitoba Hydro into a leaner, more efficient and more customer-focused organization.

We are also working hard to sell any remaining surplus power which will provide additional revenues until our domestic load increases. We continue to explore further sales opportunities with both Canadian and American utilities who have growing requirements to source reliable and renewable energy. Much of the surplus power available during Keeyask's initial life is already sold to four utilities in Minnesota, Wisconsin and Saskatchewan through firm long-term contracts worth over $4.5 billion. The proposed Manitoba-Minnesota Transmission Project, reviewed this spring by the Clean Environment Commission, will provide the additional transmission capacity we need to deliver current and new sales to the United States and will significantly enhance the reliability of Manitoba's energy supply by doubling our ability to import electricity in times of drought or system emergency.

Additional sales are possible not only through arrangements with neighboring utilities but also through finding ways within our mandate, and to the benefit of Manitobans, to enable business development in the province. We were proud to work with Roquette Frères, a global producer of starch and plant-based specialty food ingredients, on an arrangement for energy services that supported their decision to expand into the North American market and locate their major pea-processing facility at the Poplar Bluff Industrial Park location near Portage la Prairie. This is but one example of our work with customers on a daily basis.

We are working to transform Manitoba Hydro into a leaner, more efficient and more customer-focused organization. To that end, reorganization of Manitoba Hydro's executive team and corporate structure was undertaken earlier this year to align the company with four strategic priorities vital to our success going forward – restoring financial sustainability, delivering an excellent customer experience, engaging employees in our transformation, and respecting and supporting Indigenous people in all aspects of our business. Along with our foundational principles of safety, environmental leadership and respectful engagement with communities and stakeholders, our strategic priorities are the cornerstones on which we will build a strong energy future for the province.

Manitoba Hydro continues to have strengths which we will build on. These include being in the enviable position of generating over 97 per cent of our electrical energy from renewable hydropower, operational and cost advantages gained from being a fully integrated gas and electrical utility, and our strong track record of providing safe, reliable energy services to customers.

Over the last year, working with our new board of directors, we have established a strong plan to move forward and have taken the initial steps required to create the positive changes needed to position us for success in the coming years. I am extremely positive about Manitoba Hydro's future and the ability of our organization to meet the challenges in front of us and adapt to the ever evolving energy sector.

I want to thank our employees for their hard work and dedication as well as their continued support as the company moves forward with our plan to become a stronger, more customer-focused organization delivering a strong energy future for all Manitobans

Kelvin Shepherd, P.Eng
President and Chief Executive Officer
Manitoba Hydro

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Manitoba Hydro
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Telephone / N° de téléphone: (204) 360-3946 • Fax / N° de télécopieur: (204) 360-6147 • pjramage@hydro.mb.ca

November 16, 2017

Darren Christle
Executive Director and Secretary
Public Utilities Board of Manitoba
400 – 330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO QUARTERLY REPORT FOR THE SIX MONTHS ENDED SEPTEMBER 30, 2017

On November 13, 2017, Manitoba Hydro announced its consolidated financial results for the six months ended September 30, 2017.

As part of the response to PUB MFR 13 filed on May 12, 2017, Manitoba Hydro provided copies of its financial statements up to and including the third quarter of the 2016/17 fiscal year (9 month period ended December 31, 2016). Enclosed with this letter, Manitoba Hydro is providing an update to PUB MFR 13 and its quarterly reports for the first and second quarters of fiscal year 2017/18. Manitoba Hydro is also enclosing an update to Appendix 7.4 (Directive 5 of Order 43/13) to provide actual monthly hydraulic generation, water conditions and extra-provincial energy exchange data for the month of October 2017.

As noted in PUB MFR 13 (Updated), Manitoba Hydro's forecast consolidated net income for the full 2017/18 fiscal year has decreased to $40 million. The Corporation can advise the PUB that the 2017/18 forecast for the electric segment is approximately $30 million assuming normal system inflows and average winter weather conditions.

This compares to a forecast of $93 million for 2017/18 under MH16 Update with Interim (filed as Appendix 3.8). The principal cause of the 68% reduction in Manitoba Hydro's profit outlook is a precipitous decline in net export revenues. Overall, net export revenues are now estimated to be $210 million in the 2017/18 fiscal year which represents a $58 million or 22% reduction from the assumptions in MH16 Update with Interim.

System inflows since late April were considerably below historical average which has dramatically reduced reservoir levels from near record highs to just above mean. Manitoba Hydro forecasts average water flow conditions for the remainder of 2017/18. Nonetheless generation volume is now expected to be lower than forecast in MH16 Update with Interim leading to an anticipated 11% decline in export volumes (in GWh).

Of further note, PUB MFR 13 (Updated) indicates that opportunity and contract market export prices have fallen significantly short of anticipated levels and have demonstrated minimal appreciation from prior year. As of September 30, 2017, on-peak opportunity prices were 22% below the target in MH16 Update with Interim while off peak prices were 6% below target. This represents a further deterioration compared to the quarter ended June 30, 2017 where on-peak and off-peak prices were 16% and 4% below target.

Manitoba Hydro has not updated its integrated financial forecast; however, it can advise that net export revenues for next fiscal year, 2018/19, are now expected to be $198 million which represents a $12 million decline from the updated forecast for this fiscal year and a $20 million (or 9.3%) reduction from levels assumed in MH16 Update with Interim. Generation volume is still anticipated to be above average in 2018/19 as Manitoba Hydro forecasts beginning the year with higher than average reservoir levels.

MH16 Update was prepared following very high spring run-off and filed as Appendix 3.6 on July 11, 2017. The significant deterioration in outlook since that time is an example of the potential volatility in Manitoba Hydro's short and long-term results due to water levels and export market conditions.

Should you have any questions with respect to the forgoing, please do not hesitate to contact the writer at 204-360-3946 or Greg Barnlund at 204-360-5243.

Yours truly,

MANITOBA HYDRO LEGAL SERVICES DIVISION
Patti Ramage
Barrister & Solicitor

cc: All Approved Interveners
Odette Fernandes, Manitoba Hydro
Bob Peters, Board Counsel
Dayna Steinfeld, Board Counsel

The Manitoba Hydro-Electric Board

Quarterly Report

for the six months ended
September 30, 2017

Report from **The Chair of the Board** and by **The President and Chief Executive Officer**

Financial Overview

Manitoba Hydro's consolidated net loss was $89 million for the first six months of the 2017-18 fiscal year compared to a net loss of $72 million for the same period last year. The increase in the net loss is primarily attributable to restructuring costs driven by the implementation of a significant cost reduction program. Excluding the restructuring expenses, net loss would have been $45 million, an improvement of $24 million over the prior year. The improvement is mostly attributable to favourable water conditions which led to a $32 million improvement in extraprovincial revenues (net of power purchase and water rental expenses) along with $9 million in growth in Manitoba electricity volumes. Higher finance costs and depreciation and amortization expense offset part of these gains. The cost of natural gas is a flow through cost passed onto customers through rates approved by the Public Utilities Board (PUB) and therefore is not a driver for the increase in net loss compared to the prior year.

The consolidated net loss was comprised of a $66 million loss in the electricity segment, a $26 million loss in the natural gas segment, a $2 million net profit in other segments and a $1 million profit impact in adjustments and eliminations.

Manitoba Hydro has seen a significant deterioration in its profit outlook for the 2017-18 fiscal year. The corporation is now forecasting consolidated net income for the year of approximately $40 million. This represents a 44% decrease from 2016-17 net income of $71 million. It also represents almost an 80% drop from our outlook for net income from a reforecast filed with the Public Utilities Board in July. The decrease in forecast is due to the PUB's decision to deny the corporation's request for a 7.9% rate increase as at August 1, 2017, a continuation of weak opportunity export prices, a relatively dry summer impacting water flow conditions and higher financing costs. The forecast assumes average water flow conditions and normal winter weather.

Electric Segment

Revenues from electricity sales within Manitoba totaled $629 million for the six-month period, which was $9 million or 2% higher than the same period last year. The increase in domestic revenue was primarily attributable to an increase in average usage and customer growth, partially offset by weather impacts. Extraprovincial revenues of $275 million were $28 million or 11% higher than the same period last year reflecting higher dependable sales volumes predominantly as a result of higher generation due to favourable water conditions along with modestly higher export prices on opportunity sales. Energy sold in the export market was 6.9 billion kilowatt-hours compared to 6.3 billion kilowatt-hours sold in the same period last year. Other revenues of $15 million were $3 million or 25% higher than the same period last year due to an increase in billable projects for third parties.

Expenses attributable to electricity operations, including the net movement in regulatory deferral balances, totaled $993 million for the six-month period. This represented an increase of $55 million or 6% as compared to the same period last year. The increase was primarily due to a $50 million increase in other expenses, an $8 million increase in net finance expense and a $6 million increase in depreciation and amortization. The increase in other expenses was primarily due to $42 million in restructuring charges associated with the voluntary departure program which launched in April 2017. The increase in net finance expense was primarily the result of foreign exchange losses. The increase in depreciation and amortization was primarily due to new additions to plant being placed into service.

The net loss before net movement in regulatory balances is $113 million. After considering the net movement of $40 million in the regulatory deferral balances, there is a net loss of $73 million of which $66 million is attributable to Manitoba Hydro and $7 million is attributable to non-controlling interest. The non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first six months of the 2017-18 fiscal year.

Expenditures for capital construction for the six-month period amounted to $1 437 million compared to $1 347 million for the same period last year. Expenditures for the current period included $582 million related to construction of the Keeyask project and $573 million for the Bipole III Reliability Project. The remaining capital expenditures were incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The corporation also incurred $31 million for electric demand side management programs.

Natural Gas Segment

The net loss in the natural gas segment was $26 million for the six-month period compared to a $24 million net loss for the same period last year. The increase in the net loss is primarily due to restructuring costs and warmer weather in the first quarter. Delivered gas volumes were 530 million cubic metres compared to 609 million cubic metres for the same period last year.

Expenses attributable to natural gas operations excluding cost of gas sold amounted to $75 million compared to $73 million for the same period last year.

The net loss before net movement in regulatory balances is $39 million. After considering the net movement of $13 million in the regulatory balances, there is a net loss of $26 million.

Capital expenditures in the natural gas segment were $18 million for the current six-month period compared to $26 million for the same period last year. Capital expenditures are related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province. The corporation also incurred $5 million for gas demand side management programs.

Other Segments

The other segments include Manitoba Hydro International Ltd., Manitoba Hydro Utility Services, Minell Pipelines Ltd. and Teshmont Holdings Ltd. The net income was $2 million in other segments for the six-month period compared to net income of $3 million for the same period last year. Revenue was $30 million which was the same as the prior period. Expenses attributable to other segments amounted to $28 million which was $1 million higher than the prior year principally due to foreign exchange losses.

There is also a $1 million profit impact in adjustments and eliminations as a result of the requirement to harmonize accounting policies between electric and natural gas operations related to the gas meter exchange program.

Returning Manitoba Hydro to Financial Health

On July 30, 2017 the PUB awarded Manitoba Hydro a 3.36% interim rate increase, effective August 1, 2017. The corporation's General Rate Application filed with the PUB in May had requested an interim rate increase of 7.9% in August 2017 and a further 7.9% in April 2018.

As a result of the lower interim rate increase, Manitoba Hydro has revised its rate increase targets. The original plan called for a return to financial health over a 10 year period. In addition to accelerated cost reduction goals, the plan envisioned five years of 7.9% rate increases, followed by five years of 2% increases. The revised 10-year plan, inclusive of this year's 3.36% rate award, calls for six years of 7.9% rates increases starting in 2018-19, a 4.54% increase in 2024-25 followed by two years of 2% increases.

The requested rate increases are part of the corporation's plan to restore the utility's financial strength to ensure it can continue to meet Manitobans' energy needs and to keep electric rates lower and more stable for customers in the future. Failing to address Manitoba Hydro's deteriorating financial position in a timely manner substantially increases the likelihood of unexpected and higher rate increases. The 10-year plan includes measures to lower internal operating costs. Already in 2017, Manitoba Hydro has reduced the senior management team by 25% including a 30% reduction to the executive. Since June 1, 325 employees have left the corporation under our Voluntary Departure Program (the VDP) with almost 500 more scheduled to leave by January of 2018. When complete, the VDP will enable close to a 15% reduction in actual staff levels and we anticipate these staff departures will save the corporation over $90 million annually. We are also identifying and aggressively implementing opportunities to manage the business more efficiently and pursuing additional firm sales on the electricity export market.

Without the requested rate increases, the corporation forecasts it will be approximately $800 million short of the cash needed to fund core operations, including investing in the replacement and upgrading of aging infrastructure province-wide, over the next five years. This excludes the cash required to complete the Keeyask Generating Station and Bipole III Reliability Project.

Additional revenue would also help the utility withstand the risks of rising interest rates and drought, and maintain its debt at prudent levels.

A full public hearing before the PUB on Manitoba Hydro's 2017-18 & 2018-19 General Rate Application is scheduled to begin December 4 and end February 9, 2018.

Natural Gas Rate Decrease

In accordance with Manitoba Hydro's methodology to change natural gas rates every quarter depending on the price of gas purchased from Alberta (and as approved by the PUB), rates for residential customers decreased on August 1, 2017 by 4.0% or approximately $29 per year. Rate changes for larger volume customers ranged from decreases of 3.8% to 31.4% depending on the customer class and consumption levels.

The bill impacts are primarily the result of changes in the price that Manitoba Hydro pays for natural gas from Alberta.

Bipole III Reliability Project Approaches Completion

The 1 384-kilometre, high-voltage Bipole III transmission line and the Keewatinohk and Riel converter stations, which link either end of the transmission line, are nearing completion after almost five years of construction.

The transmission line runs from Keewatinohk near Gillam to Riel near Winnipeg and is forecasted to be completed March 31, 2018. The transmission line needs to be ready to use prior to the final in-service date of the stations which is scheduled for July 2018. Two major contractors are working on the transmission line concurrently in northern and southern Manitoba. To maintain completion dates, helicopters are being used for tower installation, hanging of insulators and stringing of conductor wire. Recent milestones include the project reaching two million hours of labour by Indigenous employees and over eight million labour hours in total.

Bipole III will deliver renewable energy to southern Manitoba and will strengthen reliability and security of Manitoba's electricity supply by reducing dependency on the existing HVDC transmission lines and the Dorsey Converter Station.

CNG Filling Station Now in Service

Manitoba Hydro's new compressed natural gas (CNG) station went into service in September. The new station is located on Provincial Road 330 immediately south of the Perimeter Highway in the RM of Macdonald.

The station allows the corporation to provide an alternate supply of natural gas to customers in the event of an outage, such as the fire on TransCanada Corporation's pipeline near Otterburne in January 2014 which left approximately 4 000 homes without natural gas. During the outage, Manitoba Hydro coordinated with TransCanada Corporation and other utilities outside the province to bring CNG in by truck until the pipeline was repaired. However, trucks coming from Saskatchewan were delayed more than three days due to a winter storm. In the interim, many customers purchased electric space heaters to heat their homes. The increased usage put heightened demand on the electrical distribution system.

The CNG station will allow the utility to respond faster to a natural gas outage impacting up to approximately 1 200 customers without threatening the supply of electricity. The station allows two tanker trucks to fill up with CNG and deliver it to local injection points in the natural gas distribution system.

A corporation-owned and maintained CNG station also allows Manitoba Hydro to supply natural gas to customers uninterrupted when conducting repairs and pipeline maintenance on the natural gas distribution system.

H. Sanford Riley

Chair of the Board

Kelvin Shepherd, P. Eng.

President and
Chief Executive Officer

November 14, 2017

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Revenues				
Domestic – Electric	629	620	308	308
– Gas	88	95	34	36
Extraprovincial	275	247	141	142
Other	43	39	22	18
	1 035	1 001	505	504
Expenses				
Cost of gas sold	53	42	19	19
Operating and administrative	303	302	146	148
Finance expense (net)	324	315	160	156
Depreciation and amortization	210	203	105	102
Water rentals and assessments	64	62	32	31
Fuel and power purchased	57	62	26	31
Capital and other taxes	74	69	37	34
Other expenses	99	47	31	26
	1 184	1 102	556	547
Net loss before net movement in regulatory balances	(149)	(101)	(51)	(43)
Net movement in regulatory balances	53	23	27	17
Net Loss	(96)	(78)	(24)	(26)
Net loss attributable to:				
Manitoba Hydro	(89)	(72)	(20)	(24)
Non-controlling interest	(7)	(6)	(4)	(2)
	(96)	(78)	(24)	(26)

Consolidated Statement of Financial Position

In Millions of Dollars (Unaudited)

	As at September 30	As at March 31	As at September 30
	2017	**2017**	**2016**
Assets			
Current assets	1 203	1 262	1 587
Property, plant and equipment	21 050	19 757	18 388
Non-current assets	794	753	660
Total assets before regulatory deferral balance	23 047	21 772	20 635
Regulatory deferral balance	608	566	516
	23 655	22 338	21 151
Liabilities and Equity			
Current liabilities	2 023	1 620	954
Long-term debt	16 887	16 102	15 833
Other long-term liabilities	1 554	1 526	1 602
Deferred revenue	724	653	579
Non-controlling interest	184	170	155
Retained earnings	2 810	2 899	2 756
Accumulated other comprehensive loss	(592)	(709)	(786)
Total liabilities and equity before regulatory deferral balance	23 590	22 261	21 093
Regulatory deferral balance	65	77	58
	23 655	22 338	21 151

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Operating Activities				
Earnings before depreciation, amortization and net finance expense (Adjusted EBITDA)	438	440	241	232
Adjustments for non-cash items included in adjusted EBITDA	(14)	5	(6)	(4)
Adjustments for non-cash working capital accounts	(133)	164	6	239
Net interest paid	(476)	(430)	(235)	(217)
	(185)	179	6	250
Investing Activities	(1 403)	(1 340)	(2 431)	(1 914)
Financing Activities	1 556	1 286	2 190	1 829
Net increase (decrease) in cash	(32)	125	(235)	165
Cash at beginning of period	646	955	849	915
Cash at end of period	614	1 080	614	1 080

Consolidated Statement of Comprehensive Income (Loss)

In Millions of Dollars (Unaudited)

	Six Months Ended September 30		Three Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Net Loss attributable to Manitoba Hydro	(89)	(72)	(20)	(24)
Other Comprehensive Income (Loss)				
Items that will be reclassified to income				
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	104	(19)	61	(14)
Items that have been reclassified to income				
Realized foreign exchange (gains) losses on debt in cash flow hedges	13	10	6	5
	117	(9)	67	(9)
Comprehensive Income (Loss) attributable to Manitoba Hydro	28	(81)	47	(33)

Segmented Information

In Millions of Dollars (Unaudited)

	Electric segment		Natural gas segment		All other segments		Eliminations		Total	
Six Months Ended September 30	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Revenue	920	879	89	96	30	30	(4)	(4)	1 035	1 001
Expenses	1 033	966	128	115	28	27	(5)	(6)	1 184	1 102
Net income (loss) before net movement in regulatory balances	(113)	(87)	(39)	(19)	2	3	1	2	(149)	(101)
Net movement in regulatory balances	40	28	13	(5)	-	-	-	-	53	23
Net Income (Loss)	(73)	(59)	(26)	(24)	2	3	1	2	(96)	(78)
Net income (loss) attribute to:										
Manitoba Hydro	(66)	(53)	(26)	(24)	2	3	1	2	(89)	(72)
Non-controlling interest	(7)	(6)	-	-	-	-	-	-	(7)	(6)
	(73)	(59)	(26)	(24)	2	3	1	2	(96)	(78)
Three Months Ended September 31										
Revenue	458	454	35	37	15	15	(3)	(2)	505	504
Expenses	489	481	56	56	14	13	(3)	(3)	556	547
Net income (loss) before net movement in regulatory balances	(31)	(27)	(21)	(19)	1	2	-	1	(51)	(43)
Net movement in regulatory balances	21	14	6	3	-	-	-	-	27	17
Net Income (Loss)	(10)	(13)	(15)	(16)	1	2	-	1	(24)	(26)
Net income (loss) attribute to:										
Manitoba Hydro	(6)	(11)	(15)	(16)	1	2	-	1	(20)	(24)
Non-controlling interest	(4)	(2)	-	-	-	-	-	-	(4)	(2)
	(10)	(13)	(15)	(16)	1	2	-	1	(24)	(26)
Total assets	23 094	20 620	718	673	90	76	(247)	(218)	23 655	21 151

Generation and Delivery Statistics

	Six Months Ended September 30		*Three Months Ended September 30*	
	2017	**2016**	**2017**	**2016**
Electricity in gigawatt-hours				
Hydraulic generation	17 926	17 291	9 150	8 815
Thermal generation	11	19	9	17
Scheduled energy imports	35	11	12	8
Wind purchases (Manitoba)	428	434	185	185
Total system supply	18 400	17 755	9 356	9 025
Gas in millions of cubic metres				
Gas sales	263	264	89	81
Gas transportation	267	345	124	165
	530	609	213	246

The Manitoba Hydro-Electric Board

Quarterly Report

for the six months ended
September 30, 2017

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Manitoba Hydro

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PUB MFR 21

Financial Information

A schedule detailing General Consumer Revenue for 2005 through the test years detailing rate increases granted. [Appendix 11.16, 2015/16 GRA]

Please see the Figure below for the requested information.

Figure 1. General Consumer Revenue

MANITOBA HYDRO
DOMESTIC REVENUE

(000's)	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Outlook	2017/18 Forecast	2018/19 Forecast
Residential - Base Rates	$ 373 725	$ 360 362	$ 381 543	$ 397 742	$ 405 896	$ 401 304	$ 411 995	$ 390 436	$ 437 224	$ 457 637	$ 446 049	$ 419 166	$ 423 102	$ 442 144	$ 444 123
General Service - Base Rates	534 941	555 836	570 090	581 123	583 448	563 954	571 525	584 748	604 273	603 547	608 124	600 779	610 220	616 602	609 374
Base Rates	908 665	916 198	951 633	978 866	989 345	965 258	983 520	975 185	1 041 497	1 061 184	1 054 173	1 019 946	1 033 322	1 058 747	1 053 497
2004/05 Approved Rate Increase (5.0% August 1, 2004)	30 289	45 810	47 582	48 943	49 467	48 263	49 176	48 759	52 075	53 059	52 709	50 997	51 269	52 536	52 265
2005/06 Approved Rate Increase (2.25% April 1, 2005)	-	21 645	22 482	23 126	23 373	22 804	23 236	23 039	24 605	25 070	24 905	24 096	24 224	24 823	24 695
2006/07 Approved Rate Increase (2.25% March 1, 2007)	-		1 916	23 646	23 899	23 317	23 758	23 557	25 159	25 635	25 465	24 638	24 769	25 382	25 251
2008/09 Approved Rate Increase (5.0% July 1, 2008)	-	-	-	-	40 728	52 982	53 984	53 527	57 167	58 247	57 863	55 984	56 282	57 673	57 376
2009/10 Approved Rate Increase (2.9% April 1, 2009)	-	-	-	-	-	32 266	32 877	32 598	34 815	35 473	35 238	34 094	34 276	35 123	34 942
2010/11 Approved Rate Increase (2.9% April 1, 2010)	-	-	-	-	-	-	33 830	33 543	35 824	36 501	36 260	35 083	35 270	36 141	35 955
2011/12 Approved Rate Increase (2.0% April 1, 2011)	-	-	-	-	-	-	-	23 804	25 423	25 903	25 732	24 897	25 029	25 648	25 516
2012/13 Approved Rate Increase (2.0% April 1, 2012)	-	-	-	-	-	-	-	-	25 931	26 421	26 247	25 395	25 530	26 161	26 026
2012/13 Approved Rate Increase (2.4% September 1, 2012)									18 515	32 340	32 126	31 083	31 248	32 021	31 856
2013/14 Approved Rate Increase (3.5% May 1, 2013)										44 293	47 975	46 417	46 664	47 818	47 571
2014/15 Approved Rate Increase (2.75% May 1, 2014)											36 071	37 747	37 948	38 886	38 686
2015/16 Approved Rate Increase (3.95% August 1, 2015)												39 589	56 006	57 390	57 095
2016/17 Interim Rate Increase (3.36% August 1, 2016)													35 192	50 747	50 485
Interim & Approved Rate Increases	30 289	67 455	71 980	95 715	137 468	179 633	216 861	238 827	299 514	362 943	400 591	430 022	483 708	510 347	507 718
2010/11 (1% rate rollback)	-	-	-	-	-	-	-	(22 894)	-	-	-	-	-	-	-
Deferred Revenue from 1% rate rollback	-	-	-	-	-	-	-	(22 894)	-	-	-	-	-	-	-
Additional Domestic Revenue (7.90% August 1, 2017)	-	-	-	-	-	-	-	-	-	-				87 638	122 688
Additional Domestic Revenue (7.90% April 1, 2018)															132 381
Additional Domestic Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	87 638	255 069
Bipole III Reserve Transfers	-	-	-	-	-	-	-	-	-	(18 826)	(30 249)	(51 203)	(95 916)	(119 431)	(38 606)
Bipole III Reserve Amortization															47 231
Bipole III Reserve Account	-	-	-	-	-	-	-	-	-	(18 826)	(30 249)	(51 203)	(95 916)	(119 431)	8 625
Total Domestic Revenue	$ 938 954	$ 983 653	$ 1 023 613	$ 1 074 581	$ 1 126 812	$ 1 144 891	$ 1 200 381	$ 1 191 118	$ 1 341 011	$ 1 405 301	$ 1 424 515	$ 1 398 765	$ 1 421 114	$ 1 537 300	$ 1 824 909
Rate increase requested	3.00%	2.50%	2.25%	n/a	2.90%	3.90%	2.90%	2.90%	3.50%	3.50%	3.95%	3.95%	3.95%	7.90%	7.90%
Rate increase granted	5.00%	2.25%	2.25%	n/a	5.00%	2.90%	2.90%	2.00%	2.0%/2.4%	3.50%	2.75%	3.95%	3.36%	n/a	n/a

EXTRAPROVINCIAL REVENUE

(000's)	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Forecast	2017/18 Forecast	2018/19 Forecast
Extraprovincial Revenue	$ 553 727	$ 826 766	$ 592 245	$ 624 971	$ 622 646	$ 426 641	$ 398 306	$ 363 044	$ 352 633	$ 439 182	$ 400 294	$ 415 028	$ 467 568	$ 454 201	$ 431 769
Water Rentals and Assessments	(135 456)	(124 841)	(226 212)	(134 887)	(176 383)	(103 973)	(106 169)	(145 632)	(133 292)	(125 517)	(124 887)	(126 086)	(131 209)	(124 130)	(112 463)
Fuel and Power Purchased	(111 521)	(131 020)	(112 497)	(123 767)	(123 000)	(121 033)	(120 163)	(119 301)	(117 864)	(177 113)	(145 769)	(117 178)	(129 926)	(135 428)	(165 702)
Net Extraprovincial Revenue	$ 306 750	$ 570 905	$ 253 536	$ 366 316	$ 323 264	$ 201 635	$ 171 974	$ 98 111	$ 101 477	$ 136 552	$ 129 638	$ 171 765	$ 206 433	$ 194 644	$ 153 604

Year	% Rate Increase Requested	% Approved Final/Interim[1]	MB CPI	Revenues from Rate increases in Fiscal Year ($millions)	Annualized Revenues from Rate Increases ($ millions)	Cumulative % Increase (Approved)	Cumulative MB CPI	Cumulative Additional Annualized Rev. from Approved Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
1999/00	n/a - 0%	-	2.2%	$0.0	$0.0	0.00%	2.20%	$0.0	66%	83:17
2000/01	n/a - 0%	-	2.5%	$0.0	$0.0	0.00%	4.76%	$0.0	62%	80:20
2001/02	n/a - 0%*	-1.92% Nov 1/01	2.1%	($6.0)	($14.4)	-1.92%	6.95%	($14.4)	57%	77:23
2002/03	n/a - 0%	-	2.3%	$0.0	$0.0	-1.92%	9.41%	($14.4)	65%	80:20
2003/04	n/a - 0%	-0.72% Apr 1/03	0.9%	($6.5)	($6.5)	-2.63%	10.40%	($20.9)	72%	87:13
2004/05	3% Apr 1/04	5% Aug 1/04	2.7%	$32.3	$45.9	2.24%	13.38%	$25.0	63%	85:15
2005/06	2.5% Apr 1/05	2.25% Apr 1/05 **	2.4%	$21.8	$21.8	4.54%	16.10%	$46.8	55%	81:19
2006/07	2.25% Feb 1/07	2.25% Mar 1/07 **	2.0%	$1.9	$23.1	6.90%	18.42%	$69.9	66%	80:20
2007/08	0% Apr 1/07	-	1.9%	$0.0	$0.0	6.90%	20.67%	$69.9	66%	73:27
2008/09	2.9% Apr 1/08	5.0% Jul 1/08	2.2%	$39.3	$52.4	12.24%	23.33%	$122.3	68%	77:23
2009/10	3.9% Apr 1/09	2.84% Apr 1/09	0.6%	$32.8	$32.8	15.43%	24.07%	$155.1	75%	73:27
2010/11	2.9% Apr 1/10	2.8% Apr 1/10 **	1.0%	$32.9	$32.9	18.66%	25.31%	$188.0	77%	73:27
2011/12	2.9% Apr 1/11	2.0% Apr 1/11 **	2.8%	$24.4	$24.4	21.03%	28.82%	$212.4	78%	74:26
2012/13	3.5% Apr 1/12	2.0% Apr 1/12 **	1.6%	$25.8	$25.8	23.45%	30.88%	$238.2	80%	75:25
2012/13	2.5% Sep 1/12	2.4% Sep 1/12 **	1.6%	$19.4	$31.0	26.42%	30.88%	$269.2	80%	75:25
2013/14	3.5% Apr 1/13	3.5% May 1/13	2.4%	$43.4	$47.6	30.84%	34.02%	$316.8	78%	76:24
2014/15	3.95% Apr 1/14	2.75% May 1/14 **	1.5%	$35.6	$38.7	34.44%	36.43%	$355.5	79%	82:18
2015/16	3.95% Apr 1/15	3.95% Aug 1/15	1.3%	$40.1	$57.4	39.75%	37.80%	$412.9	77%	83:17
2016/17	3.95% Apr 1/16	3.36% Aug 1/16 **	1.4%	$36.6	$52.3	44.44%	39.73%	$465.2	76%	84:16
2017/18	7.9% Aug 1/17	3.36% Aug 1/17**	2.0% ****	$37.3	$52.4	49.30%	42.52%	$517.6	80%****	85:15****
2018/19***	7.9% Apr 1/18 prop	n/a	2.1% ****	$127.2	$127.2	61.09%	45.52%	$644.8	78%****	85:15****

* Implementation of Uniform Rate Legislation.
** Interim-approved rate increases as per Note below.
*** Calculations assume that the proposed rate increase for fiscal year 2018/19 is approved.
**** Forecast

[1] Note: The following rate increases were approved on an interim basis: April 1, 2005 Order 101/04; March 1, 2007 Order 20/07; April 1, 2010 Order 18/10; April 1, 2011 Order 40/11; April 1, 2012 Order 32/12; September 1, 2012 Orders 116/12 and 117/12; May 1, 2014 Order 49/14; August 1, 2016 Order 59/16; and August 1, 2017 Order 80/17. All interim increases have since been approved as final with the exception of Order 59/16 and 80/17.

REFERENCE:

Tab 2, PUB MFR12

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide the present value of the proposed annualized revenue increase requested for each of 2017/18 and 2018/19 over the next twenty years of the planning horizon on the basis of i) excluding and ii) including the planned 7.9% increases forecast for each year. Please utilize MH's weighted average cost of capital.

RATIONALE FOR QUESTION:

RESPONSE:

The present value of additional annual revenues over 20 years assuming no rate increase for 2017/18 or 2018/19 is $8.0 billion (at 6.25% nominal WACC discount rate).

Including the interim 3.36% rate increase in 2017/18 and the proposed 7.90% for 2018/19, the present value of additional annual revenues over 20 years is $10.9 billion.

Stated another way, the additional domestic revenues associated with the 2017/18 and 2018/19 rate increases over 20 years are worth $2.9 billion in 2017 dollars.

The attached schedule provides the calculation.

In Millions of Dollars

				PUB/MH I-3b(i)				MH16 Update with Interim - PUB/MH I-3b(ii)				PV 2017/18 & 2018/19 Rate Increases	
	Nominal WACC	Discount Factor	MH16 Update Total Domestic Revenue	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue	Additional GCR	Discounted Additional GCR
2018	6.25%	1.000	1,578	0.00%	0.00%	-	-	3.36%	2.38%	37	37	37	37
2019	6.25%	1.063	1,565	0.00%	0.00%	-	-	7.90%	11.53%	179	169	179	169
2020	6.25%	1.129	1,551	7.90%	7.90%	122	108	7.90%	20.34%	315	279	193	171
2021	6.25%	1.199	1,537	7.90%	16.42%	252	210	7.90%	29.84%	458	382	206	172
2022	6.25%	1.274	1,544	7.90%	25.62%	395	310	7.90%	40.10%	619	486	223	175
2023	6.25%	1.354	1,542	7.90%	35.55%	548	405	7.90%	51.17%	789	582	241	178
2024	6.25%	1.439	1,542	7.90%	46.25%	713	496	7.90%	63.11%	973	676	260	181
2025	6.25%	1.529	1,553	4.54%	52.89%	821	537	4.54%	70.52%	1,094	716	273	179
2026	6.25%	1.624	1,567	2.00%	55.95%	876	539	2.00%	73.93%	1,158	713	281	173
2027	6.25%	1.726	1,583	2.00%	59.07%	934	541	2.00%	77.40%	1,224	710	290	168
2028	6.25%	1.834	1,599	2.00%	62.25%	995	543	2.00%	80.95%	1,294	706	299	163
2029	6.25%	1.948	1,614	2.00%	65.50%	1,057	542	2.00%	84.57%	1,364	700	308	158
2030	6.25%	2.070	1,630	2.00%	68.81%	1,121	542	2.00%	88.26%	1,438	695	317	153
2031	6.25%	2.199	1,647	2.00%	72.18%	1,188	540	2.00%	92.03%	1,515	689	327	149
2032	6.25%	2.337	1,673	2.00%	75.63%	1,265	541	2.00%	95.87%	1,603	686	339	145
2033	6.25%	2.483	1,701	2.00%	79.14%	1,345	542	2.00%	99.79%	1,696	683	351	141
2034	6.25%	2.638	1,729	2.00%	82.72%	1,429	542	2.00%	103.78%	1,793	680	364	138
2035	6.25%	2.803	1,757	2.00%	86.38%	1,517	541	2.00%	107.86%	1,894	676	377	135
2036	6.25%	2.978	1,786	2.00%	90.10%	1,608	540	2.00%	112.01%	1,999	671	391	131
NPV							**8,020**				**10,936**		**2,915**

In Millions of Dollars

	PUB/MH I-3(ii) Including Planned 7.9% Increases in Test Years				PUB/MH I-3(ii) With Compounding due to Projected Future Rate Increases				
	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue	Annual Rate Increases per PUB/MH I-3(i)	Effective Cumulative Rate Increases per PUB/MH I-3(i)	Additional Domestic Revenue due to Compounding of Future Rate Increases	Discounted Additional Domestic Revenue due to Compounding of Future Rate Increases	Total Discounted Additional Domestic Revenue
2018	3.36%	2.38%	37	37	0.00%	0.00%	-	-	37
2019	7.90%	11.53%	179	169	0.00%	0.00%	-	-	169
2020	0.00%	11.53%	179	158	7.90%	7.90%	14	13	171
2021	0.00%	11.53%	177	148	7.90%	16.42%	29	24	172
2022	0.00%	11.53%	178	140	7.90%	25.62%	46	36	175
2023	0.00%	11.53%	178	131	7.90%	35.55%	63	47	178
2024	0.00%	11.53%	178	123	7.90%	46.25%	82	57	181
2025	0.00%	11.53%	179	117	4.54%	52.89%	95	62	179
2026	0.00%	11.53%	180	111	2.00%	55.95%	101	62	173
2027	0.00%	11.53%	182	106	2.00%	59.07%	108	62	168
2028	0.00%	11.53%	184	100	2.00%	62.25%	115	63	163
2029	0.00%	11.53%	186	95	2.00%	65.50%	122	63	158
2030	0.00%	11.53%	188	91	2.00%	68.81%	129	62	153
2031	0.00%	11.53%	190	86	2.00%	72.18%	137	62	149
2032	0.00%	11.53%	193	82	2.00%	75.63%	146	62	145
2033	0.00%	11.53%	196	79	2.00%	79.14%	155	62	141
2034	0.00%	11.53%	199	75	2.00%	82.72%	165	62	138
2035	0.00%	11.53%	202	72	2.00%	86.38%	175	62	135
2036	0.00%	11.53%	206	69	2.00%	90.10%	185	62	131
NPV				**1 991**				**924**	**2 915**

Section:	Tab 2	**Page No.:**	PUB/MH I-3/ PUB/MH I-4
Topic:	Overview and Reasons for Application		
Subtopic:	Rate Increase		
Issue:	Present Values of GRA Rate Increases		

PREAMBLE TO IR (IF ANY):

In IFF14 restated in PUB/MH I-4 the incremental additional revenue is $35 million in 2015 and $61 million in 2016 for a total of $96 million.

QUESTION:

a) Please provide the NPV analysis based on the updated figure of $61 million for 2016.

b) Please provide the analysis based on $96 million using 2016 as the starting point for the analysis.

RATIONALE FOR QUESTION:

To understand the full financial implications of the proposed 2014/15 and 2015/16 rate increases over the 20 year forecast.

RESPONSE:

a) The incremental additional revenue attributable to the proposed 3.95% rate increase effective April 1, 2015 is $57 million. The incremental additional revenue of $35 million for 2014/15 is the result of the 2.75% rate increase, effective May 1, 2014, for 11 months of the year. The full year impact of the 2.75% rate increase in 2015/16 is $39 million for total additional revenue in 2015/16 of $96 million as shown in the table below.

	2015	2016
General Consumers		
at approved rates	1 401	1 415
additional - 2.75% May 1, 2014 to March 31, 2015	35	-
additional - 2.75% April 1, 2015 to March 31, 2016	-	39
additional - 3.95% April 1, 2015 to March 31, 2016	-	57
Total additional revenue	35	96

The present value of the proposed $57 million additional General Consumers Revenue for 2015/16 is $848 million as shown in PUB/MH-I-3.

b) The attached schedule calculates the present value of the proposed $96 million additional General Consumers Revenue for 2015/16 over the 20 year forecast assuming no further rate increases over the 20 year period to 2033/34. This results in a present value of $1,056 million.

The total discounted additional General Consumers Revenue assuming compounding of future rates increases is $1,423 million.

In Millions of Dollars

				PUB/MH I-4				PUB/MH II-3(b)				PUB/MH II-4 less PUB/MH II-3(b)	
	Nominal WACC	**Discount Factor**	**PUB/MH I-4 General Consumers Revenue**	**Annual Rate Increases**	**Cumulative Rate Increases**	**Additional GCR**	**Discounted Additional GCR**	**Annual Rate Increases**	**Cumulative Rate Increases**	**Additional GCR**	**Discounted Additional GCR**	**Additional GCR**	**Discounted Additional GCR**
2015	6.95%	1.000	1 401	2.75%	2.75%	35	35	2.75%	2.75%	35	35	-	-
2016	6.95%	1.070	1 415	3.95%	6.81%	96	90	3.95%	0.00%	-	-	96	90
2017	6.95%	1.144	1 421	3.95%	11.03%	157	137	3.95%	3.95%	56	49	101	88
2018	6.95%	1.223	1 443	3.95%	15.41%	222	182	3.95%	8.06%	116	95	106	87
2019	6.95%	1.308	1 450	3.95%	19.97%	290	221	3.95%	12.32%	179	137	111	85
2020	6.95%	1.399	1 461	3.95%	24.71%	361	258	3.95%	16.76%	245	175	116	83
2021	6.95%	1.497	1 466	3.95%	29.64%	434	290	3.95%	21.37%	313	209	121	81
2022	6.95%	1.601	1 473	3.95%	34.76%	512	320	3.95%	26.17%	385	241	127	79
2023	6.95%	1.712	1 485	3.95%	40.08%	595	348	3.95%	31.15%	462	270	133	77
2024	6.95%	1.831	1 496	3.95%	45.61%	683	373	3.95%	36.33%	544	297	139	76
2025	6.95%	1.958	1 510	3.95%	51.37%	776	396	3.95%	41.72%	630	322	146	74
2026	6.95%	2.094	1 524	3.95%	57.34%	874	417	3.95%	47.31%	721	344	153	73
2027	6.95%	2.240	1 537	3.95%	63.56%	977	436	3.95%	53.13%	817	365	160	72
2028	6.95%	2.395	1 551	3.95%	70.02%	1 086	453	3.95%	59.18%	918	383	168	70
2029	6.95%	2.562	1 564	3.95%	76.74%	1 200	469	3.95%	65.47%	1 024	400	176	69
2030	6.95%	2.740	1 580	3.95%	83.72%	1 323	483	3.95%	72.01%	1 138	415	185	68
2031	6.95%	2.930	1 597	3.95%	90.97%	1 453	496	3.95%	78.80%	1 259	430	194	66
2032	6.95%	3.134	1 614	2.00%	94.79%	1 530	488	2.00%	82.38%	1 330	424	200	64
2033	6.95%	3.352	1 632	2.00%	98.69%	1 611	481	2.00%	86.02%	1 404	419	207	62
2034	6.95%	3.585	1 650	2.00%	102.66%	1 694	473	2.00%	89.74%	1 481	413	213	59
NPV							**6 846**				**5 423**		**1 423**

In Millions of Dollars

	PUB/MH II-3(b) Assuming No Projected Future Rate Increases				PUB/MH II-3(b) With Compounding due to Projected Future Rate Increases				
	Annual Rate Increases	Cumulative Rate Increases	Additional GCR	Discounted Additional GCR	Annual Rate Increases per MH14	Cumulative Rate Increases per MH14	Additional GCR due to Compounding of Future Rate Increases	Discounted Additional GCR due to Compounding of Future Rate Increases	Total Discounted Additional GCR
2015	0.00%	0.00%	-	-	0.00%	0.00%	-		
2016	6.81%	6.81%	96	90	0.00%	0.00%	-	-	90
2017	0.00%	6.81%	97	85	3.95%	3.95%	4	3	88
2018	0.00%	6.81%	98	80	3.95%	8.06%	8	6	87
2019	0.00%	6.81%	99	75	3.95%	12.32%	12	9	85
2020	0.00%	6.81%	99	71	3.95%	16.76%	17	12	83
2021	0.00%	6.81%	100	67	3.95%	21.37%	21	14	81
2022	0.00%	6.81%	100	63	3.95%	26.17%	26	16	79
2023	0.00%	6.81%	101	59	3.95%	31.15%	31	18	77
2024	0.00%	6.81%	102	56	3.95%	36.33%	37	20	76
2025	0.00%	6.81%	103	53	3.95%	41.72%	43	22	74
2026	0.00%	6.81%	104	50	3.95%	47.31%	49	23	73
2027	0.00%	6.81%	105	47	3.95%	53.13%	56	25	72
2028	0.00%	6.81%	106	44	3.95%	59.18%	62	26	70
2029	0.00%	6.81%	106	42	3.95%	65.47%	70	27	69
2030	0.00%	6.81%	108	39	3.95%	72.01%	77	28	68
2031	0.00%	6.81%	109	37	3.95%	78.80%	86	29	66
2032	0.00%	6.81%	110	35	2.00%	82.38%	91	29	64
2033	0.00%	6.81%	111	33	2.00%	86.02%	96	29	62
2034	0.00%	6.81%	112	31	2.00%	89.74%	101	28	59
NPV				**1 056**				**367**	**1 423**

REFERENCE:

MIPUG/MH I-2k

PREAMBLE TO IR (IF ANY):

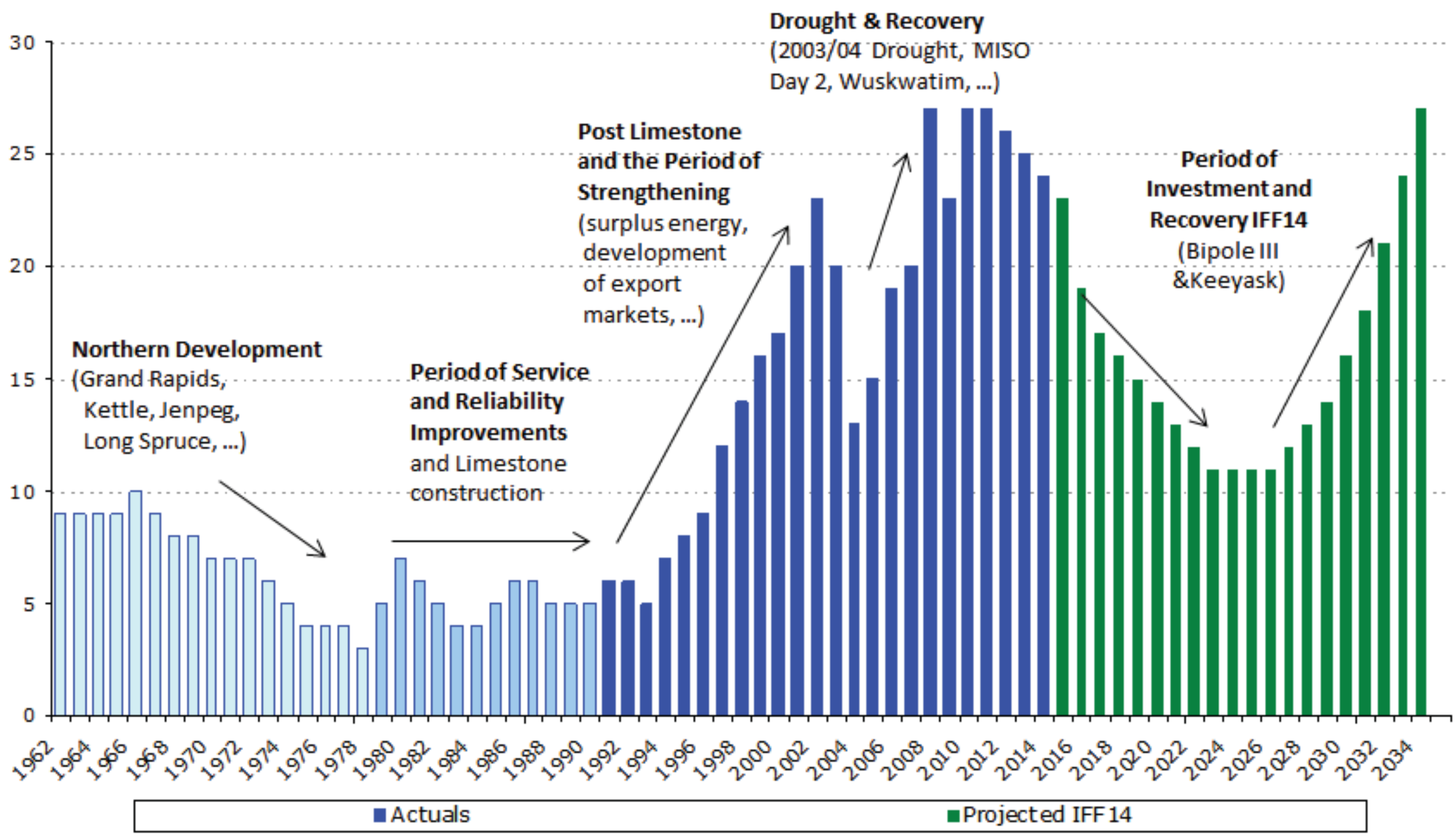
QUESTION:

a) Please provide Figure 3-1 from Appendix 4.1 (the KPMG report) for the period 1962 to 2034 (i.e. same period as provided in MIPUG/MH I-2k).
b) For each of the figures on pages 7 of 14 to 9 of 14, as well as the original Figure 3-1 from Appendix 4.1, please provide the real average prices of domestic energy sold, by year.

RATIONALE FOR QUESTION:

RESPONSE:

a) The graph below reflects Figure 3-1 from Appendix 4.1 and has been updated to include Manitoba Hydro's equity ratio from 1962 to 2034 a)


Drought & Recovery
(2003/04 Drought, MISO
Day 2, Wuskwatim, ...)
Post Limestone
and the Period of
Strengthening
(surplus energy,
development
of export
markets, ...)
Period of
Investment and
Recovery IFF14
(Bipole III
&Keeyask)
Northern Development
(Grand Rapids,
Kettle, Jenpeg,
Long Spruce, ...)
Period of Service
and Reliability
Improvements
and Limestone
construction
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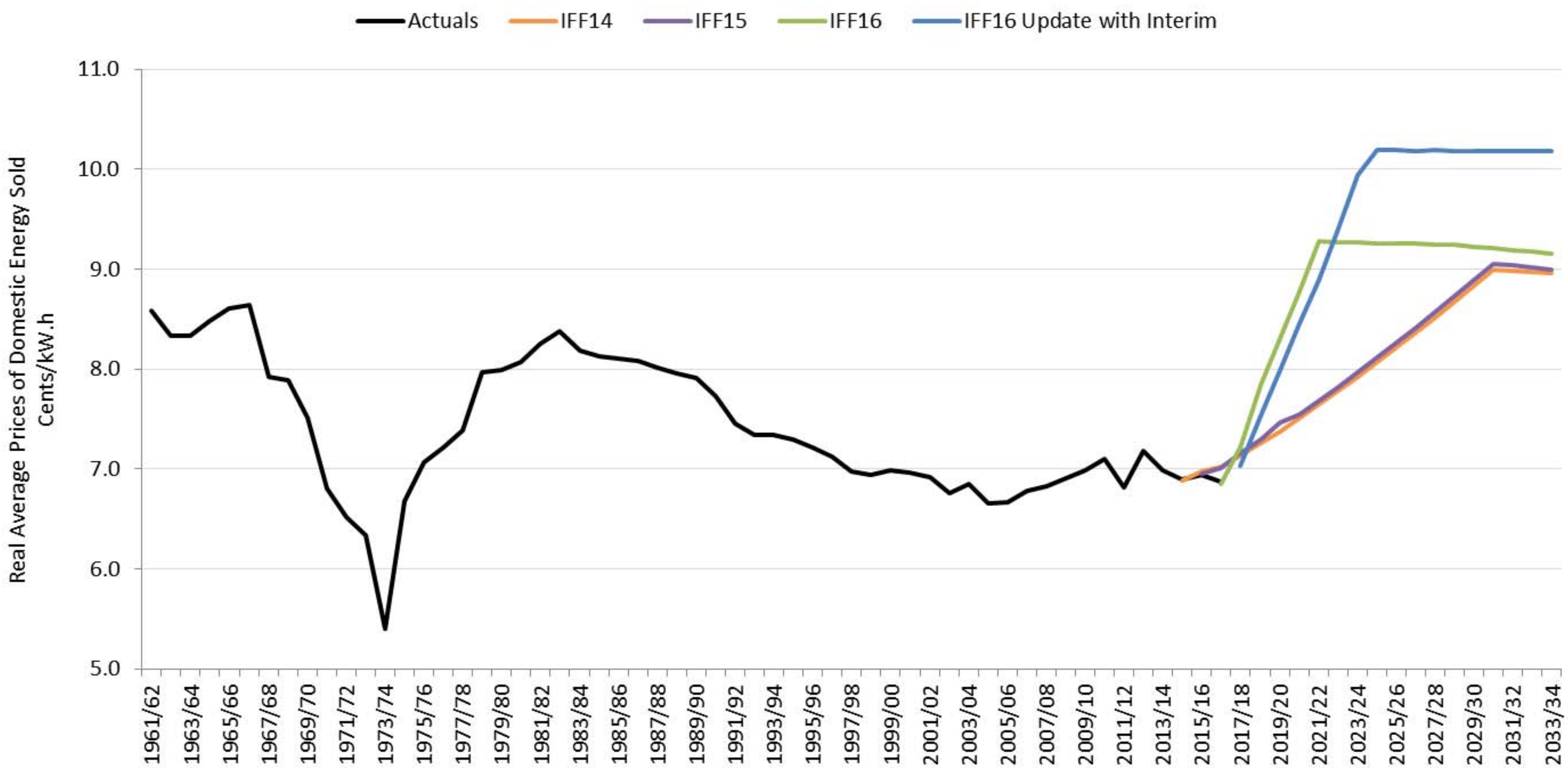
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Actuals
Projected IFF 14

b) The following table and chart provide the real average prices of domestic energy sold by year.

It can be seen from the chart that except for the period from 1975 to 1983, the latter period of the Nelson River generation development, real electricity prices have been generally declining until the early 2000's reflecting the period where Manitoba Hydro did not implement any or significant rate increases. Real electricity prices from that period until today have been relatively flat reflecting the beneficial influence of the period of lucrative export sales. The combination of the new major projects coming on-line and the current and projected lowest export prices in Manitoba Hydro's history have resulted in the first real electricity price increases since the early 80's.

Real Average Prices of Domestic Energy Sold Cents/kW.h						Adj	Nominal Average Prices of Domestic Energy Sold Cents/kW.h					
Fiscal Year	Actuals	IFF14	IFF15	IFF16	IFF16 Update with Interim	CPI	Fiscal Year	Actuals	IFF14	IFF15	IFF16	IFF16 Update with Interim
1961/62	8.6					18.7	1961/62	1.1				
1962/63	8.3					18.4	1962/63	1.1				
1963/64	8.3					18.4	1963/64	1.1				
1964/65	8.5					18.4	1964/65	1.1				
1965/66	8.6					18.1	1965/66	1.1				
1966/67	8.6					18.1	1966/67	1.1				
1967/68	7.9					19.9	1967/68	1.1				
1968/69	7.9					20.8	1968/69	1.1				
1969/70	7.5					21.2	1969/70	1.1				
1970/71	6.8					23.1	1970/71	1.1				
1971/72	6.5					23.7	1971/72	1.1				
1972/73	6.3					24.7	1972/73	1.1				
1973/74	5.4					26.3	1973/74	1.0				
1974/75	6.7					27.9	1974/75	1.3				
1975/76	7.1					31.2	1975/76	1.5				
1976/77	7.2					36.6	1976/77	1.8				
1977/78	7.4					42.2	1977/78	2.2				
1978/79	8.0					45.4	1978/79	2.5				
1979/80	8.0					49.3	1979/80	2.7				
1980/81	8.1					49.4	1980/81	2.8				
1981/82	8.2					49.5	1981/82	2.8				
1982/83	8.4					49.5	1982/83	2.9				
1983/84	8.2					53.9	1983/84	3.1				
1984/85	8.1					58.9	1984/85	3.3				
1985/86	8.1					61.8	1985/86	3.5				
1986/87	8.1					63.2	1986/87	3.5				
1987/88	8.0					70.3	1987/88	3.9				
1988/89	8.0					73.6	1988/89	4.1				
1989/90	7.9					77.6	1989/90	4.3				
1990/91	7.7					82.8	1990/91	4.4				
1991/92	7.5					89.1	1991/92	4.6				
1992/93	7.3					92.1	1992/93	4.7				
1993/94	7.3					92.1	1993/94	4.7				
1994/95	7.3					93.9	1994/95	4.8				
1995/96	7.2					95.5	1995/96	4.8				
1996/97	7.1					98.1	1996/97	4.9				
1997/98	7.0					100.3	1997/98	4.9				
1998/99	6.9					100.3	1998/99	4.8				
1999/00	7.0					100.3	1999/00	4.9				
2000/01	7.0					100.3	2000/01	4.9				
2001/02	6.9					100.2	2001/02	4.8				
2002/03	6.8					100.0	2002/03	4.7				
2003/04	6.9					100.0	2003/04	4.8				
2004/05	6.7					102.9	2004/05	4.8				
2005/06	6.7					106.4	2005/06	4.9				
2006/07	6.8					105.9	2006/07	5.0				
2007/08	6.8					107.6	2007/08	5.1				
2008/09	6.9					110.6	2008/09	5.3				
2009/10	7.0					115.0	2009/10	5.6				
2010/11	7.1					117.1	2010/11	5.8				
2011/12	6.8					121.0	2011/12	5.7				
2012/13	7.2					125.1	2012/13	6.2				
2013/14	7.0					131.2	2013/14	6.4				
2014/15	6.9	6.9				135.1	2014/15	6.5	6.5			
2015/16	6.9	7.0	7.0			138.9	2015/16	6.7	6.7	6.7		
2016/17	6.9	7.0	7.0	6.9		143.9	2016/17	6.9	7.0	7.0	6.9	
2017/18		7.1	7.2	7.2	7.0	146.8	2017/18		7.3	7.3	7.4	7.2
2018/19		7.3	7.3	7.8	7.5	149.8	2018/19		7.6	7.6	8.2	7.8
2019/20		7.4	7.5	8.3	8.0	152.9	2019/20		7.8	7.9	8.8	8.5
2020/21		7.5	7.6	8.8	8.5	156.1	2020/21		8.1	8.2	9.5	9.2
2021/22		7.6	7.7	9.3	8.9	159.3	2021/22		8.5	8.5	10.3	9.8
2022/23		7.8	7.8	9.3	9.4	162.5	2022/23		8.8	8.8	10.5	10.6
2023/24		7.9	8.0	9.3	9.9	165.8	2023/24		9.1	9.2	10.7	11.5
2024/25		8.1	8.1	9.3	10.2	169.1	2024/25		9.5	9.5	10.9	12.0
2025/26		8.2	8.3	9.3	10.2	172.5	2025/26		9.9	9.9	11.1	12.2
2026/27		8.4	8.4	9.3	10.2	176.0	2026/27		10.2	10.3	11.3	12.5
2027/28		8.5	8.6	9.2	10.2	179.5	2027/28		10.6	10.7	11.5	12.7
2028/29		8.7	8.7	9.2	10.2	183.1	2028/29		11.0	11.1	11.8	13.0
2029/30		8.8	8.9	9.2	10.2	186.8	2029/30		11.5	11.5	12.0	13.2
2030/31		9.0	9.1	9.2	10.2	190.6	2030/31		11.9	12.0	12.2	13.5
2031/32		9.0	9.0	9.2	10.2	194.4	2031/32		12.1	12.2	12.4	13.8
2032/33		9.0	9.0	9.2	10.2	198.3	2032/33		12.4	12.4	12.6	14.0
2033/34		9.0	9.0	9.2	10.2	202.3	2033/34		12.6	12.7	12.9	14.3


Actuals
IFF14
IFF15
IFF16
IFF16 Update with Interim
Real Average Prices of Domestic Energy Sold
Cents/kW.h
11.0
10.0
9.0
8.0
7.0
6.0
5.0
1961/62
1963/64
1965/66
1967/68
1969/70
1971/72
1973/74
1975/76
1977/78
1979/80
1981/82
1983/84
1985/86
1987/88
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1993/94
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2011/12
2013/14
2015/16
2017/18
2019/20
2021/22
2023/24
2025/26
2027/28
2029/30
2031/32
2033/34

4.0 Manitoba Hydro's Application for an Interim Rate

Previous Rate Increases

In June of 2012, Manitoba Hydro filed a General Rate Application seeking a 3.5% increase in consumer rates effective April 1, 2013. In Board Order 43/13, the Board approved an overall increase of 3.5% to all customer classes, but ordered the revenues from 1.5% of the overall increase to be placed in the Bipole III Deferral Account. In Order 49/14, the Board, on an interim basis, further approved a 2.75% overall average rate increase, but the revenues from 0.75% of the overall increase were to be placed into the Bipole III Deferral Account.

Following Manitoba Hydro's filing of a General Rate Application in 2015 for revised electricity rates, the Board in Order 73/15 finalized the 2014/15 interim rate increase and awarded a further 3.95% increase to billed rates for the 2015/16 fiscal year, effective August 1, 2015. Of this 3.95% increase, the revenues from a 2.15% increase were to be placed in the Bipole III Deferral Account.

In November 2015, Manitoba Hydro filed an interim rate application seeking an interim rate increase of 3.95% for all customer classes, effective April 1, 2016. In Order 59/16, the Board granted a 3.36% increase, with all revenues from the increase directed to the Bipole III Deferral Account. Order 59/16 also directed Manitoba Hydro to file a General Rate Application by no later than December 1, 2016 to allow for the adjustment of consumer rates for August, 2017.

As noted above, and despite the directive in Order 59/16, Manitoba Hydro filed in May 2017 the General Rate Application currently before the Board, including the request for an interim rate increase.

Manitoba Hydro
Rate Increases 2003/04 to 2018/19

Year	% Rate Increase Requested	% Approved Final/Interim		Rate increase Directed to Bipole III Account	Cumulative Rate Increase Bipole III	Bipole III Fund Contribution	MB CPI	Annual Increase in Revenue ($millions)	Cumulative % Increase	Cumulative MB CPI	Additional Revenue from Rate Increases	Revenue from Domestic (Actual)	Consolidated Debt to Equity Ratio
2003/04	**0% Apr 1/03**	**-0.72% Apr 1/03**	**-0.07%**				**0.90%**	-$ 7	**-0.07%**	0.90%	**-$ 6.5**	**72%**	87:13
2004/05	3% Apr 1/04	5% Aug 1/04	5.00%				2.7%	32	4.9%	3.6%	26	63%	85:15
2005/06	2.5% Apr 1/05	2.25% Apr 1/05	2.25%				2.4%	22	7.3%	6.1%	47	54%	81:19
2006/07	2.25% Feb 1/07	2.25% Mar 1/07	2.25%				2.0%	23	9.7%	8.2%	70	63%	80:20
2007/08	0% Apr 1/07	-					1.9%	-	9.7%	10.3%	70	63%	73:27
2008/09	2.9% Apr 1/08	5.0% Jul 1/08	5.00%				2.2%	52	15.2%	12.7%	123	64%	77:23
2009/10	3.9% Apr 1/09	2.84% Apr 1/09	2.84%				0.6%	33	18.5%	13.4%	156	73%	73:27
2010/11	2.9% Apr 1/10	2.8% Apr 1/10	2.80%				1.0%	33	21.8%	14.5%	189	75%	73:27
2011/12	2.9% Apr 1/11	2.0% Apr 1/11	2.00%				2.8%	24	24.2%	17.7%	213	77%	74:26
2012/13	3.5% Apr 1/12	2.0% Apr 1/12	2.00%				1.6%	26	26.7%	19.6%	239	79%	75:25
2012/13	2.5% Sep 1/12	2.4% Sep 1/12	2.40%				1.6%	31	29.7%	21.5%	270	79%	75:25
2013/14	3.5% Apr 1/13	3.5% May 1/13 B.O. 43/13	3.50%	1.50%	1.50%	18.8	2.4%	48	34.3%	24.4%	317	hea	76:24
2014/15	3.95% Apr 1/14	2.75% May 1/14 B.O. 49/14	2.75%	0.75%	2.26%	30.3	1.80%	39	38.0%	26.7%	356	78%	76:24
2015/16*	3.95% Apr 1/15	3.95% , Aug 1/16 B.O. 73/15	3.95%	2.15%	4.5%	51.2	1.90%	57	43.4%	29.1%	413	78%	82:18
2016/17**	**3.95% Apr 1/16**	3.36% Aug 1/16 B.O. 59/16	**3.95%**	3.36%	8.0%	96.0	2.0%	**$ 51**	49.1%	31.7%	**$ 464**	**78%**	**83:17**
2017/18	**7.9% August 1/17**	**3.36% Aug 1/17 B.O. 80/17**	**3.36%**	3.36%	11.6%	151.0	**2%**	**52**	54.1%	34.3%	**$ 516**		**85:15**
2018/19	**7.9% Apr 1/18**	**TBD**	**7.90%**	n/a	n/a	51.7	**2%**	**127**	66.3%	37.0%	**$ 643**		**85:15**
				n/a	n/a	399.0							

REFERENCE:

Tab 6 Page 3 of 55

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide a continuity schedule of annual contributions and proposed drawdowns of the Bipole III reserve account since inception.

RATIONALE FOR QUESTION:

RESPONSE:

The continuity schedule below (based on the MH16 Update with Interim) displays the annual contributions and proposed drawdowns of the Bipole III reserve account by fiscal year.

Bipole III Reserve Account Reconciliation
(In thousands of dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening balance	-	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605
Contributions	18 825	30 249	51 204	96 018	151 017	51 739	-	-	-	-	-
Drawdowns	-	-	-	-	-	(53 207)	(79 810)	(79 810)	(79 810)	(79 810)	(26 605)
Ending balance	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605	-

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REFERENCE:

Tab 3, pg. 18

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the accounting issues paper related to the treatment of Conawapa under IAS 36 Impairment including the rationale surrounding the following assumptions:

a) Future economic benefits to support the carrying amount of the $380 million CWIP balance until April 1, 2019 (anticipated write-off date);
b) Eligibility of the recovery of the balance through the regulatory deferral account and the rationale for the 30-year write-off period

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) and b):

An issues paper relating to the accounting treatment of Conawapa under the IAS 36 Impairment standard was not prepared as it was Manitoba Hydro's intent, should a decision be made to ultimately suspend Conawapa to seek PUB endorsement of the inclusion of costs incurred with respect to the Conawapa Generating Station project into Manitoba Hydro's regulatory deferral balances with subsequent amortization. As such, Manitoba Hydro assumed there would be no impairment of the Construction Work In Progress balance.

It was decided to maintain the costs in Construction Work In Progress while the federal government was determining its strategy for federal carbon reduction initiatives. Overall, the assumption was that there was enough uncertainty with respect to the timing of such initiatives to warrant deferring the Conawapa project costs in Construction Work In Progress through to the end of fiscal 2018/19. MH16 assumes

Conawapa costs are recognized as a regulatory deferral account, with amortization commencing effective April 1, 2019.

The 30 year amortization period was assumed in order to minimize the potential further impact on rates.

$380 million be deferred as a regulatory asset and amortized over 30 years so as to minimize the impact on customer rates.

c) Please see the attached schedule detailing the actual capital costs incurred on Conawapa Generation and Licensing by year.

Manitoba Hydro 2016/2017 General Rate Application
PUB/MH-12c Cumulative Detail of the Conawapa Expenditures

CONAWAPA GS								**Fiscal Year**							
In thousands	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Total**
Conawapa - Generation															
Internal MH Staff Costs	$ 49	$ 2 503	$ 4 790	$ 6 762	$ 6 338	$ 5 792	6 292	5 141	5 526	6 880	10 562	3 884	668	576	65 764
External Consultants hired by MH	148	4 096	8 167	12 585	11 748	12 591	6 674	5 238	2 869	4 551	7 176	6 227	1 496	485	84 049
MH Funded Expenses for Costs Incurred by Third Parties	-	26	415	3 107	1 540	670	1 313	628	59	352	2 263	3 260	93	1	13 726
Materials & Other	-	1 563	13 992	5 239	4 707	2 294	2 305	4 116	3 299	309	302	276	98	62	38 561
Joint Generation Development Agreements, Process and Study Costs	-	291	734	1 510	3 958	3 961	3 699	2 414	2 431	3 146	3 477	3 903	1 790	1 642	32 956
Mitigation	-	-	-	-	-	-	4 800	-	-	-	-	-	-	-	4 800
Capitalized Interest	-	(1)	-	3 434	5 740	8 120	10 087	12 187	14 019	15 496	16 716	18 921	19 633	15 027	139 379
	197	8 478	28 098	32 636	34 030	33 429	35 169	29 724	28 203	30 733	40 496	36 471	23 778	17 793	$ 379 235

REFERENCE:

PUB/MH I-22

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please refile IFF16 Update with Interim assuming the costs related to Conawapa are written off and are not recovered through a regulatory deferral asset, indicated rate increases are to remain the same.

RATIONALE FOR QUESTION:

RESPONSE:

The following projected financial statements provide a scenario based on MH16 Update with Interim where the costs related to Conawapa are written off to Other Expenses in 2020 and not recovered through a regulatory deferral asset. The write-off results in a $161 million loss in 2020 and a 1-year delay in restoring Manitoba Hydro's capital structure to 25% equity to 2028 absent any compensating adjustment to the indicative profile of rate increases in the 2024/25 to 2026/27 time frame.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	881	1 114	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(28)	(22)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	152	159	164	173	173	174	174	174
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 653	2 390	2 505	2 820	2 891	2 902	2 885	2 887
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(255)	285	465	403	472	584	541	627
Net Movement in Regulatory Deferral	66	72	114	96	84	76	55	(35)	(37)	(36)	(32)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	(159)	368	541	458	437	547	505	594
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	(161)	363	532	448	426	544	503	591
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**(161)**	**363**	**532**	**448**	**426**	**544**	**503**	**591**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	(159)	368	541	458	437	547	505	594
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	13%	14%	15%	16%	18%	20%	22%	24%
EBITDA Interest Coverage	1.51	1.54	1.71	1.36	1.85	2.02	2.03	2.08	2.22	2.24	2.37
Capital Coverage	1.53	1.40	1.48	1.48	1.88	2.35	2.25	2.37	2.34	2.20	2.30

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	907	850	799	739	665	607
Finance Income	(29)	(47)	(57)	(17)	(20)	(19)	(24)	(27)	(46)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	176	177	178	179	180	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 892	2 890	2 886	2 876	2 831	2 815	2 789	2 755	2 707
Net Income before Net Movement in Reg. Deferral	699	803	917	1 034	1 191	1 322	1 468	1 630	1 721
Net Movement in Regulatory Deferral	(31)	(28)	(22)	(20)	(18)	(15)	(16)	(16)	(17)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	668	775	895	1 014	1 172	1 307	1 453	1 614	1 703
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	664	770	887	1 004	1 161	1 295	1 438	1 599	1 687
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**664**	**770**	**887**	**1 004**	**1 161**	**1 295**	**1 438**	**1 599**	**1 687**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	668	775	895	1 014	1 172	1 307	1 453	1 614	1 703
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	27%	29%	33%	37%	41%	46%	51%	57%	64%
EBITDA Interest Coverage	2.49	2.65	2.85	3.09	3.46	3.80	4.27	4.90	5.58
Capital Coverage	2.39	2.47	2.68	2.71	2.94	3.08	3.25	3.17	3.24

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 499	2 572	1 952	1 784	2 002	2 245	2 102	2 217
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 454	30 064	30 132	30 205	30 373	30 557	30 367	30 442
Regulatory Deferral Balance	462	533	647	743	827	903	959	924	887	851	818
	21 733	24 839	27 774	29 197	30 891	31 036	31 163	31 296	31 444	31 217	31 260
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 145	3 024	3 178	3 459	3 980	2 979
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	2 891	3 254	3 787	4 235	4 661	5 205	5 708	6 299
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 148	30 842	30 987	31 115	31 247	31 395	31 168	31 211
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 197	30 891	31 036	31 163	31 296	31 444	31 217	31 260
Net Debt	15 427	18 473	20 743	22 405	23 292	23 600	23 377	22 819	22 186	21 597	20 928
Total Equity	2 856	3 163	3 511	3 403	3 792	4 329	4 461	4 954	5 513	6 030	6 635
Equity Ratio	16%	15%	14%	13%	14%	15%	16%	18%	20%	22%	24%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 844	3 652	2 383	2 065	2 309	2 653	3 457	3 903	5 350
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	31 024	31 803	30 482	30 138	30 346	30 651	31 412	31 875	33 342
Regulatory Deferral Balance	788	760	738	718	700	684	669	653	636
	31 812	32 563	31 220	30 856	31 045	31 335	32 081	32 528	33 978
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 751	14 977	14 080	13 659	13 543
Current and Other Liabilities	2 924	5 274	7 328	5 091	5 146	3 907	4 100	3 360	3 228
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	6 964	7 733	8 620	9 625	10 786	12 080	13 519	15 117	16 805
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	31 763	32 514	31 171	30 807	30 997	31 287	32 032	32 480	33 929
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 812	32 563	31 220	30 856	31 045	31 335	32 081	32 528	33 978
Net Debt	20 177	19 335	18 362	17 302	16 063	14 697	13 172	11 552	9 836
Total Equity	7 314	8 090	8 984	9 996	11 166	12 469	13 916	15 524	17 221
Equity Ratio	27%	29%	33%	37%	41%	46%	51%	57%	64%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(868)	(883)	(892)	(902)	(934)	(951)	(951)	(965)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(830)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	15
	810	734	767	761	963	1 174	1 173	1 289	1 439	1 410	1 514
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(16)	21	(230)	148	(14)	297	(281)	73
Cash at Beginning of Year	943	634	488	562	546	567	337	485	471	769	487
Cash at End of Year	634	488	562	546	567	337	485	471	769	487	560

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH II-12d
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(979)	(995)	(1 011)	(1 034)	(1 029)	(1 042)	(1 062)	(1 086)	(1 096)
Interest Paid	(1 019)	(1 014)	(997)	(909)	(833)	(799)	(742)	(685)	(622)
Interest Received	26	51	64	19	16	22	34	44	63
	1 606	1 722	1 845	1 973	2 161	2 304	2 473	2 644	2 758
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 150	1 140	160	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(194)	(192)	(188)	(187)	(182)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 222)	(1 219)	(904)	(1 381)	(207)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	507	595	(1 227)	(41)	26	158	629	247	1 519
Cash at Beginning of Year	560	1 067	1 662	435	394	420	577	1 206	1 453
Cash at End of Year	1 067	1 662	435	394	420	577	1 206	1 453	2 971

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ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
GCR at Approved Rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
Proposed Rate Increases	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1 194	1 326	1 334	1 349
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 956	2 044	2 317	2 471	2 920	3 150	3 239	3 304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	11%	10%	10%
Interest Coverage	1.16	1.16	1.07	1.06	0.92	0.91	0.86	0.85	0.86	0.91
Capital Coverage	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22

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ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
GCR at Approved Rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
Proposed Rate Increases	734	832	935	1 043	1 157	1 280	1 409	1 486	1 566	1 649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 298	3 342	3 475	3 575	3 702	3 849	3 980	4 065	4 145	4 248
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 351	1 348	1 338	1 337	1 321	1 301	1 263	1 197	1 161	1 116
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 346	3 365	3 388	3 415	3 430	3 439	3 432	3 403	3 403	3 404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%
Financial Ratios										
Equity	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.71
Capital Coverage	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 598	2 727	2 167	2 238	2 442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 668	28 299	27 727	27 788	27 965
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 097	3 069	2 214	2 654	2 604	2 104	2 028	2 101
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 837	2 902	2 812	2 696	2 518	2 312	2 126	2 001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 668	28 299	27 727	27 788	27 965

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ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 387	2 536	2 801	3 049	3 421	3 773	3 629	4 288	4 963	5 703
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189
LIABILITIES AND EQUITY										
Long-Term Debt	23 395	24 198	24 401	24 343	24 476	23 749	23 739	23 743	23 737	23 381
Current and Other Liabilities	2 112	1 443	1 373	1 456	1 372	1 968	1 243	1 199	1 132	1 446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 948	1 924	2 007	2 161	2 427	2 826	3 361	4 008	4 732	5 557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189

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ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1 222)	(1 349)	(1 329)	(1 341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 302)	(1 144)	(980)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

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ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 295	3 340	3 472	3 572	3 699	3 846	3 977	4 062	4 142	4 245
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 348)	(1 353)	(1 354)	(1 371)	(1 368)	(1 360)	(1 341)	(1 250)	(1 230)	(1 200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1 024	1 146	1 288	1 432	1 561	1 655	1 775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	403	161	(37)	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 045)	(1 051)	(1 056)	(1 062)	(1 091)	(1 087)	(1 134)	(1 125)	(1 182)	(1 275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1 390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1 390	1 844

19.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH15)

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES										
General Consumers										
at approved rates	1 517	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610
additional*	0	61	125	191	258	335	411	493	580	672
BPIII Reserve Account	(54)	(67)	(69)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	118	119	32	32	33
	1 887	1 985	2 086	2 225	2 465	2 844	3 066	3 087	3 191	3 301
EXPENSES										
Operating and Administrative	542	552	557	571	585	601	607	619	631	644
Finance Expense	566	588	579	715	823	1 079	1 188	1 180	1 181	1 176
Depreciation and Amortization	410	426	450	535	589	690	742	762	781	800
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	107	122	136	145	146	149	157	157	163	165
Other Expenses	2	2	2	2	2	2	2	3	3	3
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 882	1 965	2 027	2 269	2 443	2 860	3 059	3 087	3 129	3 169
Non-controlling Interest	10	9	4	3	0	2	(1)	(3)	(5)	(3)
Net Income	15	29	63	(41)	21	(13)	6	(4)	56	129
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	15%	14%	14%	13%	13%	13%	12%	12%	12%	13%
Interest Coverage	1.02	1.03	1.06	0.96	1.02	0.99	1.00	1.00	1.05	1.11
EBITDA Interest Coverage	1.57	1.52	1.52	1.46	1.54	1.57	1.62	1.63	1.70	1.78
Capital Coverage	0.98	0.98	1.21	1.05	1.06	1.13	1.32	1.49	1.59	1.60

* Approved financial targets are for consolidated operations only but financial ratios have been provided for electric operations for information purposes.

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES										
General Consumers										
at approved rates	1 626	1 641	1 655	1 669	1 683	1 706	1 734	1 763	1 795	1 831
additional*	769	872	979	1 093	1 158	1 231	1 311	1 395	1 485	1 581
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3 313	3 450	3 545	3 684	3 772	3 838	3 919	4 004	4 101	4 240
EXPENSES										
Operating and Administrative	657	669	683	697	706	719	733	748	763	778
Finance Expense	1 167	1 157	1 134	1 113	1 087	1 055	993	963	929	893
Depreciation and Amortization	820	838	854	867	880	893	906	921	941	963
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	166	167	168	169	171	172	173	175	177	179
Other Expenses	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3 183	3 215	3 222	3 239	3 243	3 234	3 211	3 219	3 234	3 274
Non-controlling Interest	(1)	(2)	(4)	(5)	(8)	(11)	(14)	(16)	(19)	(20)
Net Income	129	232	319	439	520	592	694	769	849	946
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	68.78%	72.15%	75.60%	79.11%	82.69%	86.35%
Financial Ratios										
Equity	13%	14%	16%	17%	20%	22%	25%	28%	31%	35%
Interest Coverage	1.11	1.20	1.28	1.39	1.47	1.56	1.69	1.79	1.90	2.04
EBITDA Interest Coverage	1.81	1.92	2.03	2.16	2.28	2.40	2.60	2.74	2.91	3.11
Capital Coverage	1.61	1.78	1.91	2.03	2.22	2.20	2.35	2.45	2.54	2.45

* Approved financial targets are for consolidated operations only but financial ratios have been provided for electric operations for information purposes.

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ASSETS										
Plant in Service	12 702	13 384	14 151	19 119	22 740	27 521	28 289	28 981	29 672	30 356
Accumulated Depreciation	(697)	(1 056)	(1 428)	(1 871)	(2 352)	(2 926)	(3 543)	(4 171)	(4 818)	(5 470)
Net Plant in Service	12 005	12 328	12 723	17 248	20 388	24 595	24 746	24 810	24 855	24 886
Construction in Progress	4 880	7 548	9 242	6 227	4 001	192	242	223	179	181
Current and Other Assets	2 392	2 654	2 914	3 086	3 093	2 820	2 015	2 387	2 649	2 637
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Regulated Assets	277	298	753	787	811	831	850	839	817	796
	19 791	23 115	26 028	27 911	28 967	29 390	28 768	29 140	29 347	29 313
LIABILITIES AND EQUITY										
Long-Term Debt	14 487	17 586	19 499	21 929	22 429	22 808	22 763	23 257	23 237	22 725
Current and Other Liabilities	2 889	3 005	3 586	2 965	3 502	3 550	3 022	2 888	3 043	3 378
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	239	260	174	87	-	-	-	-
Retained Earnings	2 612	2 641	2 703	2 663	2 684	2 671	2 677	2 673	2 729	2 858
Accumulated Other Comprehensive Income	(771)	(780)	(512)	(438)	(388)	(305)	(285)	(282)	(282)	(281)
	19 791	23 115	26 028	27 911	28 967	29 390	28 768	29 140	29 347	29 313

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS										
Plant in Service	31 081	31 760	32 474	33 199	33 909	34 645	35 389	36 152	36 984	37 813
Accumulated Depreciation	(6 141)	(6 818)	(7 513)	(8 216)	(8 936)	(9 677)	(10 405)	(11 151)	(11 930)	(12 671)
Net Plant in Service	24 941	24 942	24 961	24 983	24 973	24 968	24 984	25 001	25 054	25 142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2 690	3 198	3 608	4 069	4 601	4 579	5 349	6 155	7 034	7 854
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Regulated Assets	778	761	750	747	745	748	755	763	774	786
	29 335	29 821	30 198	30 638	31 114	31 072	31 822	32 620	33 537	34 542
LIABILITIES AND EQUITY										
Long-Term Debt	23 293	23 495	23 437	23 360	22 632	22 622	22 625	22 619	22 622	20 941
Current and Other Liabilities	2 688	2 726	2 829	2 895	3 565	2 927	2 966	2 987	3 038	4 763
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 987	3 219	3 538	3 977	4 497	5 089	5 784	6 553	7 402	8 348
Accumulated Other Comprehensive Income	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
	29 335	29 821	30 198	30 638	31 114	31 072	31 822	32 620	33 537	34 542

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 974	2 041	2 145	2 235	2 367	2 745	2 966	3 074	3 178	3 288
Cash Paid to Suppliers and Employees	(855)	(898)	(944)	(963)	(975)	(1 034)	(1 066)	(1 088)	(1 109)	(1 134)
Interest Paid	(561)	(547)	(551)	(716)	(831)	(1 085)	(1 184)	(1 155)	(1 163)	(1 163)
Interest Received	9	3	11	19	22	19	17	2	2	5
	567	599	662	576	583	646	734	834	908	997
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 457	3 370	2 970	2 800	1 390	1 190	400	780	380	190
Sinking Fund Withdrawals	114	62	-	244	194	296	754	174	14	293
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	2 292	3 078	2 605	2 014	1 220	505	356	446	54	22
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 614)	(3 437)	(3 085)	(2 211)	(1 645)	(1 149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(220)	(247)	(271)	(328)	(200)	(246)	(259)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2 768)	(3 632)	(3 362)	(2 452)	(1 912)	(1 452)	(1 188)	(962)	(972)	(1 036)
Net Increase (Decrease) in Cash	91	44	(95)	138	(110)	(301)	(98)	318	(10)	(17)
Cash at Beginning of Year	482	573	617	521	659	550	248	150	468	458
Cash at End of Year	573	617	521	659	550	248	150	468	458	440

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 300	3 436	3 531	3 670	3 758	3 823	3 904	3 989	4 086	4 225
Cash Paid to Suppliers and Employees	(1 136)	(1 159)	(1 171)	(1 195)	(1 214)	(1 225)	(1 249)	(1 272)	(1 299)	(1 351)
Interest Paid	(1 163)	(1 154)	(1 153)	(1 147)	(1 128)	(1 110)	(1 027)	(1 009)	(988)	(966)
Interest Received	6	14	30	42	50	61	42	54	66	79
	1 007	1 137	1 237	1 370	1 466	1 549	1 671	1 762	1 866	1 987
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	550	190	(10)	(10)	(30)	(10)	(10)	(30)	(30)	(50)
Sinking Fund Withdrawals	98	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	(114)	144	(55)	(54)	(42)	(52)	(51)	(39)	(46)	(57)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1 108)
Sinking Fund Payment	(255)	(260)	(272)	(283)	(292)	(298)	(275)	(285)	(295)	(307)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1 043)	(1 075)	(1 087)	(1 121)	(1 108)	(1 162)	(1 153)	(1 189)	(1 265)	(1 445)
Net Increase (Decrease) in Cash	(150)	206	95	195	316	335	467	534	555	485
Cash at Beginning of Year	440	291	497	592	787	1 103	1 437	1 905	2 439	2 994
Cash at End of Year	291	497	592	787	1 103	1 437	1 905	2 439	2 994	3 479

Financial Information MFR 1 - Alternate Scenario

Resubmit electric-only IFF15 Scenario 2 to show equal annual rate increases that result in a 75:25 debt-to-equity ratio at the end of fiscal year 2033/34.

Response:

Please see attached Scenario 2(c) projected financial statements for electric operations assuming 3.36% even annual rate increases from 2016/17 to 2033/34 to achieve a debt-to-equity ratio of 75:25 by 2033/34, assuming the amortization of the regulatory asset through other comprehensive income. As outlined in the initial response to Financial Information MFR 1 (Attachment 28), Manitoba Hydro's position is that the amortization of regulatory deferral balances through other comprehensive income is an inappropriate accounting treatment.

The reduction in the rate increases from the projected 3.95% in MH15 results in a further increase in net debt along with a corresponding increase in annual finance expense. The increase in net debt is the result of reductions in annual cash inflows from lower revenues in addition to increased cash outflows related to higher finance charges. Scenario 2(c) demonstrates that, while projected net income and retained earnings are initially higher in the six year period to 2020/21, the 59 basis point reduction in annual even rate increases, through 2033/34, compared to MH15 results in net debt that is higher throughout the twenty year forecast period with lower equity levels beginning in 2024/25 through to 2034/35. By 2034/35, net debt is $2.5 billion higher than MH15, resulting in a cumulative increase in finance expense of $809 million compared to MH15.

Compared to Scenario 2 in Financial Information MFR 1 (Attachment 28), this scenario further increases the risk to future rate payers of rate instability and intergenerational inequity. The impact of reduced revenues in combination with increases in finance expense results in a cumulative reduction to retained earnings of $2.5 billion by 2034/35. Should unfavourable conditions such as low water flows or higher interest rates occur, Manitoba Hydro will have reduced capacity in equity to absorb the resulting reductions in earnings increasing the likelihood that customer rates would need to be significantly higher than those projected in MH15. Under this scenario, not only will future ratepayers be responsible for the recovery of $1.9 billion in regulatory deferral accounts by 2034/35 (consistent with Scenario 2 of Financial Information MFR 1), these same ratepayers may also be required to share a larger burden of the financial impact of the various risks the Corporation faces.

To be consistent with the initial response to Financial Information MFR 1 (Attachment 28), Manitoba Hydro has also provided Scenario 1(c). Under this scenario the regulatory asset is amortized through Depreciation & Amortization and the even annual rate increase from 2016/17 to 2033/34 to achieve a debt-to-equity ratio of 75:25 by 2033/34 is 3.36%, the same as Scenario 2(c). Regardless of the regulatory asset amortization assumption through either income or other comprehensive income both affect equity and the debt-to-equity ratio equally through either retained earnings or AOCI, respectively, and result in the same impact to the calculated even annual rate increases under both Scenario 1 and Scenario 2. Likewise, the reduction of even annual rate increases under Scenario 1(c) results in the same increase in net debt of $2.5 billion to 2034/35 and the increased risk of rate instability to customers as Scenario 2(c). Scenario 1(c) is also attached.

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
Financial Information MFR #1 - Scenario 2 (OCI Scenario) - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES										
General Consumers										
at approved rates	1 517	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610
additional*	0	52	106	162	218	282	345	412	483	558
BPIII Reserve Account	(54)	(66)	(68)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	117	118	32	32	33
	1 887	1 976	2 068	2 196	2 424	2 791	2 999	3 006	3 094	3 187
EXPENSES										
Operating and Administrative	522	532	537	551	565	581	587	599	611	624
Finance Expense	566	588	580	718	827	1 085	1 198	1 195	1 201	1 201
Depreciation and Amortization	379	393	416	495	546	640	688	707	725	743
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	108	123	137	146	147	150	157	158	166	167
Other Expenses	2	2	2	2	2	2	2	3	3	3
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 831	1 913	1 976	2 213	2 385	2 796	2 995	3 028	3 075	3 120
Non-controlling Interest	10	9	4	3	0	2	(1)	(3)	(5)	(3)
Net Income	66	72	96	(14)	39	(4)	2	(26)	13	65
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%
Cumulative Percent Increase	0.00%	3.36%	6.84%	10.43%	14.14%	17.98%	21.95%	26.05%	30.28%	34.66%
Financial Ratios										
Equity	16%	14%	15%	14%	14%	13%	12%	12%	12%	12%
Interest Coverage	1.09	1.08	1.10	0.99	1.03	1.00	1.00	0.98	1.01	1.05
EBITDA Interest Coverage	1.60	1.53	1.52	1.45	1.52	1.53	1.57	1.56	1.61	1.67
Capital Coverage	0.98	0.97	1.17	1.00	0.99	1.01	1.18	1.32	1.39	1.38

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
Financial Information MFR #1 - Scenario 2 (OCI Scenario) - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
REVENUES										
General Consumers										
at approved rates	1 626	1 641	1 655	1 669	1 683	1 706	1 734	1 763	1 795	1 831
additional*	637	720	806	896	991	1 095	1 209	1 330	1 460	1 556
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3 181	3 298	3 372	3 487	3 605	3 702	3 817	3 940	4 077	4 215
EXPENSES										
Operating and Administrative	637	649	663	677	686	699	713	728	743	758
Finance Expense	1 201	1 201	1 187	1 179	1 162	1 136	1 080	1 054	1 025	992
Depreciation and Amortization	761	777	793	804	815	827	839	852	871	891
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	169	170	172	173	174	176	178	179	181	183
Other Expenses	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3 142	3 182	3 198	3 225	3 237	3 233	3 214	3 226	3 243	3 286
Non-controlling Interest	(1)	(2)	(4)	(5)	(8)	(11)	(14)	(16)	(19)	(20)
Net Income	38	113	170	256	360	458	589	697	815	909
Other Comprehensive Income	(22)	(25)	(28)	(30)	(33)	(36)	(38)	(41)	(44)	(46)
Comprehensive Income	16	88	142	226	327	422	551	656	771	862
* Additional General Consumers Revenue										
Percent Increase	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	2.00%
Cumulative Percent Increase	39.19%	43.87%	48.71%	53.71%	58.88%	64.22%	69.74%	75.44%	81.34%	84.97%
Financial Ratios										
Equity	12%	13%	13%	14%	16%	17%	20%	22%	25%	28%
Interest Coverage	1.03	1.09	1.14	1.22	1.31	1.40	1.54	1.66	1.79	1.90
EBITDA Interest Coverage	1.66	1.74	1.80	1.89	2.00	2.12	2.31	2.46	2.63	2.79
Capital Coverage	1.34	1.47	1.56	1.64	1.85	1.89	2.08	2.23	2.37	2.29

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
Financial Information MFR #1 - Scenario 2 (OCI Scenario) - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
ASSETS										
Plant in Service	12 702	13 384	14 151	19 119	22 740	27 521	28 289	28 981	29 672	30 356
Accumulated Depreciation	(697)	(1 056)	(1 428)	(1 871)	(2 352)	(2 926)	(3 543)	(4 171)	(4 818)	(5 470)
Net Plant in Service	12 005	12 328	12 723	17 248	20 388	24 595	24 746	24 810	24 855	24 886
Construction in Progress	4 880	7 548	9 242	6 227	4 001	192	242	223	179	181
Current and Other Assets	2 391	2 643	2 881	3 022	3 186	2 848	2 166	2 242	2 588	2 634
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Regulated Assets	375	445	949	1 034	1 112	1 191	1 270	1 319	1 355	1 390
	19 888	23 251	26 190	28 094	29 362	29 778	29 340	29 474	29 823	29 904
LIABILITIES AND EQUITY										
Long-Term Debt	14 487	17 586	19 499	21 929	22 629	23 003	23 158	23 452	23 632	23 320
Current and Other Liabilities	2 889	3 005	3 585	2 966	3 505	3 548	3 020	2 886	3 045	3 379
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	238	259	173	86	-	-	-	-
Retained Earnings	2 712	2 784	2 880	2 866	2 905	2 902	2 904	2 878	2 891	2 956
Accumulated Other Comprehensive Income	(773)	(786)	(524)	(458)	(416)	(340)	(333)	(347)	(364)	(384)
	19 888	23 251	26 190	28 094	29 362	29 778	29 340	29 474	29 823	29 904

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
Financial Information MFR #1 - Scenario 2 (OCI Scenario) - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS										
Plant in Service	31 081	31 760	32 474	33 199	33 909	34 645	35 389	36 152	36 984	37 813
Accumulated Depreciation	(6 141)	(6 818)	(7 513)	(8 216)	(8 936)	(9 677)	(10 405)	(11 151)	(11 930)	(12 671)
Net Plant in Service	24 941	24 942	24 961	24 983	24 973	24 968	24 984	25 001	25 054	25 142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2 715	3 024	3 407	3 807	4 094	3 851	4 429	5 075	5 829	6 521
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Regulated Assets	1 427	1 465	1 508	1 558	1 607	1 660	1 716	1 773	1 830	1 888
	30 010	30 352	30 756	31 187	31 470	31 257	31 864	32 549	33 388	34 310
LIABILITIES AND EQUITY										
Long-Term Debt	24 088	24 290	24 432	24 555	23 827	23 817	23 820	23 814	23 817	22 136
Current and Other Liabilities	2 687	2 725	2 833	2 902	3 572	2 934	2 973	2 994	3 044	4 770
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 994	3 107	3 277	3 533	3 893	4 351	4 940	5 637	6 452	7 361
Accumulated Other Comprehensive Income	(406)	(431)	(459)	(489)	(522)	(558)	(596)	(637)	(681)	(727)
	30 010	30 352	30 756	31 187	31 470	31 257	31 864	32 549	33 388	34 310

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
Financial Information MFR #1 - Scenario 2 (OCI Scenario) - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 974	2 032	2 126	2 206	2 326	2 692	2 900	2 993	3 082	3 175
Cash Paid to Suppliers and Employees	(856)	(899)	(945)	(964)	(976)	(1 035)	(1 066)	(1 089)	(1 111)	(1 137)
Interest Paid	(561)	(547)	(554)	(716)	(832)	(1 096)	(1 194)	(1 169)	(1 180)	(1 188)
Interest Received	9	3	11	19	22	19	17	2	2	5
	567	589	639	545	540	581	657	737	792	855
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 457	3 370	2 970	2 800	1 590	1 190	600	580	580	390
Sinking Fund Withdrawals	114	62	-	244	194	296	754	174	18	295
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	2 292	3 078	2 605	2 014	1 420	505	556	246	258	224
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 614)	(3 437)	(3 085)	(2 211)	(1 645)	(1 149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(220)	(247)	(271)	(328)	(204)	(249)	(263)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2 768)	(3 632)	(3 362)	(2 452)	(1 912)	(1 452)	(1 188)	(966)	(974)	(1 040)
Net Increase (Decrease) in Cash	91	34	(118)	107	48	(366)	25	17	76	39
Cash at Beginning of Year	482	572	606	488	595	643	276	301	318	395
Cash at End of Year	572	606	488	595	643	276	301	318	395	434

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ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
Financial Information MFR #1 - Scenario 2 (OCI Scenario) - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 168	3 284	3 358	3 473	3 591	3 688	3 802	3 925	4 062	4 200
Cash Paid to Suppliers and Employees	(1 139)	(1 163)	(1 175)	(1 199)	(1 218)	(1 229)	(1 253)	(1 276)	(1 303)	(1 356)
Interest Paid	(1 200)	(1 198)	(1 203)	(1 210)	(1 204)	(1 193)	(1 116)	(1 104)	(1 087)	(1 070)
Interest Received	6	14	31	44	52	63	45	57	70	84
	835	937	1 010	1 108	1 221	1 328	1 478	1 602	1 742	1 858
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	750	190	190	190	(30)	(10)	(10)	(30)	(30)	(50)
Sinking Fund Withdrawals	102	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	91	144	145	146	(42)	(52)	(51)	(39)	(46)	(57)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1 108)
Sinking Fund Payment	(261)	(268)	(281)	(295)	(305)	(312)	(289)	(300)	(310)	(323)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1 049)	(1 083)	(1 097)	(1 133)	(1 122)	(1 176)	(1 167)	(1 204)	(1 281)	(1 461)
Net Increase (Decrease) in Cash	(124)	(1)	59	122	57	100	260	359	415	340
Cash at Beginning of Year	434	310	309	368	490	548	648	908	1 267	1 682
Cash at End of Year	310	309	368	490	548	648	908	1 267	1 682	2 023

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
Financial Information MFR #1 - Scenario 1 - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
REVENUES										
General Consumers										
at approved rates	1 517	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610
additional*	0	52	106	162	218	282	345	412	483	558
BPIII Reserve Account	(54)	(66)	(68)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	117	118	32	32	33
	1 887	1 976	2 068	2 196	2 424	2 791	2 999	3 006	3 094	3 187
EXPENSES										
Operating and Administrative	522	532	537	551	565	581	587	599	611	624
Finance Expense	566	588	580	718	827	1 085	1 198	1 195	1 201	1 201
Depreciation and Amortization	381	397	421	503	555	652	701	723	743	763
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	108	123	137	146	147	150	157	158	166	167
Other Expenses	2	2	2	2	2	2	2	3	3	3
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 834	1 917	1 981	2 220	2 394	2 808	3 009	3 044	3 094	3 141
Non-controlling Interest	10	9	4	3	0	2	(1)	(3)	(5)	(3)
Net Income	63	68	90	(21)	30	(15)	(11)	(42)	(5)	44
Other Comprehensive Income	(51)	(9)	105	45	36	65	5	2	1	1
Comprehensive Income	13	59	195	23	66	50	(6)	(39)	(4)	45
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%
Cumulative Percent Increase	0.00%	3.36%	6.84%	10.43%	14.14%	17.98%	21.95%	26.05%	30.29%	34.67%
Financial Ratios										
Equity	16%	14%	15%	14%	14%	13%	12%	12%	12%	12%
Interest Coverage	1.09	1.08	1.09	0.98	1.03	0.99	0.99	0.97	1.00	1.04
EBITDA Interest Coverage	1.60	1.53	1.52	1.45	1.52	1.53	1.57	1.56	1.61	1.67
Capital Coverage	0.98	0.97	1.17	1.00	0.99	1.01	1.18	1.32	1.39	1.38

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
Financial Information MFR #1 - Scenario 1 - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
REVENUES										
General Consumers										
at approved rates	1 626	1 641	1 655	1 669	1 683	1 706	1 734	1 763	1 795	1 831
additional*	637	720	806	897	991	1 096	1 210	1 331	1 461	1 556
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3 181	3 298	3 372	3 487	3 606	3 702	3 817	3 940	4 077	4 215
EXPENSES										
Operating and Administrative	637	649	663	677	686	699	713	728	743	758
Finance Expense	1 201	1 201	1 187	1 179	1 162	1 136	1 080	1 054	1 025	992
Depreciation and Amortization	784	803	821	834	848	863	877	893	915	938
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	169	170	172	173	175	176	178	179	181	184
Other Expenses	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3 165	3 208	3 226	3 256	3 270	3 269	3 253	3 267	3 287	3 332
Non-controlling Interest	(1)	(2)	(4)	(5)	(8)	(11)	(14)	(16)	(19)	(20)
Net Income	15	88	142	226	327	422	551	656	771	862
Other Comprehensive Income	1	-	-	-	-	-	-	-	-	-
Comprehensive Income	16	88	142	226	327	422	551	656	771	862
* Additional General Consumers Revenue										
Percent Increase	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	3.36%	2.00%
Cumulative Percent Increase	39.20%	43.88%	48.71%	53.71%	58.88%	64.23%	69.75%	75.45%	81.35%	84.98%
Financial Ratios										
Equity	12%	13%	13%	14%	16%	17%	20%	22%	25%	28%
Interest Coverage	1.01	1.07	1.12	1.19	1.28	1.37	1.51	1.62	1.75	1.86
EBITDA Interest Coverage	1.66	1.74	1.80	1.89	2.00	2.12	2.31	2.46	2.63	2.79
Capital Coverage	1.34	1.47	1.56	1.64	1.85	1.89	2.08	2.23	2.37	2.29

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
Financial Information MFR #1 - Scenario 1 - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ASSETS										
Plant in Service	12 702	13 384	14 151	19 119	22 740	27 521	28 289	28 981	29 672	30 356
Accumulated Depreciation	(697)	(1 056)	(1 428)	(1 871)	(2 352)	(2 926)	(3 543)	(4 171)	(4 818)	(5 470)
Net Plant in Service	12 005	12 328	12 723	17 248	20 388	24 595	24 746	24 810	24 855	24 886
Construction in Progress	4 880	7 548	9 242	6 227	4 001	192	242	223	179	181
Current and Other Assets	2 391	2 643	2 881	3 022	3 186	2 848	2 166	2 242	2 588	2 634
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Regulated Assets	375	445	949	1 034	1 112	1 191	1 270	1 319	1 355	1 390
	19 888	23 251	26 190	28 094	29 362	29 778	29 340	29 474	29 823	29 904
LIABILITIES AND EQUITY										
Long-Term Debt	14 487	17 586	19 499	21 929	22 629	23 003	23 158	23 452	23 632	23 320
Current and Other Liabilities	2 889	3 005	3 585	2 966	3 505	3 548	3 020	2 886	3 045	3 379
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	238	259	173	86	-	-	-	-
Retained Earnings	2 709	2 778	2 868	2 847	2 876	2 862	2 850	2 808	2 804	2 848
Accumulated Other Comprehensive Income	(771)	(780)	(512)	(438)	(388)	(300)	(280)	(277)	(276)	(276)
	19 888	23 251	26 190	28 094	29 362	29 778	29 340	29 474	29 823	29 904

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
Financial Information MFR #1 - Scenario 1 - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS										
Plant in Service	31 081	31 760	32 474	33 199	33 909	34 645	35 389	36 152	36 984	37 813
Accumulated Depreciation	(6 141)	(6 818)	(7 513)	(8 216)	(8 936)	(9 677)	(10 405)	(11 151)	(11 930)	(12 671)
Net Plant in Service	24 941	24 942	24 961	24 983	24 973	24 968	24 984	25 001	25 054	25 142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2 715	3 024	3 407	3 807	4 094	3 851	4 429	5 075	5 829	6 521
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Regulated Assets	1 427	1 465	1 508	1 558	1 607	1 660	1 716	1 773	1 830	1 888
	30 010	30 352	30 756	31 187	31 470	31 257	31 864	32 549	33 388	34 310
LIABILITIES AND EQUITY										
Long-Term Debt	24 088	24 290	24 432	24 555	23 827	23 817	23 820	23 814	23 817	22 136
Current and Other Liabilities	2 687	2 725	2 833	2 902	3 572	2 934	2 973	2 994	3 044	4 770
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 863	2 951	3 093	3 319	3 646	4 068	4 619	5 275	6 046	6 908
Accumulated Other Comprehensive Income	(275)	(275)	(275)	(275)	(275)	(275)	(275)	(275)	(275)	(275)
	30 010	30 352	30 756	31 187	31 470	31 257	31 864	32 549	33 388	34 310

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
Financial Information MFR #1 - Scenario 1 - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 974	2 032	2 126	2 206	2 326	2 692	2 900	2 993	3 082	3 175
Cash Paid to Suppliers and Employees	(856)	(899)	(945)	(964)	(976)	(1 035)	(1 066)	(1 089)	(1 111)	(1 137)
Interest Paid	(561)	(547)	(554)	(716)	(832)	(1 096)	(1 194)	(1 169)	(1 180)	(1 188)
Interest Received	9	3	11	19	22	19	17	2	2	5
	567	589	639	545	540	581	657	737	792	855
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 457	3 370	2 970	2 800	1 590	1 190	600	580	580	390
Sinking Fund Withdrawals	114	62	-	244	194	296	754	174	18	295
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	2 292	3 078	2 605	2 014	1 420	505	556	246	258	224
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 614)	(3 437)	(3 085)	(2 211)	(1 645)	(1 149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(220)	(247)	(271)	(328)	(204)	(249)	(263)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2 768)	(3 632)	(3 362)	(2 452)	(1 912)	(1 452)	(1 188)	(966)	(974)	(1 040)
Net Increase (Decrease) in Cash	91	34	(118)	107	48	(366)	25	17	76	39
Cash at Beginning of Year	482	572	606	488	595	643	276	301	318	395
Cash at End of Year	572	606	488	595	643	276	301	318	395	434

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
Financial Information MFR #1 - Scenario 1 - Alternate Scenario
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 168	3 284	3 358	3 473	3 591	3 688	3 802	3 925	4 062	4 200
Cash Paid to Suppliers and Employees	(1 139)	(1 163)	(1 175)	(1 199)	(1 218)	(1 229)	(1 253)	(1 276)	(1 303)	(1 356)
Interest Paid	(1 200)	(1 198)	(1 203)	(1 210)	(1 204)	(1 193)	(1 116)	(1 104)	(1 087)	(1 070)
Interest Received	6	14	31	44	52	63	45	57	70	84
	835	938	1 011	1 108	1 221	1 328	1 478	1 602	1 742	1 858
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	750	190	190	190	(30)	(10)	(10)	(30)	(30)	(50)
Sinking Fund Withdrawals	102	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	91	144	145	146	(42)	(52)	(51)	(39)	(46)	(57)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1 108)
Sinking Fund Payment	(261)	(268)	(281)	(295)	(305)	(312)	(289)	(300)	(310)	(323)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1 049)	(1 083)	(1 097)	(1 133)	(1 122)	(1 176)	(1 167)	(1 204)	(1 281)	(1 461)
Net Increase (Decrease) in Cash	(124)	(1)	59	122	57	100	260	359	415	340
Cash at Beginning of Year	434	310	309	368	490	548	648	908	1 267	1 682
Cash at End of Year	310	309	368	490	548	648	908	1 267	1 682	2 022

SUPPLEMENTAL FILING TO
MANITOBA HYDRO'S 2015/16 & 2016/17 GENERAL RATE APPLICATION

1.0 OVERVIEW

On January 16, 2015, Manitoba Hydro applied to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to Section 26(1) of *The Crown Corporations Public Review and Accountability Act* and pursuant to Section 47(2) of *The Public Utilities Board Act* for approval of a 3.95% general rate increase effective April 1, 2016.

Manitoba Hydro filed a comprehensive 2015/16 & 2016/17 General Rate Application ("GRA") on January 23, 2015 which outlined in detail the capital investment drivers and borrowing requirements as well as the compelling need for steady and regular rate increase over the next decade. The information filed was extensively reviewed and tested by the parties to the GRA over the course of five months. In Order 73/15, the PUB indicated it would consider options regarding a process to review rates for April 1, 2016.

In this Supplemental Filing to the 2015/16 & 2016/17 GRA, Manitoba Hydro is requesting that the 2016/17 rate increase of 3.95% contained in the GRA be approved on an interim basis effective April 1, 2016. This increase, applied on an across-the-board basis for all customer classes, is projected to generate additional revenues of $61 million and result in a modest contribution to financial reserves (net income) of $29 million in 2016/17. Absent the proposed rate increase for 2016/17, Manitoba Hydro is projecting a net loss of $33 million from Electric operations and financial ratios are projected to deteriorate further.

Manitoba Hydro believes that the interim rate increase being requested continues to carefully balance the need for investment to maintain safe and reliable service with the need to provide steady and predictable rates for customers. As the supplemental information provided herein will show, Manitoba Hydro has continued to maintain stable rates through the careful management and spending on its assets, as well as managing its operating and administrative costs.

The reasons for the requested 3.95% interim rate increase remain consistent with those outlined by Manitoba Hydro in the 2015/16 & 2016/17 GRA, and include the following:

- Manitoba Hydro is in a period of extensive capital investment to meet the growing energy requirements of Manitoba, to replace aging utility assets, and address increased capacity needs on the system.

- The required investment in new and existing infrastructure is expected to nearly double the asset base and associated carrying costs (revenue requirements) of Electric operations in the next 10 years.
- Rate stability for customers is dependent upon Manitoba Hydro maintaining its financial strength. The required investment in assets will place pressure on Manitoba Hydro's financial strength by deteriorating the financial results and key financial ratios.
- Manitoba Hydro continues to experience downward pressure on electricity prices in the export market and it is necessary to gradually increase rates over time to compensate for the resulting reduction in net extraprovincial revenues.
- Manitoba Hydro's 2016/17 rate proposal maintains net income and financial ratios at acceptable levels and is necessary to promote rate stability for customers and manage the deterioration of the Corporation's financial strength during this period of extensive capital investment.

In Order 73/15, the PUB made a clear policy decision to mitigate rate shock to consumers by phasing rate increases in over time. Manitoba Hydro believes that its interim rate increase request is fully consistent with the PUB's policy decision to gradually increase rates during this period of extensive capital investments. Manitoba Hydro's rates will continue to be competitive compared to other jurisdictions, even with the proposed rate increase.

Manitoba Hydro's Supplemental Filing is organized as follows:

- Section 2.0 provides an overview of the reasons for the requested 3.95% rate increase, as summarized above.
- Section 3.0 and Section 4.0 provide a summary of Manitoba Hydro's current financial position and financial outlook, and a comparison of Manitoba Hydro's current and previous financial forecast. In previous Orders, the PUB expressed concerns about the deterioration of Manitoba Hydro's financial results. In its current forecast, including the impacts of the 3.95% rate increases, Manitoba Hydro is projecting that financial reserves will be stable relative to current levels, reducing the risk of the requirement for higher electric rate increases in the future.
- Section 5.0 provides an overview of the 2015 financial target review and Manitoba Hydro's projected financial ratios. Manitoba Hydro's financial target review, which included an external assessment by KPMG, concluded that Manitoba Hydro's financial targets remain appropriate. Manitoba Hydro will maintain its debt/equity and capital coverage ratios and will adopt an EBITDA interest coverage ratio to replace the current EBIT interest coverage ratio.

Manitoba Hydro is exposed to significant financial volatility, particularly with respect to changes in water flows, interest rates and export prices. Even with 3.95% indicative rate increases, over the next ten years there is a significant likelihood that Manitoba Hydro could incur losses, and retained earnings and the equity ratio could drop below the minimum acceptable levels. Given this volatility, Manitoba Hydro is of the view that the 3.95% proposed and indicative rate increases continue to be the minimum necessary to promote rate stability for customers and manage the deterioration of Manitoba Hydro's financial strength.

- Section 6.0 provides an overview of Manitoba Hydro's Operating and Administrative ("O&A") expense. Manitoba Hydro is effectively controlling its costs to maintain the projected 3.95% rate increases and continues to limit increases in O&A to 1%, excluding the impacts of accounting changes.
- Section 7.0 provides an overview of the current capital expenditure forecast which reflects higher demand side management expenditures and cost flow timing changes due to lower than forecast spending in 2014/15. Manitoba Hydro has started construction of two major generation and transmission projects, investing approximately $1.24 billion in the Bipole III Reliability Project and $1.97 billion in the Keeyask Generating Station as of September 30, 2015.
- Section 8.0 provides updated rate schedules and customer impacts for the proposed rate increase. If approved by the PUB, a residential customer, without electric space heat, using an average of 1,000 kWh per month would experience an increase in their monthly bill of $3.33 for 2016/17. A residential customer with electric space heat, using an average of 2,000 kWh a month, would experience increases of $6.36 per month for April 1, 2016.
- Finally, Section 9.0 provides updated generation, water conditions and extra-provincial energy exchange tables pursuant to Directive 5 of Order 43/13.

2.0 SUMMARY OF THE REASONS FOR THE REQUESTED 3.95% RATE INCREASE

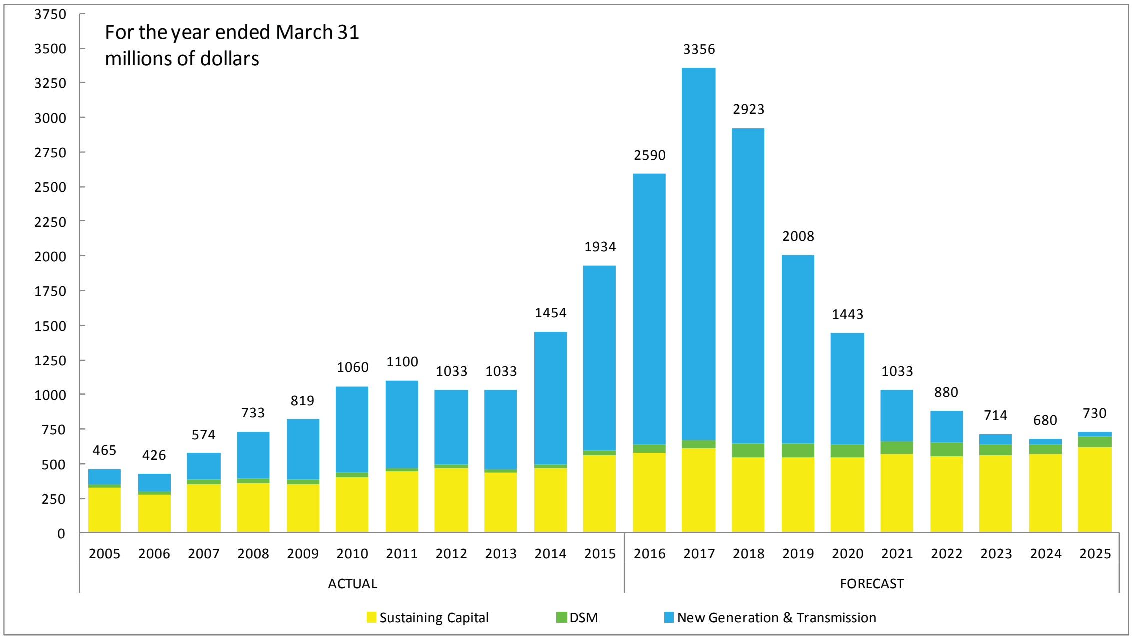
Manitoba Hydro is providing an updated financial forecast (MH15) to provide further context and support for its request for a 3.95% rate increase effective April 1, 2016. MH15 forecasts electricity rate increases of 3.95% to 2028/29 (and 2.0% thereafter to 2034/35) as being the minimum necessary to strike the appropriate balance between the needed investment to maintain safe and reliable service and providing stable and predictable rates for customers, and to manage the deterioration in the Corporation's financial strength. The 3.95% rate increase effective April 1, 2016 is further required to maintain 2016/17 net income and financial ratios at acceptable levels.

2.1 Extensive Electric Capital Investments are Expected to Nearly Double Carrying Costs in the Next 10 Years

As discussed extensively during the public review of the 2015/16 & 2016/17 GRA, Manitoba Hydro is in the midst of a period of extensive capital investment to meet growing energy requirements of Manitoba, replace aging utility assets and address increased capacity constraints on its system.

The level of Manitoba Hydro's capital investments are projected to be significantly higher than in the past ten years, and are unprecedented in Manitoba Hydro's history. The following Figure demonstrates that Manitoba Hydro's capital investments for Electric operations were in excess of $1 billion between 2009/10 and 2012/13, and approximately $1.5 billion in 2013/14 and $1.9 billion in 2014/15. Electric capital investments are projected to be approximately $2.6 billion in 2015/16 and $3.4 billion in 2016/17. Thereafter, capital investments are not expected to return to previous levels until 2022/23.

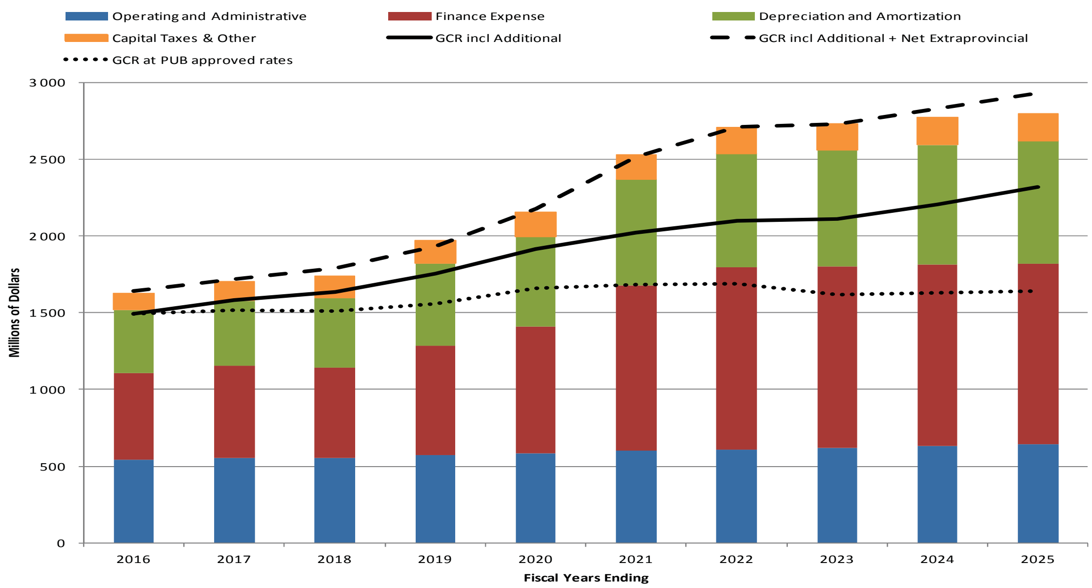
Figure 1. Capital Investments in Electric Operations 2004/05 to 2024/25



As a result of the capital intensive nature of Manitoba Hydro's business, approximately two-thirds of the overall costs or revenue requirement of the Corporation is made up of carrying costs (finance expense, depreciation & capital taxes) of the assets that are used to provide service to customers, along with the operating and administrative (O&A) costs of these assets. Once these assets are placed into service, the associated carrying costs form part of the Corporation's revenue requirements.

The following Figure compares Manitoba Hydro's Electric operations projected non-flow related expenses (O&A, finance expense, depreciation expense, and taxes and other expenses), which are more fixed in nature, to the Corporation's projected domestic and net export revenues (extraprovincial revenues less fuel & power purchases and water rentals & assessments) in MH15.

Figure 2. Electric Expenses Compared to Revenues (MH15)



Manitoba Hydro's costs rise sharply to approximately $2.7 billion over the 10 year period to 2024/25, almost doubling from their current level of $1.6 billion. This increase in costs is primarily driven by Manitoba Hydro's required capital investments.

General Consumers Revenue is insufficient to fully cover the approximately $1.1 billion total cost increase. Over the 10 year period, General Consumers Revenue, including the proposed and indicative 3.95% annual rate increases, rises by slightly less than half (42%) of the cost increase.

Including net extraprovincial revenues, Manitoba Hydro is projecting losses on Electric operations in three out of the ten years in the period 2018/19 to 2024/25 and is forecasting a marginal increase in projected retained earnings from approximately $2.6 billion in 2015/16 to $2.8 billion by 2024/25, while Manitoba Hydro's asset base doubles from approximately $12 billion to $25 billion.

Manitoba Hydro is incurring significant fixed costs associated with major generation and transmission projects and sustaining capital expenditures, and these investments are resulting in increased revenue requirements. Manitoba Hydro's request for an interim electricity rate increase effective April 1, 2016 is consistent with its approach to gradually increase rates during this period of extensive capital investments.

The current environment of significant capital investments necessitates a proactive and longer term approach to rate-setting, which is consistent with the PUB's policy decisions in Order 73/15 to mitigate rate shock to consumers by phasing the required rate increases in over time.

2.2 Investments in Capital Assets Will Place Pressure on Manitoba Hydro's Financial Strength and Increase the Risk of Rate Volatility

The majority of Manitoba Hydro's capital investments will be funded through unprecedented levels of debt financing, and will place pressure on the Corporation's financial strength by deteriorating financial results and key financial ratios.

Due to the increased levels of debt financing and weaker near-term financial results, Manitoba Hydro projects deterioration in the Electric operations equity ratio to 12% by 2021/22 before it gradually begins to recover to reach the 25% equity target by 2031/32. The Electric operations capital coverage ratio is projected to be below target for several years before achieving the 1.20 target by 2021/22, and the revised EBITDA interest coverage ratio target of 1.80 (as discussed in Section 5.1) is expected to be achieved by 2025/26.

The following figures show Manitoba Hydro's projected net income, retained earnings, and financial ratios over the 10-year period to 2024/25 in MH15, including the proposed and indicative 3.95% rate increases.

Figure 3. Projected Electric Net Income

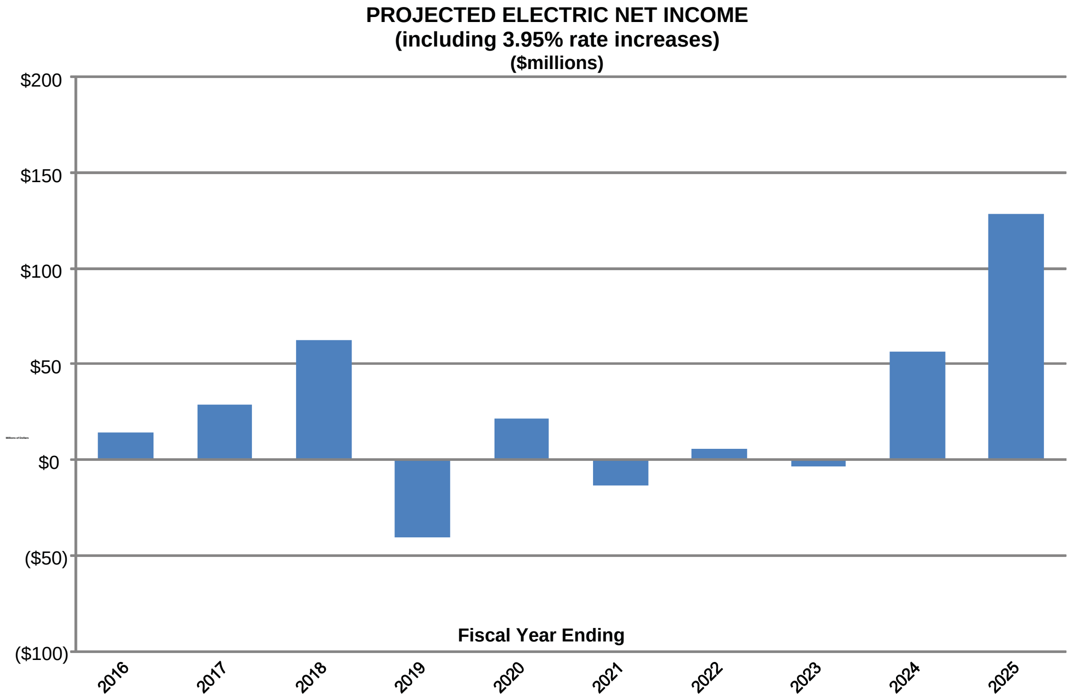
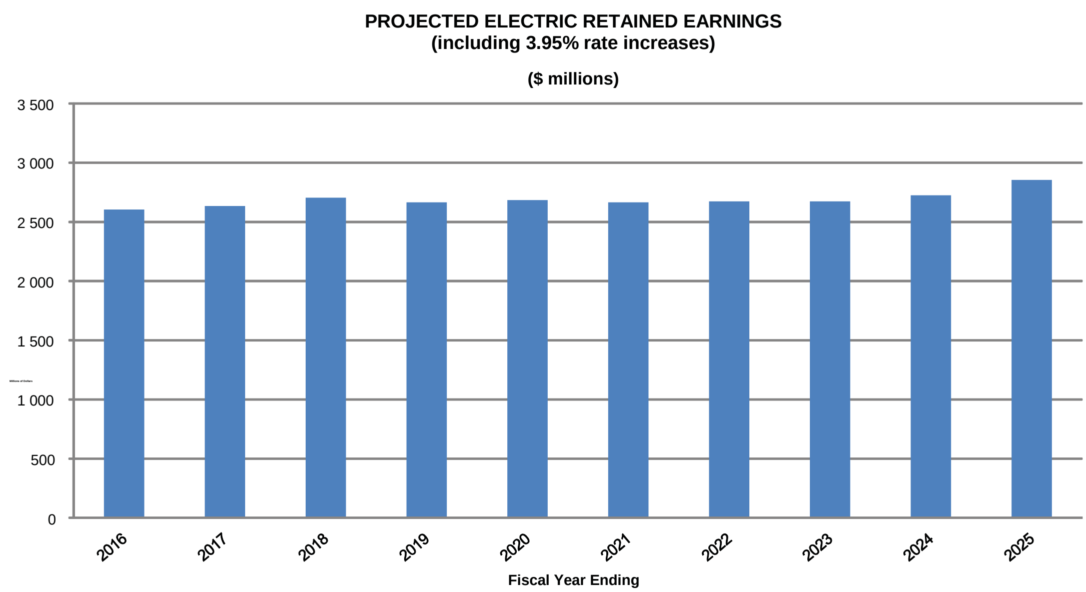


Figure 4. Projected Electric Retained Earnings



Manitoba Hydro - Electricity operations
Comparison of IFF16 to IFF08-1 20 year forecast

Yellow Highlight = Year 75% Debt Equity Ratio Achieved

		2010	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
IFF16 Update with Interim 20 Year Forecast																										
	Annual Increase							3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
IFF16 Update 20 Year Forecast																										
	Annual Increase							7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
IFF16 20 Year Forecast																										
	Annual Increase						0.00%	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
IFF15 20 Year Forecast																										
	Annual Increase					0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	
IFF14 20 Year Forecast																										
	Annual Increase				0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%		
IFF13 20 Year Forecast																										
	Annual Increase			0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%			
IFF12 20 Year Forecast																										
	Annual Increase		0.00%	3.50%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%				
IFF11-2 20 Year Forecast																										
	Annual Increase		3.57%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%				
IFF11 20 Year Forecast																										
	Annual Increase		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%				
IFF10-2 20 Year Forecast																										
	Annual Increase		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%						
IFF10-1 20 Year Forecast																										
	Annual Increase		3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%						
IFF09-1 20 Year Forecast																										
	Annual Increase		3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%								
IFF08-1 20 Year Forecast																										
	Annual Increase	4.00%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%								

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Figure 6.2 Updated - Statement of Income

MANITOBA HYDRO
STATEMENT OF INCOME - ELECTRIC OPERATIONS
(000's)

	CGAAP 2014/15 Actual	IFRS 2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Forecast	2018/19 Forecast
Revenue						
Domestic	1 454 629	1 454 764	1 449 968	1 514 796	1 577 658	1 564 889
Bipole III reserve	(30 249)	(30 249)	(51 203)	(96 018)	(151 016)	1 468
Extraprovincial	383 644	383 644	415 028	460 049	513 940	469 168
Other	18 411	29 752	30 968	27 581	30 313	30 760
Total revenue excluding rate increases	$ 1 826 435	$ 1 837 911	$ 1 844 761	$ 1 906 408	$ 1 970 895	$ 2 066 285
Expenses						
Finance expense	494 541	515 068	581 958	607 790	587 089	676 883
Operating and administrative	480 472	538 404	542 729	535 826	518 340	501 183
Depreciation and amortization	403 453	352 307	366 664	375 261	396 078	470 839
Water rentals and assessments	124 887	124 887	126 086	131 261	130 372	119 962
Fuel and power purchased	129 119	129 119	117 492	131 984	123 512	139 998
Capital and other taxes	99 754	99 754	106 539	118 849	132 072	144 715
Other expenses	2 038	37 045	64 939	60 169	116 362	108 970
Finance income	-	(25 980)	(22 406)	(17 326)	(16 883)	(21 035)
Corporate allocation	8 675	8 492	8 344	8 347	8 347	8 347
Total expenses	1 742 939	1 779 096	1 892 345	1 952 161	1 995 288	2 149 864
Net income (loss) before net movement in regulatory balances	83 496	58 815	(47 584)	(45 753)	(24 393)	(83 579)
Net loss attributable to non-controlling interests*	11 192	-	-	-	-	-
Net movement in regulatory balances	-	41 131	74 342	66 431	71 808	113 540
Non-recurring gain	-	-	-	20 198	-	-
Net Income before rate increases	94 688	99 945	26 758	40 876	47 414	29 961
Proposed rate increases **				-	37 330	179 389
Net income including rate increases	$ 94 688	$ 99 945	$ 26 758	$ 40 876	$ 84 744	$ 209 350
Net income (loss) attributable to:						
Manitoba Hydro	**$ 94 688**	**$ 111 111**	**$ 36 947**	**$ 52 889**	**$ 93 141**	**$ 210 543**
Non-controlling interests*	-	(11 166)	(10 189)	(12 013)	(8 397)	(1 193)
	$ 94 688	$ 99 945	$ 26 758	$ 40 876	$ 84 744	$ 209 350

*Non-controlling interest represents NCN's share of the net income/loss from WPLP.
** 3.36% interim on August 1, 2017 and 7.90% proposed on April 1, 2018

(in millions of Canadian dollars)

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Note 20 Regulatory deferral balances

	March 31, 2016	Balances arising in the year	Recovery / reversal	**March 31, 2017**	Remaining recovery / reversal period
					(years)
Regulatory deferral debit balances					
Electric					
DSM programs[1]	232	56	(35)	**253**	1 - 10
Site restoration	31	1	(4)	**28**	1 - 15
Change in depreciation method	60	31	-	**91**	*
Deferred ineligible overhead	40	21	-	**61**	*
Acquisition costs	10	-	(1)	**9**	15 - 18
Affordable Energy Fund	4	-	-	**4**	**
Loss on disposal of assets	9	1	-	**10**	*
Regulatory costs	4	4	(2)	**6**	1 - 5
Gas					
DSM programs[1]	57	13	(9)	**61**	1 - 10
Deferred taxes	23	2	(4)	**21**	1 - 30
Site restoration	3	-	-	**3**	1 - 15
Loss on disposal of assets	6	3	-	**9**	*
Change in depreciation method	4	2	-	**6**	*
Regulatory costs	1	1	(1)	**1**	1 - 5
Deferred ineligible overhead	2	-	-	**2**	*
Change in depreciation rate - meters	-	1	-	**1**	*
	486	136	(56)	**566**	
Regulatory deferral credit balances					
Electric					
DSM deferral	43	6	-	**49**	*
Gas					
DSM deferral	6	2	-	**8**	*
PGVA	1	(182)	198	**17**	***
Impact of 2014 depreciation study	2	1	-	**3**	*
	52	(173)	198	**77**	
Net movement in regulatory balances		309	(254)	**55**	

[1] Included in DSM programs is the difference between actual and planned expenditures for electric and gas DSM programs.

* The amortization periods for these accounts will be determined by the PUB as part of a future regulatory proceeding.

** The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the provision (Note 27) is drawn down.

*** The PGVA is recovered or refunded in future rates.

(in millions of Canadian dollars)

	March 31, 2015	Balances arising in the year	Recovery / reversal	March 31, 2016	Remaining recovery / reversal period
					(years)
Regulatory deferral debit balances					
Electric					
DSM programs[1]	184	81	(33)	232	1 - 10
Site restoration	31	3	(3)	31	1 - 15
Change in depreciation method	29	31	-	60	*
Deferred ineligible overhead	20	20	-	40	*
Acquisition costs	11	-	(1)	10	15 - 18
Affordable Energy Fund	6	-	(2)	4	**
Loss on disposal of assets	6	3	-	9	*
Regulatory costs	1	4	(1)	4	1 - 5
Gas					
DSM programs[1]	55	10	(8)	57	1 - 10
PGVA	32	181	(213)	-	***
Deferred taxes	25	2	(4)	23	1 - 30
Site restoration	3	-	-	3	1 - 15
Loss on disposal of assets	3	3	-	6	*
Change in depreciation method	2	2	-	4	*
Regulatory costs	1	1	(1)	1	1 - 5
Deferred ineligible overhead	1	1	-	2	*
	410	342	(266)	486	
Regulatory deferral credit balances					
Electric					
DSM deferral	16	27	-	43	*
Gas					
DSM deferral	6	-	-	6	*
PGVA	-	-	1	1	***
Impact of 2014 depreciation study	1	1	-	2	*
	23	28	1	52	
Net movement in regulatory balances		314	(267)	47	

[1] Included in DSM programs is the difference between actual and planned expenditures for electric and gas DSM programs.

* The amortization periods for these accounts will be determined by the PUB as part of a future regulatory proceeding.

** The Affordable Energy Fund is amortized to the consolidated statement of income at the same rate as the provision (Note 27) is drawn down.

*** The PGVA is recovered or refunded in future rates.

The balances arising in the year consist of additions to regulatory deferral balances. The recovery/reversal consists of amounts recovered from customers through the amortization of existing regulatory balances or rate riders. The net impact of these transactions results in the net movement in regulatory deferral balances on the consolidated statement of income.

Balances arising in the year include $2 million (2016 - $2 million) for carrying costs on deferred taxes, the Affordable Energy Fund and the PGVA.

The regulatory deferral debit balances of the corporation consist of the following:

DSM program expenditures are incurred for energy conservation programs to encourage residential, commercial and industrial customers to use energy more efficiently.

Site restoration expenditures are incurred for the remediation of contaminated corporate facilities and diesel generating sites.

Change in depreciation method represents the cumulative annual difference in depreciation expense between the ASL method of depreciation as applied by Manitoba Hydro prior to its transition to IFRS and the ELG method as applied by Manitoba Hydro under IFRS.

Deferred ineligible overhead is the cumulative annual difference in overhead capitalized for financial reporting purposes under IFRS and overhead capitalized for rate setting purposes.

Acquisition costs relate to costs associated with the acquisition of Centra and Minell (July 1999) and Winnipeg Hydro (September 2002).

The Affordable Energy Fund relates to future DSM expenditures in connection with *The Winter Heating Cost Control Act*. The intent of the Affordable Energy Fund is to provide funding for projects that would not otherwise be funded by DSM programs.

Loss on disposal of assets is the net asset retirement losses for those assets retired prior to or subsequent to reaching their expected service life as determined under the ELG method of depreciation.

Regulatory costs are those incurred as a result of electric and gas regulatory hearings.

Deferred taxes are the taxes paid by Centra (July 1999) as a result of its change to non-taxable status upon acquisition by Manitoba Hydro.

Net Export Revenue

PUB Advisor Table	2016/17		
	Forecast @ Interim	Actual	Variance
Export Volumes (GWh)	7284	11291	
Export Revenues	$406	$460	
Water Rentals and Assessments	-116	-131	
Fuel and Power Purchases	-151	-132	
Net Export Revenues	**139**	**197**	**58**
Source	2016/17 Interim Att.16 revised	MH16U Appendix 3.8	

PUB Advisor Table	2017/18			
	Forecast MH16	Forecast MH16U	November Forecast	Variance to MH16U
Export Volumes	9166	10588	9423	1165
Export Revenues	454	514	-	
Water Rentals and Assessments	124	130	-	
Fuel and Power Purchases	135	124	-	
Net Export Revenues	**195**	**260**	**210**	**-50**
Source	PUB MFR 24	PUB MFR 24 Updated	Q2 2017/18 Report	

3.95% can be reduced to 3.36%. Because this is an 'interim' rate increase, the final amount of this increase is subject to the Board's determinations following a General Rate Application that Manitoba Hydro is to file in the fall of 2016. Further, the Board has decided that the rate increase be implemented as of August 1, 2016 to minimize the impact on ratepayers; the earlier increase would result in two significant increases in less than a one year time period.

The Board has concluded that Manitoba Hydro's financial situation for the 2016/17 fiscal year has improved and Manitoba Hydro does not require additional revenues from a rate increase to obtain a positive net income for 2016/17. This is especially the case when Manitoba Hydro's own projections are adjusted to implement the accounting Directives set out in Order 73/15. As such, the Board considers the public interest to be best served if the entirety of the interim rate increase flows into the Bipole III Deferral Account and can serve to reduce the expected rate shock in 2018/19 and subsequent fiscal years when Bipole III and the Keeyask Generating Station come into service.

In light of the significant revenue requirements related to the construction of new generation and transmission assets, replacement of aging infrastructure, and uncertainties associated with export markets, interest rates, domestic loads and foreign exchange rates, the Board considers it important that General Rate Applications are heard on a regular basis, and no more than two fiscal years apart. By this Order, the Board accordingly directs Manitoba Hydro to file a General Rate Application for the 2016/17 and 2017/18 years by no later than December 1, 2016. A December 2016 filing would allow for the adjustment of consumer rates for August 1, 2017. Should Manitoba Hydro wish an earlier date for rate adjustments they would need to file their Application earlier and allow approximately six months for the Board's review of a General Rate Application. The Board is not prepared to consider interim rate applications unless warranted by unforeseen or emergency situations.

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ELECTRIC OPERATIONS (MH16 20 Year Outlook)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1,517	1,569	1,561	1,552	1,551	1,552	1,559	1,567	1,577	1,584	1,593
additional*	-	88	255	397	551	717	766	817	870	923	979
BPIII Reserve Account	(96)	(119)	9	71	71	71	71	24	-	-	-
Extraprovincial	468	454	432	455	578	696	795	818	844	707	714
Other	27	30	31	31	33	33	34	34	35	35	36
	1,915	2,022	2,287	2,507	2,784	3,069	3,225	3,260	3,325	3,250	3,321
EXPENSES											
Operating and Administrative	535	518	501	511	513	524	536	548	559	571	583
Finance Expense	613	574	662	721	774	829	1,049	1,072	1,057	1,033	999
Finance Income	(18)	(16)	(20)	(27)	(27)	(32)	(38)	(17)	(21)	(22)	(17)
Depreciation and Amortization	384	396	471	515	554	597	689	714	725	739	751
Water Rentals and Assessments	131	124	112	113	114	117	127	128	131	131	131
Fuel and Power Purchased	130	135	166	146	162	149	140	138	141	128	129
Capital and Other Taxes	118	132	144	154	161	165	173	174	174	174	174
Other Expenses	60	115	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1,962	1,987	2,153	2,623	2,354	2,449	2,755	2,828	2,841	2,832	2,833
Net Income before Net Movement in Reg. Deferral	(47)	35	134	(116)	430	620	470	432	484	418	488
Net Movement in Regulatory Deferral	69	68	106	462	69	61	40	(49)	(49)	(48)	(45)
Net Income	22	102	241	346	499	681	510	383	435	369	443
Net Income Attributable to:											
Manitoba Hydro	**34**	**111**	**242**	**344**	**494**	**673**	**500**	**372**	**432**	**367**	**440**
Non-controlling Interest	(12)	(9)	(1)	2	5	8	9	11	3	2	3
* Additional Domestic Revenue											
Percent Increase	0.00%	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	7.90%	16.42%	25.62%	35.55%	46.25%	49.18%	52.16%	55.21%	58.31%	61.48%
Financial Ratios											
Equity	15%	15%	14%	15%	16%	18%	19%	20%	22%	23%	25%
EBITDA Interest Coverage	1.50	1.57	1.76	1.88	2.01	2.21	2.16	2.11	2.20	2.18	2.30
Capital Coverage	1.08	1.31	1.49	1.69	2.11	2.60	2.33	2.30	2.17	2.00	2.09

ELECTRIC OPERATIONS (MH16 20 Year Outlook)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1,599	1,608	1,623	1,639	1,667	1,698	1,730	1,762	1,796
additional*	1,034	1,093	1,158	1,225	1,304	1,389	1,478	1,571	1,669
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	708	721	733	744	745	743	739	732	654
Other	36	37	38	38	39	40	40	40	41
	3,378	3,458	3,551	3,647	3,756	3,869	3,987	4,106	4,161
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	989	973	938	913	871	835	791	752	712
Finance Income	(26)	(38)	(25)	(16)	(18)	(19)	(23)	(35)	(47)
Depreciation and Amortization	764	775	790	804	822	840	856	871	887
Water Rentals and Assessments	131	132	132	132	133	133	133	134	134
Fuel and Power Purchased	129	131	135	145	151	159	167	178	172
Capital and Other Taxes	174	175	176	177	178	179	180	181	187
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	2	2	2	2	2	2
	2,843	2,848	2,857	2,878	2,874	2,879	2,873	2,865	2,846
Net Income before Net Movement in Reg. Deferral	535	610	694	769	882	990	1,114	1,241	1,315
Net Movement in Regulatory Deferral	(43)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	491	570	659	737	851	963	1,086	1,213	1,285
Net Income Attributable to:									
Manitoba Hydro	**488**	**565**	**652**	**728**	**841**	**950**	**1,073**	**1,198**	**1,270**
Non-controlling Interest	4	5	7	9	11	12	14	15	15
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	64.71%	68.00%	71.36%	74.79%	78.28%	81.85%	85.49%	89.19%	92.98%
Financial Ratios									
Equity	27%	29%	32%	34%	38%	41%	45%	50%	55%
EBITDA Interest Coverage	2.39	2.51	2.67	2.79	3.04	3.28	3.60	3.96	4.30
Capital Coverage	2.14	2.19	2.36	2.35	2.52	2.64	2.79	2.71	2.76

ELECTRIC OPERATIONS (MH16 20 Year Outlook)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13,256	13,881	19,254	19,876	20,938	26,363	30,693	31,222	31,858	32,522	33,133
Accumulated Depreciation	(985)	(1,319)	(1,749)	(2,197)	(2,634)	(3,143)	(3,724)	(4,347)	(4,961)	(5,625)	(6,231)
Net Plant in Service	12,272	12,562	17,505	17,679	18,304	23,219	26,969	26,876	26,897	26,897	26,902
Construction in Progress	6,943	9,308	6,596	7,378	7,870	3,693	224	312	276	272	269
Current and Other Assets	1,721	1,909	2,275	2,451	2,239	1,917	1,727	1,921	2,075	1,806	1,989
Goodwill and Intangible Assets	270	485	725	869	1,271	1,225	1,180	1,135	1,092	1,049	1,007
Total Assets before Regulatory Deferral	21,206	24,264	27,101	28,377	29,684	30,054	30,099	30,244	30,340	30,024	30,168
Regulatory Deferral Balance	459	526	633	1,094	1,163	1,225	1,265	1,216	1,167	1,118	1,074
	21,665	24,790	27,734	29,471	30,847	31,279	31,364	31,461	31,507	31,143	31,242
LIABILITIES AND EQUITY											
Long-Term Debt	15,578	17,920	21,157	21,782	22,554	22,881	22,905	22,474	21,786	20,525	21,167
Current and Other Liabilities	3,415	3,905	3,303	4,067	4,209	3,666	3,249	3,417	3,708	4,226	3,232
Provisions	19	19	19	18	17	16	16	15	14	14	14
Deferred Revenue	444	460	486	515	537	546	556	566	577	588	599
BPIII Reserve Account	196	316	307	236	165	94	24	(0)	(0)	(0)	(0)
Retained Earnings	2,730	2,841	3,083	3,427	3,921	4,594	5,094	5,466	5,898	6,265	6,705
Accumulated Other Comprehensive Income	(761)	(714)	(665)	(616)	(600)	(562)	(522)	(521)	(520)	(520)	(520)
Total Liabilities and Equity before Regulatory Deferral	21,621	24,747	27,691	29,428	30,804	31,236	31,321	31,417	31,463	31,099	31,198
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44	44	44
	21,665	24,790	27,734	29,471	30,847	31,279	31,364	31,461	31,507	31,143	31,242

ELECTRIC OPERATIONS (MH16 20 Year Outlook)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ASSETS									
Plant in Service	33,741	34,487	35,147	35,978	36,754	37,549	38,293	39,095	40,163
Accumulated Depreciation	(6,924)	(7,621)	(8,329)	(9,059)	(9,806)	(10,595)	(11,384)	(12,186)	(12,993)
Net Plant in Service	26,817	26,866	26,817	26,919	26,948	26,955	26,909	26,909	27,170
Construction in Progress	351	313	348	258	232	224	264	319	115
Current and Other Assets	2,450	3,067	2,180	2,203	2,336	2,578	3,382	4,219	5,263
Goodwill and Intangible Assets	967	928	890	852	814	777	740	703	667
Total Assets before Regulatory Deferral	30,584	31,173	30,236	30,232	30,330	30,533	31,295	32,151	33,215
Regulatory Deferral Balance	1,030	990	955	923	892	864	836	807	777
	31,614	32,163	31,191	31,155	31,222	31,397	32,130	32,958	33,992
LIABILITIES AND EQUITY									
Long-Term Debt	21,120	17,702	15,049	16,670	16,080	16,264	16,318	15,907	15,791
Current and Other Liabilities	3,154	6,545	7,564	5,170	4,976	4,006	3,602	3,631	3,499
Provisions	14	14	14	14	14	14	14	14	14
Deferred Revenue	610	619	629	639	649	660	671	682	694
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7,193	7,759	8,411	9,138	9,979	10,929	12,002	13,200	14,470
Accumulated Other Comprehensive Income	(520)	(520)	(520)	(520)	(520)	(520)	(520)	(520)	(520)
Total Liabilities and Equity before Regulatory Deferral	31,571	32,120	31,147	31,111	31,178	31,354	32,087	32,914	33,948
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44
	31,614	32,163	31,191	31,155	31,222	31,397	32,130	32,958	33,992

ELECTRIC OPERATIONS (MH16 20 Year Outlook)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,007	2,131	2,268	2,425	2,701	2,986	3,141	3,224	3,313	3,237	3,308
Cash Paid to Suppliers and Employees	(876)	(917)	(881)	(880)	(903)	(908)	(923)	(937)	(954)	(952)	(964)
Interest Paid	(569)	(529)	(628)	(695)	(737)	(797)	(1,013)	(1,042)	(1,035)	(1,017)	(974)
Interest Received	7	5	12	21	17	17	9	8	14	14	10
	569	689	770	871	1,077	1,298	1,214	1,253	1,338	1,282	1,379
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2,743	3,370	3,590	1,970	1,790	790	360	(10)	(10)	(50)	790
Sinking Fund Withdrawals	146	0	0	182	303	767	173	50	330	131	224
Retirement of Long-Term Debt	(1,030)	(330)	(1,002)	(336)	(1,278)	(1,020)	(449)	(290)	(412)	(715)	(1,178)
Other	10	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1,868	3,029	2,578	1,805	804	525	95	(255)	(97)	(639)	(169)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2,609)	(3,553)	(3,015)	(2,351)	(1,742)	(1,352)	(880)	(700)	(704)	(732)	(756)
Sinking Fund Payment	(146)	(246)	(210)	(244)	(282)	(334)	(235)	(241)	(246)	(238)	(235)
Other	(68)	(51)	(55)	(44)	(128)	(91)	(84)	(83)	(83)	(80)	(79)
	(2,822)	(3,850)	(3,280)	(2,639)	(2,152)	(1,777)	(1,199)	(1,024)	(1,033)	(1,050)	(1,070)
Net Increase (Decrease) in Cash	(384)	(131)	68	37	(272)	46	111	(26)	208	(408)	140
Cash at Beginning of Year	944	559	428	496	534	262	308	419	393	601	193
Cash at End of Year	559	428	496	534	262	308	419	393	601	193	333

ELECTRIC OPERATIONS (MH16 20 Year Outlook)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,365	3,444	3,538	3,633	3,741	3,855	3,973	4,092	4,147
Cash Paid to Suppliers and Employees	(976)	(990)	(1,007)	(1,030)	(1,050)	(1,071)	(1,094)	(1,118)	(1,132)
Interest Paid	(973)	(966)	(930)	(902)	(857)	(832)	(790)	(763)	(727)
Interest Received	22	40	19	10	13	20	32	52	64
	1,438	1,529	1,621	1,712	1,847	1,972	2,121	2,263	2,352
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(20)	1,780	3,580	1,160	940	350	(90)	(30)
Sinking Fund Withdrawals	150	60	445	361	0	30	0	10	275
Retirement of Long-Term Debt	(150)	(50)	(3,450)	(4,386)	(1,982)	(1,763)	(750)	(340)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(15)	(15)	(1,230)	(450)	(828)	(800)	(404)	(424)	(25)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Sinking Fund Payment	(232)	(233)	(240)	(215)	(201)	(201)	(200)	(204)	(208)
Other	(78)	(72)	(70)	(71)	(70)	(69)	(68)	(66)	(65)
	(1,077)	(1,104)	(1,102)	(1,118)	(1,112)	(1,127)	(1,138)	(1,218)	(1,239)
Net Increase (Decrease) in Cash	346	410	(711)	144	(92)	45	579	621	1,088
Cash at Beginning of Year	333	679	1,089	378	521	429	474	1,054	1,674
Cash at End of Year	679	1,089	378	521	429	474	1,054	1,674	2,762

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
REVENUES										
Domestic Revenue										
at approved rates	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	88	256	397	546	714	758	804	857	913	972
BPIII Reserve Account	(120)	8	71	71	71	71	24	-	-	-
Extraprovincial	514	469	420	567	693	779	788	805	667	671
Other	30	31	31	33	33	34	34	35	35	36
	2 090	2 329	2 471	2 753	3 056	3 183	3 192	3 249	3 182	3 262
EXPENSES										
Operating and Administrative	518	501	511	513	524	536	548	559	571	583
Finance Expense	587	673	738	807	869	1 096	1 122	1 106	1 075	1 064
Finance Income	(17)	(21)	(28)	(35)	(36)	(39)	(17)	(17)	(14)	(17)
Depreciation and Amortization	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	132	145	154	161	166	174	175	175	175	175
Other Expenses	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 995	2 146	2 649	2 382	2 493	2 803	2 877	2 893	2 883	2 902
Net Income before Net Movement in Reg. Deferral	94	183	(178)	371	563	380	315	356	299	359
Net Movement in Regulatory Deferral	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	166	296	287	442	627	423	268	306	250	315
Net Income Attributable to:										
Manitoba Hydro	**175**	**297**	**284**	**437**	**618**	**413**	**256**	**303**	**248**	**311**
Non-controlling Interest	(8)	(1)	2	5	9	10	11	3	2	3
* Additional Domestic Revenue										
Percent Increase	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	7.90%	16.42%	25.62%	35.55%	46.25%	49.18%	52.16%	55.21%	58.31%	61.48%
Financial Ratios										
Equity	15%	15%	15%	16%	18%	18%	20%	21%	22%	23%
EBITDA Interest Coverage	1.62	1.80	1.81	1.93	2.12	2.03	1.96	2.03	2.02	2.10
Capital Coverage	1.49	1.63	1.64	2.07	2.56	2.23	2.09	1.97	1.82	1.90

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 034	1 097	1 163	1 231	1 309	1 391	1 477	1 566	1 659
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 332	3 426	3 528	3 626	3 727	3 833	3 941	4 057	4 088
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 052	1 034	1 009	987	950	925	884	834	784
Finance Income	(18)	(26)	(27)	(16)	(18)	(19)	(22)	(25)	(30)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	182	183	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 919	2 926	2 932	2 958	2 934	2 942	2 937	2 927	2 900
Net Income before Net Movement in Reg. Deferral	412	499	596	668	793	891	1 004	1 130	1 189
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	369	459	561	635	762	863	976	1 102	1 159
Net Income Attributable to:									
Manitoba Hydro	**365**	**454**	**553**	**626**	**751**	**850**	**962**	**1 086**	**1 143**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	64.71%	68.00%	71.36%	74.79%	78.28%	81.85%	85.49%	89.19%	92.98%
Financial Ratios									
Equity	25%	26%	28%	31%	34%	37%	41%	45%	49%
EBITDA Interest Coverage	2.18	2.30	2.45	2.56	2.77	2.95	3.20	3.50	3.77
Capital Coverage	1.97	2.03	2.22	2.22	2.39	2.51	2.65	2.57	2.61

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS										
Plant in Service	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 975	2 196	2 513	2 680	1 963	1 791	1 845	1 859	1 674	1 928
Goodwill and Intangible Assets	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	24 366	27 054	28 468	30 172	30 144	30 212	30 215	30 171	29 938	30 152
Regulatory Deferral Balance	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	24 899	27 701	29 579	31 354	31 390	31 501	31 457	31 363	31 082	31 250
LIABILITIES AND EQUITY										
Long-Term Debt	18 151	21 176	21 989	22 794	22 448	23 287	22 778	22 090	21 029	21 871
Current and Other Liabilities	3 643	3 043	3 812	4 352	4 138	3 015	3 169	3 450	3 971	2 977
Provisions	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	316	308	237	166	95	24	(0)	(0)	(0)	(0)
Retained Earnings	2 923	3 221	3 505	3 942	4 560	4 973	5 230	5 533	5 781	6 092
Accumulated Other Comprehensive Income	(699)	(636)	(580)	(537)	(496)	(451)	(382)	(381)	(380)	(380)
Total Liabilities and Equity before Regulatory Deferral	24 850	27 652	29 530	31 305	31 341	31 452	31 408	31 314	31 033	31 202
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49
	24 899	27 701	29 579	31 354	31 390	31 501	31 457	31 363	31 082	31 250
Net Debt	18 422	20 616	22 191	22 984	23 187	22 982	22 581	22 177	21 830	21 423
Total Equity	3 213	3 641	3 988	4 459	5 092	5 194	5 518	5 835	6 097	6 423
Equity Ratio	15%	15%	15%	16%	18%	18.43%	20%	21%	22%	23%

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 268	2 772	2 182	2 105	2 345	2 471	3 408	3 757	4 672
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 447	30 923	30 281	30 178	30 382	30 469	31 362	31 730	32 665
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	31 502	31 938	31 261	31 125	31 298	31 358	32 222	32 561	33 466
LIABILITIES AND EQUITY									
Long-Term Debt	21 803	19 406	16 353	17 593	16 962	17 577	17 060	17 079	16 943
Current and Other Liabilities	2 921	5 292	7 106	5 095	5 139	3 724	4 133	3 357	3 244
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	6 457	6 911	7 464	8 089	8 840	9 691	10 652	11 739	12 881
Accumulated Other Comprehensive Income	(380)	(380)	(380)	(380)	(380)	(380)	(380)	(380)	(380)
Total Liabilities and Equity before Regulatory Deferral	31 453	31 889	31 212	31 076	31 250	31 309	32 174	32 512	33 418
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 502	31 938	31 261	31 125	31 298	31 358	32 222	32 561	33 466
Net Debt	20 958	20 420	19 768	19 068	18 232	17 289	16 221	15 098	13 914
Total Equity	6 802	7 262	7 823	8 456	9 215	10 074	11 044	12 140	13 292
Equity Ratio	25%	26%	28%	31%	34%	37%	41%	45%	49%

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES										
Cash Receipts from Customers	2 203	2 309	2 389	2 670	2 972	3 100	3 156	3 236	3 169	3 248
Cash Paid to Suppliers and Employees	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(952)	(966)
Interest Paid	(531)	(635)	(693)	(754)	(822)	(1 045)	(1 094)	(1 083)	(1 055)	(1 040)
Interest Received	5	11	22	26	21	8	9	10	7	9
	785	843	848	1 057	1 278	1 159	1 135	1 211	1 168	1 252
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	3 478	3 390	2 160	2 190	790	1 170	(20)	(10)	150	990
Sinking Fund Withdrawals	0	0	120	318	813	182	42	333	134	228
Sinking Fund Payment	(182)	(222)	(260)	(296)	(353)	(236)	(244)	(249)	(241)	(241)
Retirement of Long-Term Debt	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	2 879	2 156	1 661	908	(127)	(14)	(517)	(342)	(677)	(206)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(85)	(60)	71	115	(326)	148	(178)	69	(324)	208
Cash at Beginning of Year	634	549	489	560	675	348	496	318	387	63
Cash at End of Year	549	489	560	675	348	496	318	387	63	271

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 318	3 412	3 514	3 612	3 713	3 818	3 927	4 043	4 074
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 087)	(1 096)
Interest Paid	(1 034)	(1 028)	(1 011)	(982)	(939)	(918)	(883)	(855)	(804)
Interest Received	15	30	34	18	14	24	35	46	53
	1 319	1 418	1 524	1 613	1 758	1 881	2 015	2 147	2 226
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	1 180	3 380	1 550	1 340	560	310	(40)
Sinking Fund Withdrawals	150	60	310	538	0	30	0	10	275
Sinking Fund Payment	(239)	(241)	(245)	(231)	(212)	(215)	(215)	(221)	(221)
Retirement of Long-Term Debt	(150)	(60)	(2 450)	(4 186)	(2 173)	(2 185)	(719)	(1 110)	(255)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(254)	(256)	(1 210)	(504)	(840)	(1 036)	(378)	(1 015)	(246)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	218	290	(551)	205	5	(83)	697	116	947
Cash at Beginning of Year	271	489	779	229	434	439	355	1 053	1 169
Cash at End of Year	489	779	229	434	439	355	1 053	1 169	2 116

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 1: 0% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES										
General Consumers										
at approved rates	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	0	123	255	393	549	590	632	680	732	785
BPIII Reserve Account	(114)	10	69	69	69	69	23	0	0	0
Extraprovincial	514	469	420	567	693	779	788	805	667	671
Other	30	31	31	33	33	34	34	35	35	36
	2 008	2 198	2 326	2 599	2 889	3 013	3 020	3 073	3 000	3 075
EXPENSES										
Operating and Administrative	518	501	511	513	524	536	548	559	571	583
Finance Expense	588	679	749	825	894	1 131	1 166	1 162	1 145	1 152
Finance Income	(17)	(21)	(28)	(35)	(34)	(37)	(14)	(15)	(13)	(16)
Depreciation and Amortization	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	132	145	154	161	165	174	175	175	175	175
Other Expenses	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 996	2 152	2 660	2 400	2 519	2 840	2 923	2 952	2 954	2 990
Net Income before Net Movement in Reg. Deferral	12	46	(333)	199	370	173	97	121	47	85
Net Movement in Regulatory Deferral	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	84	160	131	270	433	215	49	71	(2)	40
Net Income Attributable to:										
Manitoba Hydro	**92**	**161**	**129**	**265**	**425**	**206**	**38**	**68**	**(4)**	**36**
Non-controlling Interest	(8)	(1)	2	5	9	10	11	3	2	3
* Additional General Consumers Revenue										
Percent Increase	0.00%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	7.90%	16.42%	25.62%	35.55%	38.26%	41.02%	43.84%	46.72%	49.65%
Financial Ratios										
Equity	14%	14%	14%	14%	15%	15%	16%	16%	16%	16%
EBITDA Interest Coverage	1.54	1.65	1.65	1.76	1.92	1.81	1.73	1.78	1.74	1.78
Capital Coverage	1.33	1.37	1.35	1.74	2.18	1.84	1.69	1.59	1.43	1.48

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 1: 0% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
General Consumers									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	841	899	958	1 021	1 091	1 165	1 242	1 323	1 407
BPIII Reserve Account	0	0	0	0	0	0	0	0	0
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 139	3 227	3 323	3 415	3 509	3 607	3 707	3 814	3 836
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 149	1 135	1 123	1 141	1 127	1 121	1 104	1 074	1 043
Finance Income	(16)	(16)	(17)	(16)	(18)	(18)	(20)	(21)	(22)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 019	3 037	3 057	3 113	3 110	3 140	3 158	3 171	3 167
Net Income before Net Movement in Reg. Deferral	120	190	266	303	398	467	548	643	669
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	76	150	231	270	367	439	520	614	639
Net Income Attributable to:									
Manitoba Hydro	**72**	**144**	**224**	**260**	**356**	**426**	**506**	**599**	**623**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	52.65%	55.70%	58.81%	61.99%	65.23%	68.53%	71.90%	75.34%	78.85%
Financial Ratios									
Equity	17%	17%	18%	19%	20%	22%	24%	26%	29%
EBITDA Interest Coverage	1.83	1.91	2.00	2.03	2.15	2.23	2.34	2.48	2.56
Capital Coverage	1.54	1.59	1.74	1.72	1.86	1.94	2.05	1.99	2.00

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 2: 1.6% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
REVENUES										
General Consumers										
at approved rates	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	18	150	283	424	582	624	667	716	768	823
BPIII Reserve Account	(115)	10	70	70	70	70	23	0	0	0
Extraprovincial	514	469	420	567	693	779	788	805	667	671
Other	30	31	31	33	33	34	34	35	35	36
	2 025	2 225	2 356	2 630	2 922	3 048	3 055	3 108	3 037	3 112
EXPENSES										
Operating and Administrative	518	501	511	513	524	536	548	559	571	583
Finance Expense	588	678	748	822	887	1 128	1 161	1 146	1 131	1 133
Finance Income	(17)	(21)	(29)	(35)	(33)	(40)	(16)	(13)	(14)	(16)
Depreciation and Amortization	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	132	145	154	161	165	174	175	175	175	175
Other Expenses	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 996	2 151	2 658	2 397	2 513	2 835	2 916	2 938	2 939	2 971
Net Income before Net Movement in Reg. Deferral	29	74	(302)	233	410	213	139	170	98	141
Net Movement in Regulatory Deferral	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	101	187	162	305	473	256	91	121	49	96
Net Income Attributable to:										
Manitoba Hydro	**109**	**189**	**160**	**299**	**465**	**246**	**80**	**118**	**47**	**93**
Non-controlling Interest	(8)	(1)	2	5	9	10	11	3	2	3
* Additional General Consumers Revenue										
Percent Increase	1.60%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	1.60%	9.63%	18.29%	27.63%	37.71%	40.47%	43.28%	46.14%	49.07%	52.05%
Financial Ratios										
Equity	15%	14%	14%	15%	16%	16%	16%	17%	17%	18%
EBITDA Interest Coverage	1.55	1.68	1.68	1.80	1.96	1.85	1.77	1.83	1.79	1.84
Capital Coverage	1.36	1.43	1.40	1.81	2.25	1.92	1.76	1.67	1.51	1.57

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 2: 1.6% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
General Consumers									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	880	939	1 000	1 063	1 135	1 211	1 290	1 372	1 458
BPIII Reserve Account	0	0	0	0	0	0	0	0	0
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 178	3 267	3 365	3 458	3 553	3 652	3 754	3 863	3 887
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 129	1 114	1 099	1 110	1 089	1 083	1 061	1 027	990
Finance Income	(16)	(17)	(19)	(16)	(17)	(19)	(22)	(22)	(23)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	177	178	179	180	181	182	183	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 998	3 015	3 032	3 081	3 075	3 101	3 115	3 123	3 112
Net Income before Net Movement in Reg. Deferral	180	253	333	377	478	552	639	740	775
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	136	213	298	344	447	524	611	712	745
Net Income Attributable to:									
Manitoba Hydro	**132**	**207**	**291**	**334**	**436**	**511**	**597**	**696**	**729**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	55.09%	58.19%	61.35%	64.58%	67.87%	71.23%	74.66%	78.15%	81.71%
Financial Ratios									
Equity	18%	19%	20%	21%	23%	25%	27%	30%	33%
EBITDA Interest Coverage	1.89	1.98	2.09	2.12	2.26	2.35	2.48	2.64	2.75
Capital Coverage	1.62	1.68	1.84	1.82	1.97	2.06	2.17	2.11	2.13

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 3: 3.36% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES										
General Consumers										
at approved rates	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	37	179	315	458	619	661	705	755	809	865
BPIII Reserve Account	(116)	10	70	70	70	70	23	0	0	0
Extraprovincial	514	469	420	567	693	779	788	805	667	671
Other	30	31	31	33	33	34	34	35	35	36
	2 043	2 254	2 388	2 665	2 960	3 086	3 093	3 148	3 078	3 154
EXPENSES										
Operating and Administrative	518	501	511	513	524	536	548	559	571	583
Finance Expense	587	676	744	817	882	1 119	1 150	1 135	1 113	1 112
Finance Income	(17)	(21)	(28)	(35)	(34)	(40)	(17)	(14)	(13)	(16)
Depreciation and Amortization	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	132	145	154	161	165	174	175	175	175	175
Other Expenses	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 995	2 150	2 655	2 392	2 507	2 825	2 905	2 925	2 922	2 951
Net Income before Net Movement in Reg. Deferral	47	104	(267)	273	452	260	188	223	156	203
Net Movement in Regulatory Deferral	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	119	218	198	344	516	303	141	173	107	158
Net Income Attributable to:										
Manitoba Hydro	**128**	**219**	**195**	**338**	**507**	**293**	**129**	**170**	**105**	**155**
Non-controlling Interest	(8)	(1)	2	5	9	10	11	3	2	3
* Additional General Consumers Revenue										
Percent Increase	3.36%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	3.36%	11.53%	20.34%	29.84%	40.10%	42.90%	45.76%	48.68%	51.65%	54.68%
Financial Ratios										
Equity	15%	14%	14%	15%	17%	17%	17%	18%	19%	19%
EBITDA Interest Coverage	1.57	1.72	1.72	1.83	2.01	1.90	1.82	1.88	1.86	1.91
Capital Coverage	1.40	1.48	1.47	1.88	2.34	2.00	1.85	1.75	1.61	1.66

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 3: 3.36% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
General Consumers									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	923	983	1 045	1 110	1 184	1 261	1 342	1 426	1 514
BPIII Reserve Account	0	0	0	0	0	0	0	0	0
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 221	3 312	3 410	3 505	3 602	3 703	3 806	3 917	3 943
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 108	1 093	1 073	1 077	1 049	1 035	1 012	973	934
Finance Income	(17)	(21)	(21)	(17)	(17)	(17)	(23)	(23)	(26)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 976	2 990	3 003	3 047	3 034	3 055	3 064	3 067	3 053
Net Income before Net Movement in Reg. Deferral	245	322	407	458	568	648	742	850	890
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	202	281	373	425	537	620	714	821	860
Net Income Attributable to:									
Manitoba Hydro	**197**	**276**	**365**	**416**	**526**	**608**	**700**	**806**	**844**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	57.78%	60.93%	64.15%	67.43%	70.78%	74.20%	77.68%	81.23%	84.86%
Financial Ratios									
Equity	20%	21%	22%	24%	26%	28%	31%	34%	37%
EBITDA Interest Coverage	1.97	2.06	2.18	2.23	2.39	2.51	2.66	2.85	2.99
Capital Coverage	1.72	1.78	1.94	1.93	2.09	2.18	2.31	2.24	2.26

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 4: 3.95% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES										
General Consumers										
at approved rates	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	44	189	326	470	631	674	718	769	822	879
BPIII Reserve Account	(117)	9	70	70	70	70	23	0	0	0
Extraprovincial	514	469	420	567	693	779	788	805	667	671
Other	30	31	31	33	33	34	34	35	35	36
	2 049	2 264	2 399	2 676	2 972	3 098	3 106	3 161	3 091	3 168
EXPENSES										
Operating and Administrative	518	501	511	513	524	536	548	559	571	583
Finance Expense	587	676	744	815	878	1 114	1 141	1 133	1 109	1 112
Finance Income	(17)	(21)	(29)	(34)	(33)	(38)	(14)	(16)	(13)	(19)
Depreciation and Amortization	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	132	145	154	161	165	174	175	175	175	175
Other Expenses	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 995	2 149	2 654	2 390	2 504	2 822	2 899	2 922	2 918	2 948
Net Income before Net Movement in Reg. Deferral	54	114	(256)	286	468	276	207	239	173	220
Net Movement in Regulatory Deferral	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	125	228	209	357	532	319	159	190	125	175
Net Income Attributable to:										
Manitoba Hydro	**134**	**229**	**206**	**352**	**523**	**309**	**148**	**186**	**122**	**172**
Non-controlling Interest	(8)	(1)	2	5	9	10	11	3	2	3
* Additional General Consumers Revenue										
Percent Increase	3.95%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	3.95%	12.16%	21.02%	30.58%	40.90%	43.72%	46.59%	49.52%	52.51%	55.56%
Financial Ratios										
Equity	15%	15%	15%	15%	17%	17%	18%	18%	19%	20%
EBITDA Interest Coverage	1.58	1.73	1.73	1.85	2.02	1.92	1.84	1.90	1.87	1.93
Capital Coverage	1.41	1.50	1.49	1.90	2.37	2.04	1.89	1.78	1.63	1.69

ELECTRIC OPERATIONS (MH16 UPDATE)
PROJECTED OPERATING STATEMENT
PUB Scenario (i) - 4: 3.95% in 2017/18, MH16 Update Proposed Rates 2018/19 to 2035/36
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
REVENUES									
General Consumers									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	938	998	1 061	1 126	1 200	1 278	1 360	1 445	1 533
BPIII Reserve Account	0	0	0	0	0	0	0	0	0
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 235	3 326	3 426	3 521	3 618	3 720	3 824	3 935	3 962
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 102	1 083	1 064	1 067	1 038	1 022	994	955	912
Finance Income	(17)	(20)	(21)	(17)	(18)	(18)	(21)	(23)	(26)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	182	183	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 970	2 981	2 994	3 037	3 022	3 040	3 048	3 049	3 033
Net Income before Net Movement in Reg. Deferral	265	345	432	484	595	679	776	886	929
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	221	305	397	451	565	651	748	858	899
Net Income Attributable to:									
Manitoba Hydro	**217**	**299**	**389**	**442**	**553**	**639**	**733**	**842**	**883**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional General Consumers Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	58.68%	61.85%	65.09%	68.39%	71.76%	75.19%	78.69%	82.27%	85.91%
Financial Ratios									
Equity	21%	22%	23%	25%	27%	29%	32%	35%	39%
EBITDA Interest Coverage	1.99	2.09	2.22	2.27	2.43	2.56	2.72	2.92	3.08
Capital Coverage	1.75	1.81	1.98	1.97	2.13	2.23	2.35	2.28	2.31

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	176
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	0	0	0	0	0	0	0	0	0	0
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	909	850	800	742	675	618
Finance Income	(29)	(46)	(57)	(18)	(19)	(19)	(26)	(32)	(50)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	183	184	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 894	2 892	2 888	2 878	2 833	2 818	2 792	2 762	2 714
Net Income before Net Movement in Reg. Deferral	698	801	915	1 032	1 189	1 320	1 465	1 623	1 714
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	654	761	880	999	1 158	1 292	1 437	1 595	1 684
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	650	755	873	989	1 147	1 280	1 423	1 579	1 668
Non-recurring Gain	0	0	0	0	0	0	0	0	0
Manitoba Hydro	**650**	**755**	**873**	**989**	**1 147**	**1 280**	**1 423**	**1 579**	**1 668**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	27%	30%	33%	37%	41%	46%	52%	57%	64%
EBITDA Interest Coverage	2.48	2.65	2.85	3.09	3.45	3.79	4.25	4.86	5.52
Capital Coverage	2.39	2.47	2.68	2.71	2.93	3.08	3.25	3.16	3.23

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity	2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 824	3 630	2 359	2 041	2 278	2 625	3 629	4 069	5 509
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	31 004	31 781	30 458	30 114	30 315	30 623	31 584	32 041	33 501
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 751	14 977	14 280	13 859	13 743
Current and Other Liabilities	2 920	5 271	7 325	5 089	5 140	3 906	4 103	3 363	3 230
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7 214	7 969	8 842	9 831	10 977	12 257	13 680	15 259	16 927
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	32 010	32 747	31 389	31 012	31 183	31 463	32 395	32 824	34 254
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
Net Debt	20 197	19 357	18 386	17 327	16 094	14 725	13 200	11 587	9 877
Total Equity	7 564	8 325	9 206	10 203	11 357	12 645	14 077	15 665	17 343
Equity Ratio	27%	30%	33%	37%	41%	46%	52%	57%	64%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 087)	(1 097)
Interest Paid	(1 019)	(1 014)	(997)	(908)	(837)	(795)	(742)	(696)	(632)
Interest Received	26	51	63	20	15	22	36	49	67
	1 604	1 720	1 843	1 972	2 155	2 307	2 473	2 637	2 752
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 150	1 140	360	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(195)	(193)	(188)	(189)	(184)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 223)	(1 219)	(704)	(1 383)	(209)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	505	594	(1 229)	(41)	19	160	829	238	1 510
Cash at Beginning of Year	541	1 047	1 640	411	370	389	549	1 378	1 616
Cash at End of Year	1 047	1 640	411	370	389	549	1 378	1 616	3 126

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generation from high water flows contributed $62 million to 2015/16 net income and $87 million to 2016/17 net income as shown in **Figure 15** below. Under the MH16 Update, high water and above average generation will contribute approximately $91 million to 2017/18 earnings and $41 million to 2018/19 earnings, which reflects an increase in net extraprovincial revenues of $65 million and $56 million from MH16 even after taking into account the impact of softer expected export prices. **Figure 15** also shows that under average generation and no proposed rate increases, MH16 Updated earnings would be essentially break-even in 2017/18 and 2018/19, and 2015/16 and 2016/17 would have resulted in net losses indicating that Manitoba Hydro's domestic revenues at approved rates and export revenues are not sufficient to fund operations or make reasonable contributions to retained earnings.

Figure 15. Net Income under Average Generation and No Proposed Rate Increases

	(Millions of Dollars)			
	Actual	MH16	MH16 Update	
	2015/16	2016/17	2017/18	2018/19
Net Income	37	34	175	297
Revenue Attributable to Above Average Water	(62)	(87)	(91)	(41)
Additional Revenue from Rate Increases	-	-	(88)	(256)
Adjusted Net Income/(Loss)	**(25)**	**(53)**	**(4)**	**0**

Figure 6 above demonstrates how quickly water conditions can transition from wet to dry. The 2003/04 drought was the quickest and largest transition on record. It can be seen that from average generation in 2001/02, generation dropped approximately 60% by 2003/04. Water conditions then rapidly reversed and generation increased to approximately 20% above average by 2005/06. **Figure 6** also shows that water conditions similar to that of the 2003/04 drought are not out of realm of possibility for 2018/19 (bottom of the red box representing generation at the lowest flow on record), reducing net income in 2018/19 by a further $194 million from a breakeven adjusted net income.

The following **Figure 16** updates the scenarios requested by the PUB in its letter of June 9, 2017 and filed as Attachments 1 and 2 of Manitoba Hydro's Interim Written Submission (the projected Financial Statements underlying each scenario can be found in Appendix 3.7).

Relative to the assumptions in MH16, long-term export prices continue to see further flattened growth, with natural gas price declines along with the increased buildout of renewables putting downward pressure on price appreciation. On-peak prices are down approximately 7% compared to the forecast underpinning MH16 and down approximately 17% from the 2016 EEPF. Off-peak prices have seen a larger decline than on-peak prices, down 10% compared to the forecast underpinning MH16 and down 20% from the 2016 EEPF, showing the larger effect that wind generation has in pushing the prices down overnight. The 2016 EEPF was itself an approximately 15% decline in export prices in comparison to those assumed in MH15.

Average unit revenues and costs have been revised in PUB MFR 24 and the 2017 third-party and consensus forecast prices have been provided in revised PUB MFR 79.

2.5 Water Conditions

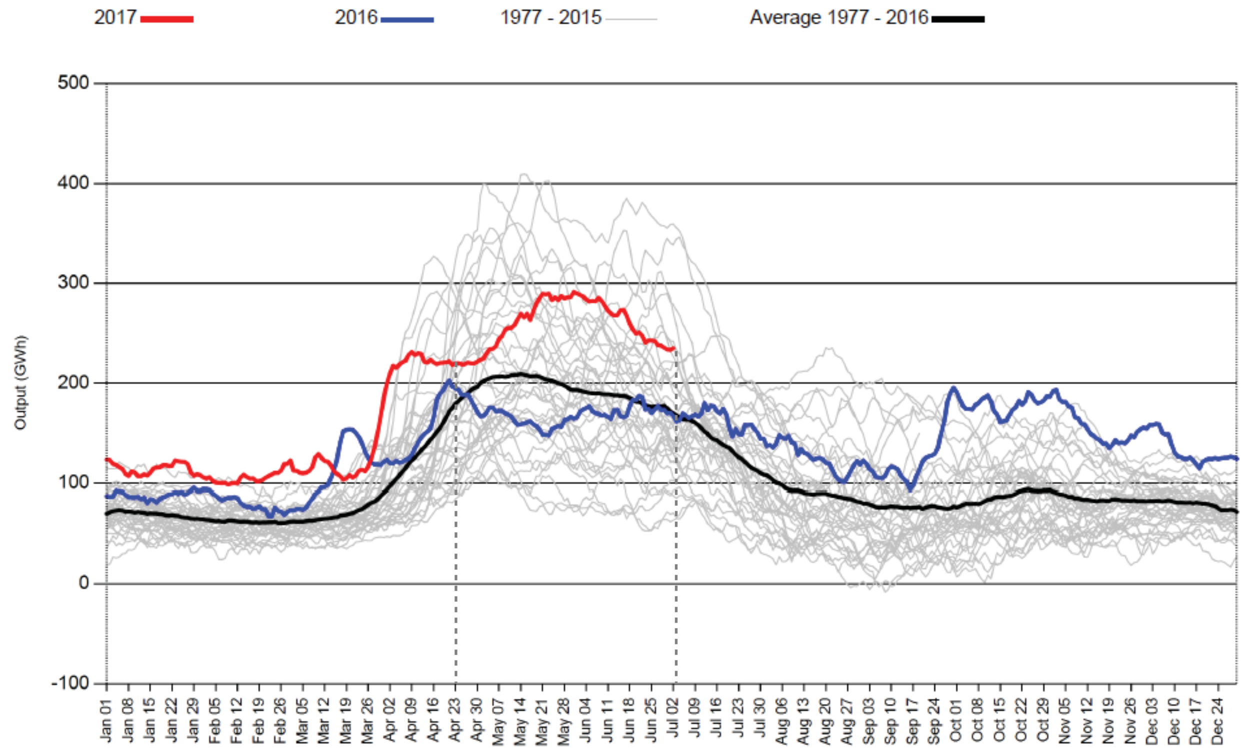
Precipitation

System precipitation since March 1, 2017 has been normal to above normal for all basins with the exception of the Winnipeg River Basin being below normal. Runoff volumes in the Churchill and Saskatchewan River basins were well above average to record highs due to significant accumulated winter snowpack. The precipitation report for the past 60 days has been below average for all basins.

Inflows

Figure 4 (which is an update to Figure 7.13 from Tab 7) below shows historical daily inflows beginning in 1977, with inflows for 2016 and 2017 and the average shown as highlighted. Despite the below average precipitation in the past two months, hydraulic energy from inflow is still above average as the significant runoff volumes in the north slowly recede.

Figure 4. Daily Hydraulic Energy from Inflow

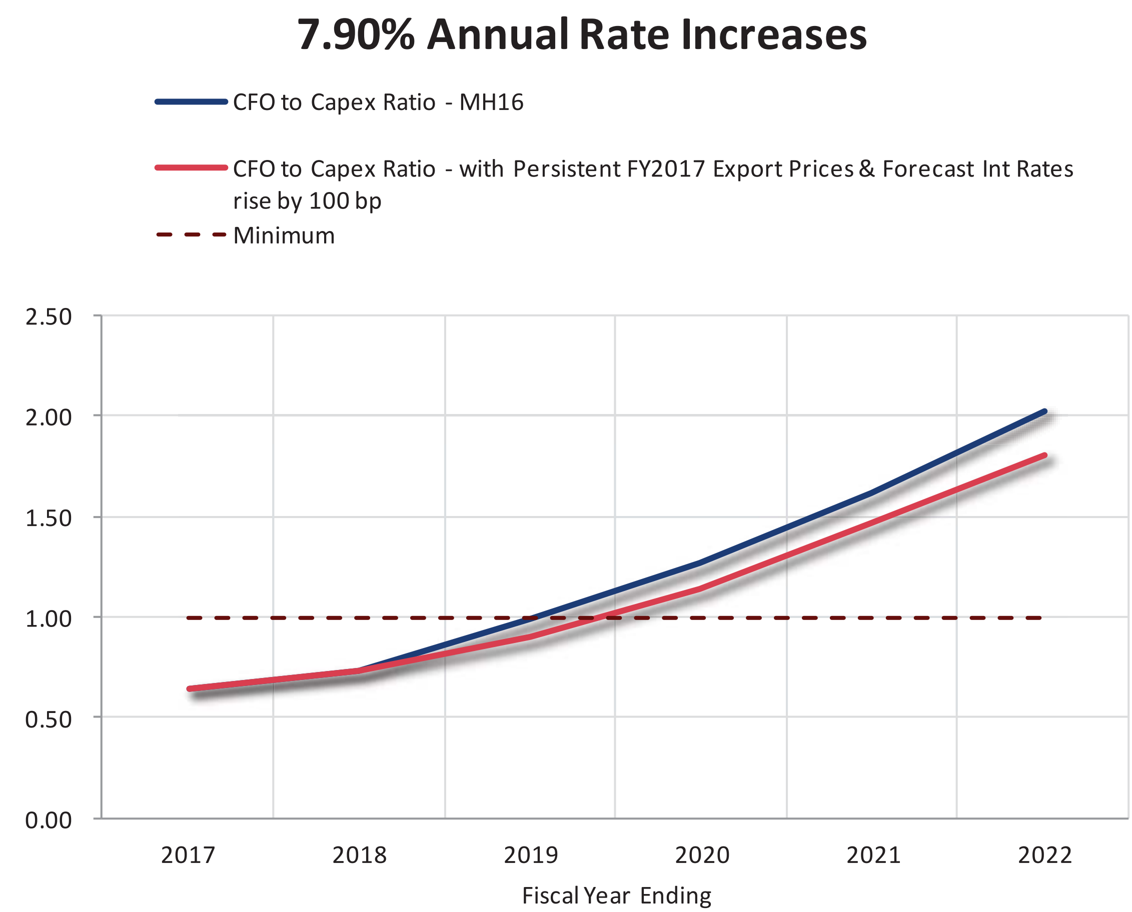


Energy in Reservoir Storage

Figure 5 (which is an update to Figure 7.14 from Tab 7) shows historical daily energy in reservoir storage beginning in 1977, with values for 2016 and 2017 and the average shown as highlighted. This indicator is for the major reservoirs in Manitoba Hydro's watersheds including reservoirs regulated by other agencies whose operations affect the flows at Manitoba Hydro's generating stations.

Due to the record high carry over storage from 2016/17 and significant runoff volumes through the spring, current system energy in reservoir storage is third highest on record. Manitoba Hydro continues to spill a significant portion of this water. Spill conditions with maximum Lake Winnipeg outflow operations are expected to continue into August 2017.

Figure 2.20 Cash Flow from Operations to CapEx Ratio with 7.90% Annual Rate Increases



In addition, 2021/22-2023/24 will see the first unit in-service and final commissioning of the Keeyask Generating Station. As shown in **Figure 2.21** below, Keeyask is anticipated to be cash flow negative and contribute a net loss to Manitoba Hydro until at least the mid to late 2030s when the bulk of its capacity shifts to satisfying domestic needs.

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Manitoba Hydro
360 Portage Ave (22) • Winnipeg, Manitoba Canada • R3C 0G8
Telephone / N° de téléphone: (204) 360-3946 • Fax / N° de télécopieur: (204) 360-6147 • pjramage@hydro.mb.ca

November 16, 2017

Darren Christle
Executive Director and Secretary
Public Utilities Board of Manitoba
400 – 330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO QUARTERLY REPORT FOR THE SIX MONTHS ENDED SEPTEMBER 30, 2017

On November 13, 2017, Manitoba Hydro announced its consolidated financial results for the six months ended September 30, 2017.

As part of the response to PUB MFR 13 filed on May 12, 2017, Manitoba Hydro provided copies of its financial statements up to and including the third quarter of the 2016/17 fiscal year (9 month period ended December 31, 2016). Enclosed with this letter, Manitoba Hydro is providing an update to PUB MFR 13 and its quarterly reports for the first and second quarters of fiscal year 2017/18. Manitoba Hydro is also enclosing an update to Appendix 7.4 (Directive 5 of Order 43/13) to provide actual monthly hydraulic generation, water conditions and extra-provincial energy exchange data for the month of October 2017.

As noted in PUB MFR 13 (Updated), Manitoba Hydro's forecast consolidated net income for the full 2017/18 fiscal year has decreased to $40 million. The Corporation can advise the PUB that the 2017/18 forecast for the electric segment is approximately $30 million assuming normal system inflows and average winter weather conditions.

This compares to a forecast of $93 million for 2017/18 under MH16 Update with Interim (filed as Appendix 3.8). The principal cause of the 68% reduction in Manitoba Hydro's profit outlook is a precipitous decline in net export revenues. Overall, net export revenues are now estimated to be $210 million in the 2017/18 fiscal year which represents a $58 million or 22% reduction from the assumptions in MH16 Update with Interim.

System inflows since late April were considerably below historical average which has dramatically reduced reservoir levels from near record highs to just above mean. Manitoba Hydro forecasts average water flow conditions for the remainder of 2017/18. Nonetheless generation volume is now expected to be lower than forecast in MH16 Update with Interim leading to an anticipated 11% decline in export volumes (in GWh).

Of further note, PUB MFR 13 (Updated) indicates that opportunity and contract market export prices have fallen significantly short of anticipated levels and have demonstrated minimal appreciation from prior year. As of September 30, 2017, on-peak opportunity prices were 22% below the target in MH16 Update with Interim while off peak prices were 6% below target. This represents a further deterioration compared to the quarter ended June 30, 2017 where on-peak and off-peak prices were 16% and 4% below target.

Manitoba Hydro has not updated its integrated financial forecast; however, it can advise that net export revenues for next fiscal year, 2018/19, are now expected to be $198 million which represents a $12 million decline from the updated forecast for this fiscal year and a $20 million (or 9.3%) reduction from levels assumed in MH16 Update with Interim. Generation volume is still anticipated to be above average in 2018/19 as Manitoba Hydro forecasts beginning the year with higher than average reservoir levels.

MH16 Update was prepared following very high spring run-off and filed as Appendix 3.6 on July 11, 2017. The significant deterioration in outlook since that time is an example of the potential volatility in Manitoba Hydro's short and long-term results due to water levels and export market conditions.

Should you have any questions with respect to the forgoing, please do not hesitate to contact the writer at 204-360-3946 or Greg Barnlund at 204-360-5243.

Yours truly,

MANITOBA HYDRO LEGAL SERVICES DIVISION
Patti Ramage
Barrister & Solicitor

cc: All Approved Interveners
Odette Fernandes, Manitoba Hydro
Bob Peters, Board Counsel
Dayna Steinfeld, Board Counsel

Chart (b) - Energy in Storage

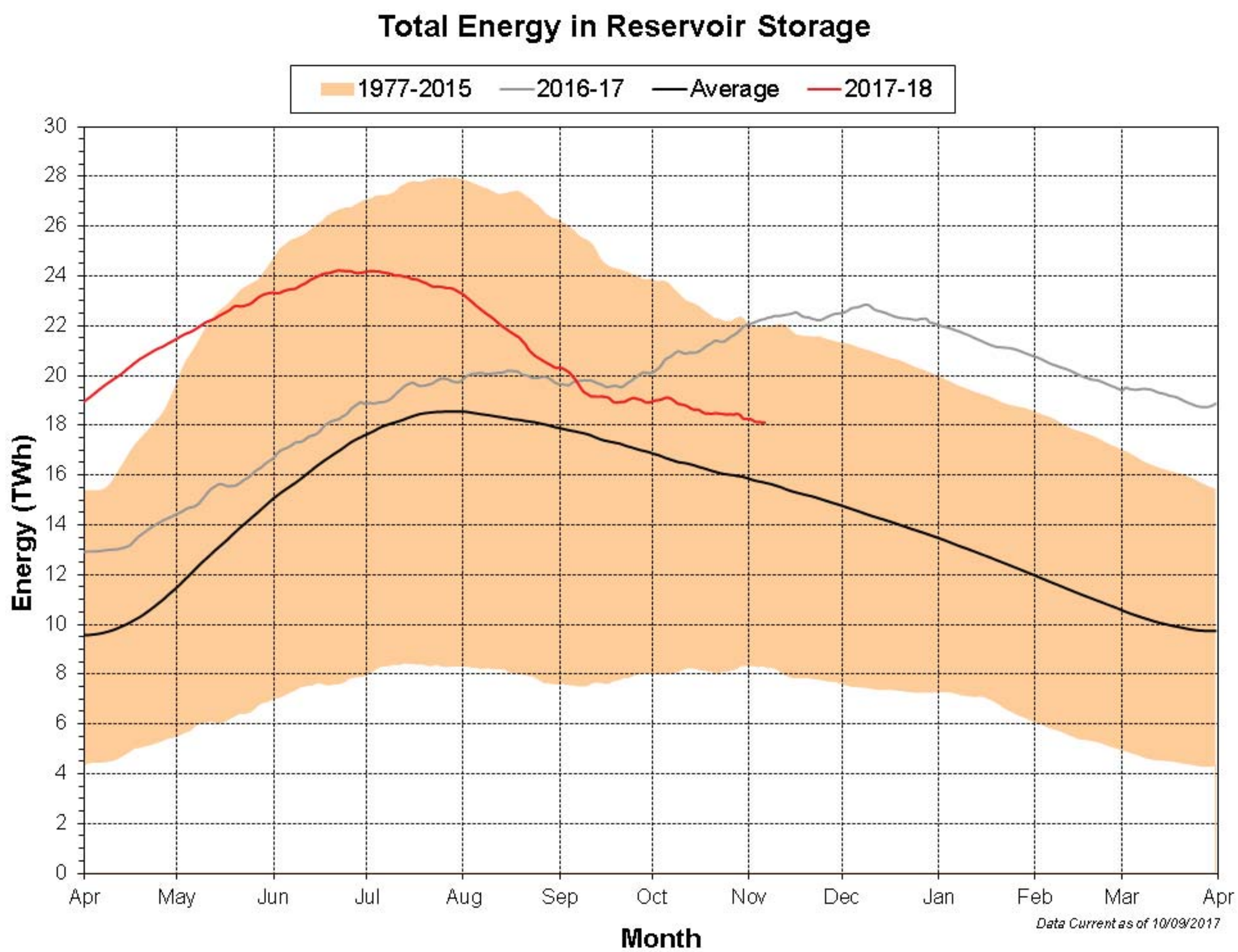

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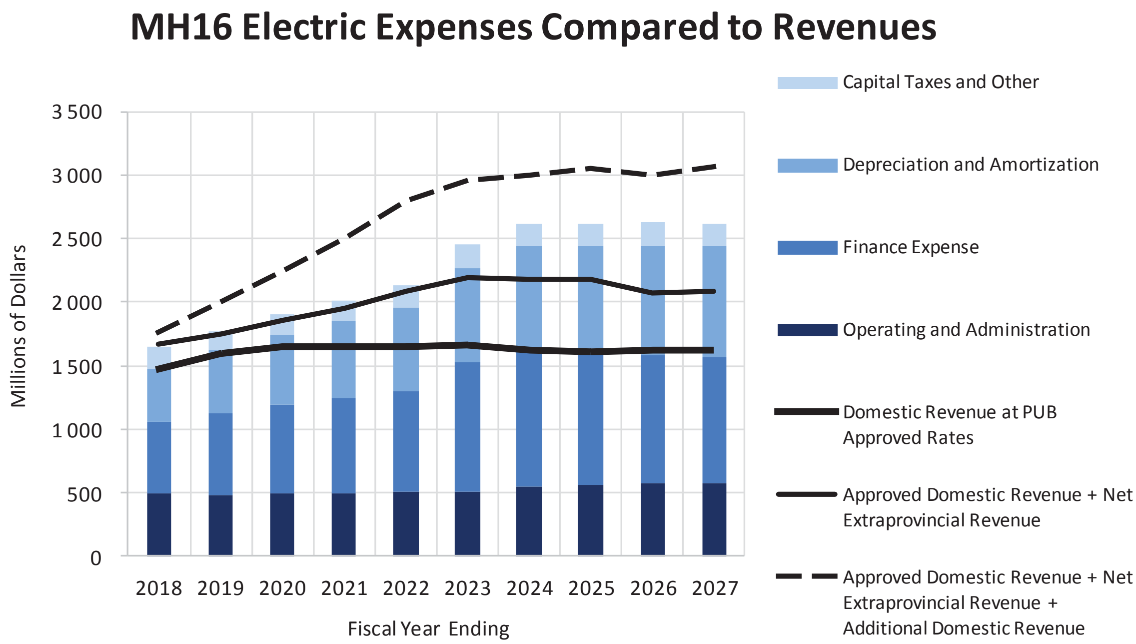
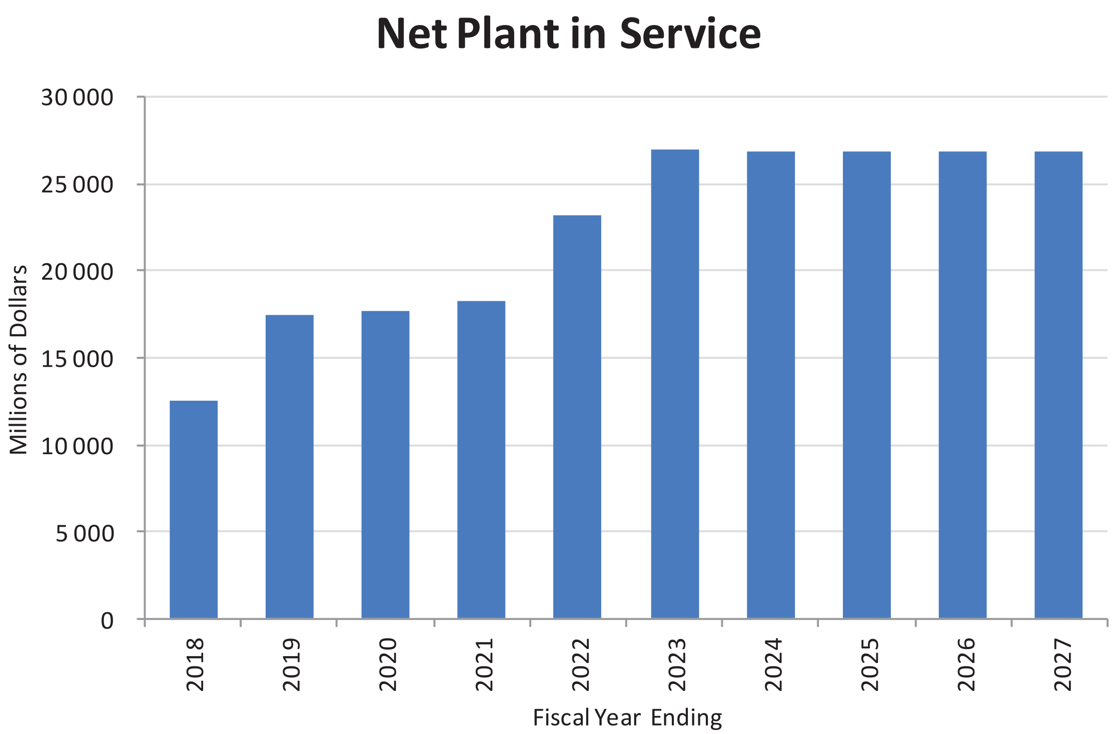
Figure 2.6 MH16 Electric Expenses Compared to Revenues



While **Figure 2.6** shows the forecast growth in domestic and export revenues against expenses, it must be recognized that Manitoba Hydro's net plant in service increases 115% from approximately $12 billion today to almost $27 billion in 2022/23, as shown in **Figure 2.7.**

Figure 2.7 MH16 Net Plant in Service



Even with cost reductions and the proposed rate increases, debt will peak at $23 billion in 2021/22. The forecast level of net income and positive cash flow Manitoba Hydro should generate should reflect the growing size of its balance sheet and the risks associated with the significant levels of debt required to fund this investment.

Levels of net income and cash flow appropriate for a Corporation with $12 billion of assets in service must be scaled up significantly to reasonably address the risks associated with operating $27 billion worth of assets by 2027. Increased levels of net income will consequently result in improvements to the levels of retained earnings in the 10 years of the forecast.

2.1.8 Sensitivity of Manitoba Hydro’s Current Financial Forecast (MH16)

As shown in **Figures 2.8 and 2.9** below, even with the proposed and indicative rate increases, Manitoba Hydro’s net income would decline by approximately 40% and would only modestly improve its equity capitalization over the 10-year period, should interest rates rise by 100 basis points in 2017/18 and export prices remain low.

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Manitoba Hydro
2015 General Rate Application

OVERVIEW & REASONS FOR THE APPLICATION

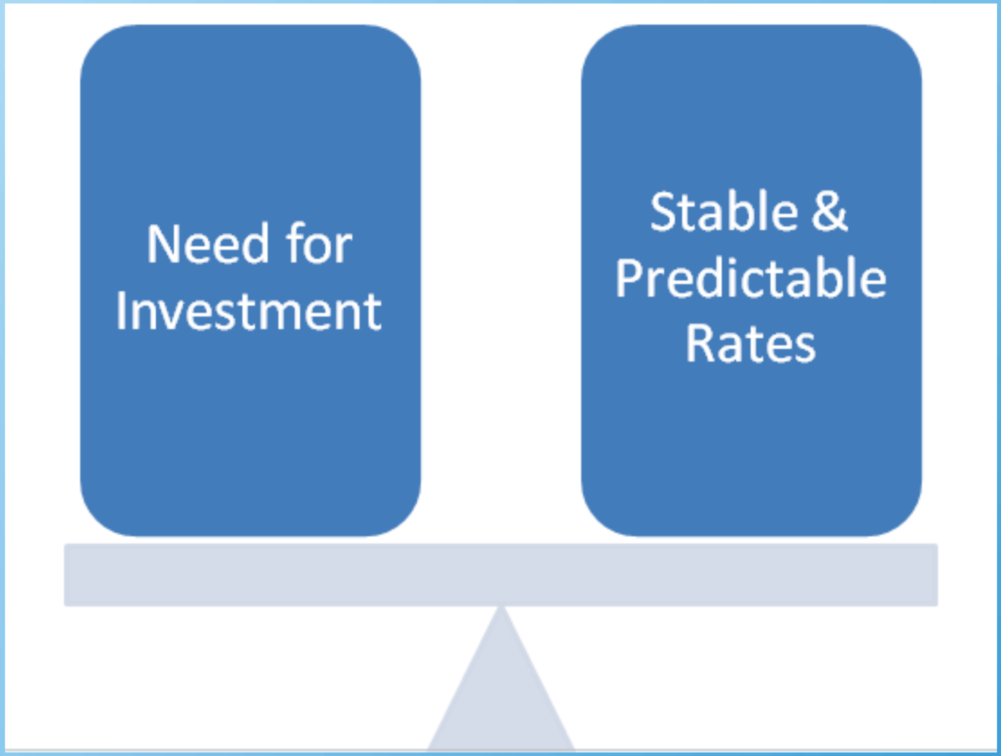
Darren Rainkie
Vice-President, Finance & Regulatory
Manitoba Hydro

Why Rate Increases are Needed

- Manitoba Hydro is entering a period of extensive capital investment to meet growing energy requirements, replace aging utility assets and address increased capacity constraints on our system.
- Manitoba Hydro's projected costs and revenue requirements are significantly increasing due to the investment in assets – which is the key factor driving the need for rate increases.
- The investments in capital will place pressure on Manitoba Hydro's Financial Strength.
- The proposed rate increases are needed to:
  - Maintain a reliable energy supply to Manitobans; and,
  - Promote long term rate stability for customers by maintaining Net Income & Financial Ratios at acceptable levels.

Manitoba Hydro

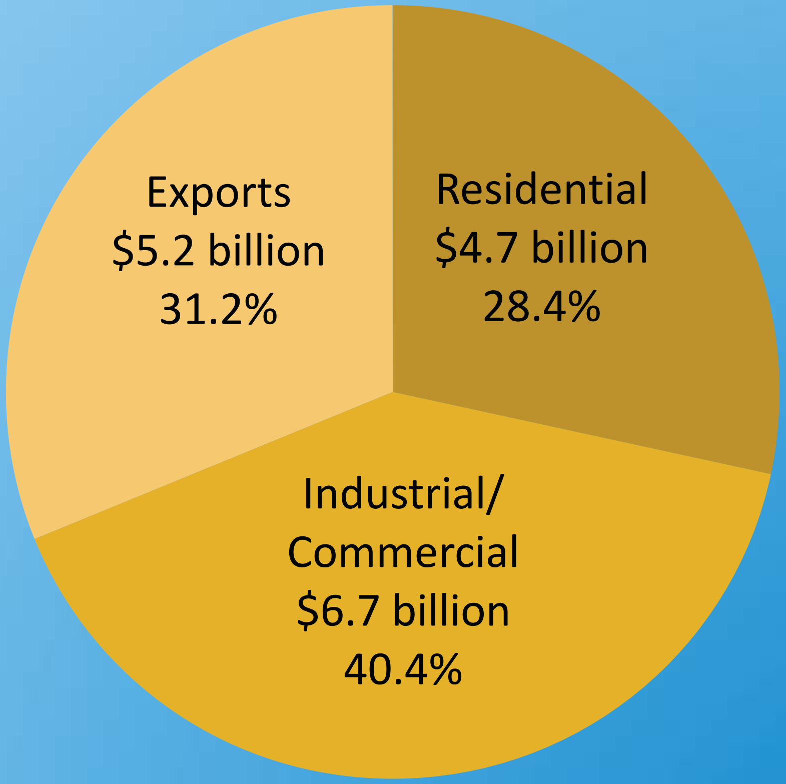
Balancing the Need for Investment with Stable & Predictable Rates



- The required capital investment means that rates will need to increase over the next decade to fund these investments.
- Manitoba Hydro believes that the proposed rate increases carefully balance the need for investment and providing stable, predictable rates for our customers.

Share of Total Electric Revenues 2005-2014

- Surplus electricity exported to three wholesale markets in Midwest US and Canada
- Last decade – export sales contributed $5.2 billion or 31% of total revenues
- Export revenues are used to keep rates low for Manitobans



Manitoba Hydro

Consolidated Balance Sheet

(Condensed $ millions)

	As at December 31	As at March 31						
	2014	2014	2013	2012	2011	2010	2009	2008
Property, Plant and Equipment (net)	11 755	10 684	10 541	8 647	8 215	8 076	7 944	7 697
Construction in Progress	3 064	2 943	1 967	3 150	2 739	2 052	1 438	1 238
	14 819	13 627	12 508	11 797	10 954	10 128	9 382	8 935
Current and Other Assets	2 129	1 901	1 682	1 622	1 646	1 487	1 499	2113
Total Assets	16 948	15 528	14 190	13 419	12 600	11 615	10 881	11 048
Long-Term Debt (Net)	11 641	10 349	8 977	8 729	8 335	7 406	7 002	6 500
Current and Other Liabilities	2 015	1 913	1 937	1 495	1 127	1 328	1 637	2097
Retained Earnings	2 758	2 716	2 542	2 450	2 389	2 239	2 076	1822
Other Equity	534	550	734	745	749	642	166	629
Total Liabilities & Equity	16 948	15 528	14 190	13 419	12 600	11 615	10 881	11 048
Debt/Equity Ratio*	78:22	76:24	75:25	74:26	73:27	73:27	77:23	73:27

*The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Debt-to-equity ratio represents debt (long-term debt plus notes payable minus sinking funds and temporary investments) divided by debt plus equity (retained earnings plus accumulated other comprehensive income plus contributions in aid of construction plus non-controlling interest).

Manitoba Hydro

Consolidated Cash Flow Statement

(Condensed $ millions)

	For the nine months ended December 31	For the year ended March 31						
	2014	2014	2013	2012	2011	2010	2009	2008
Cash provided by Operating Activities	447	690	589	567	595	589	688	633
Cash provided by Financing Activities	1 150	1101	635	725	674	1 124	424	487
Cash used for Investing Activities	(1 360)	(1 681)	(1 242)	(1 312)	(1 373)	(1 698)	(1 086)	(988)
Capital Coverage Ratio*	1.01	1.35	1.25	1.13	1.25	1.34	1.77	1.62

*The capital coverage ratio measures the ability of current period internally generated funds to finance capital expenditures excluding major new generation and related transmission. Capital coverage ratio represents internally generated funds divided by sustaining capital expenditures.

Manitoba Hydro

General Rate Application Overview

Manitoba Hydro

2015 General Rate Application

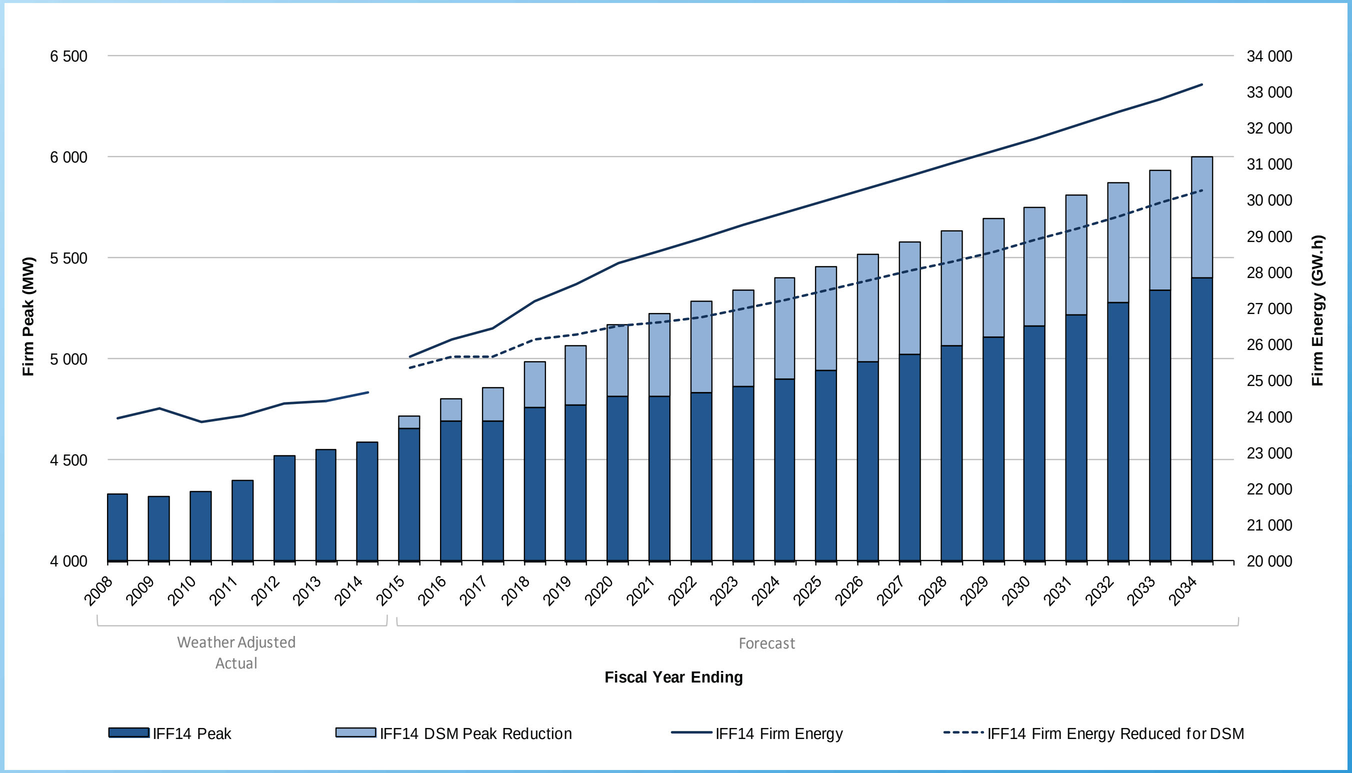
- Final approval of 2.75% interim rate increase effective May 1, 2014
- Approval of a 3.95% rate increase for 2015/16
  - $3.20 increase in monthly bill of residential customer without electric space heat
  - $6.11 increase in monthly bill of residential customer with electric space heat
- Final approval of LED Rates effective August 1, 2014
- Changes to SEP and CRP Terms & Conditions
- Final approval of Interim Orders on SEP, CRP and Diesel
- Approval to rescind DSM deferral account

Manitoba Hydro

Manitoba Hydro's
Capital Investment Drivers &
Borrowing Requirements

Manitoba Hydro is Entering a Period of Extensive Capital Investment

Forecast Load Growth Before and After Impact of DSM

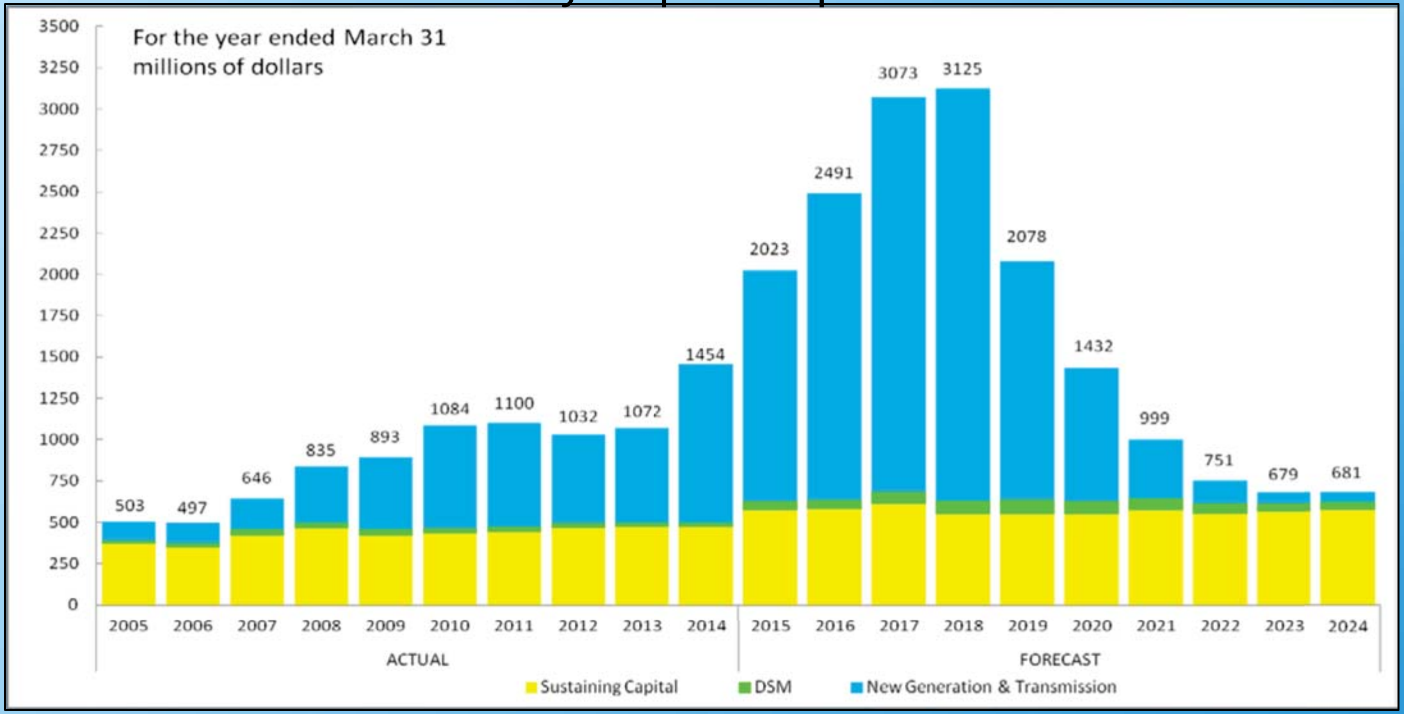


- Investment is required to meet growing energy needs of Manitoba.
- Even with load reductions from the higher levels of Power Smart investment, demand for electricity is continuing to grow due to increases in population, higher average energy usage and industrial & commercial customer expansion.

Manitoba Hydro

Manitoba Hydro is Entering a Period of Extensive Capital Investment

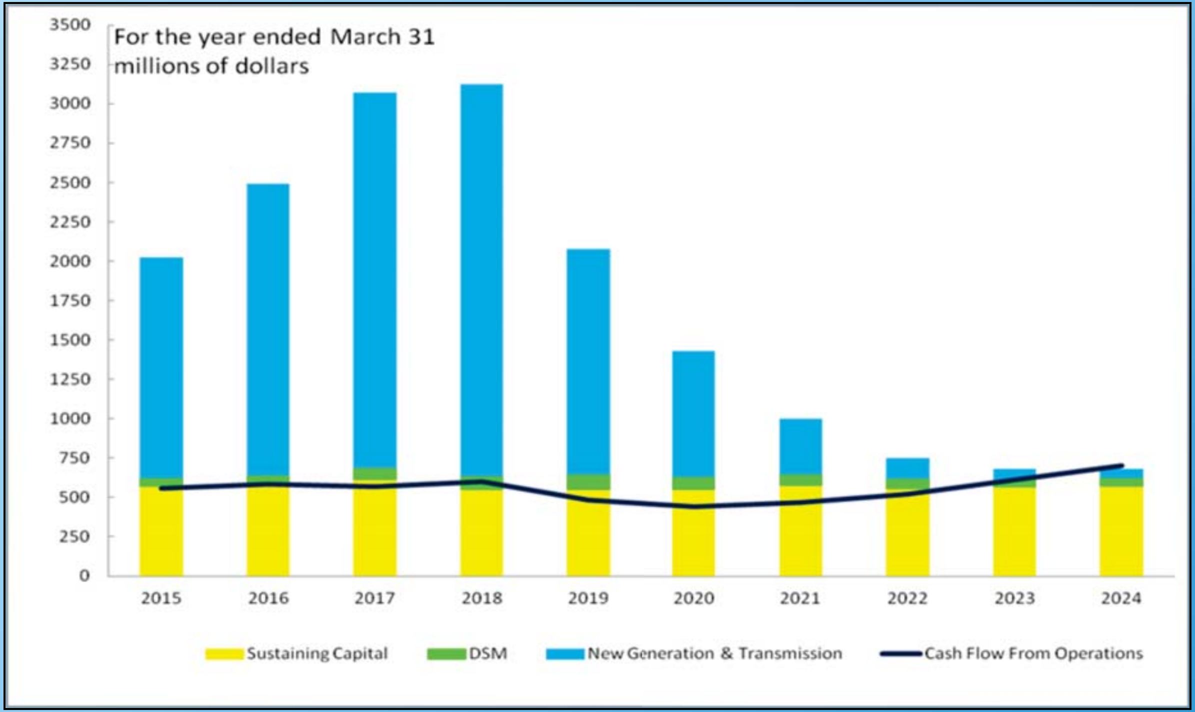
Electricity Capital Expenditures



- Investment is required to replace aging utility assets and address capacity constraints on the system.
- The level of total investment will be significantly higher in the next 10 year period (peaks at $3.1 billion in 2017/18) than in the prior 10 years. Investment cost will be many multiples higher than the historic cost of the existing asset base.

Cash Flow from Operations will be Insufficient to Fund Capital Expenditures

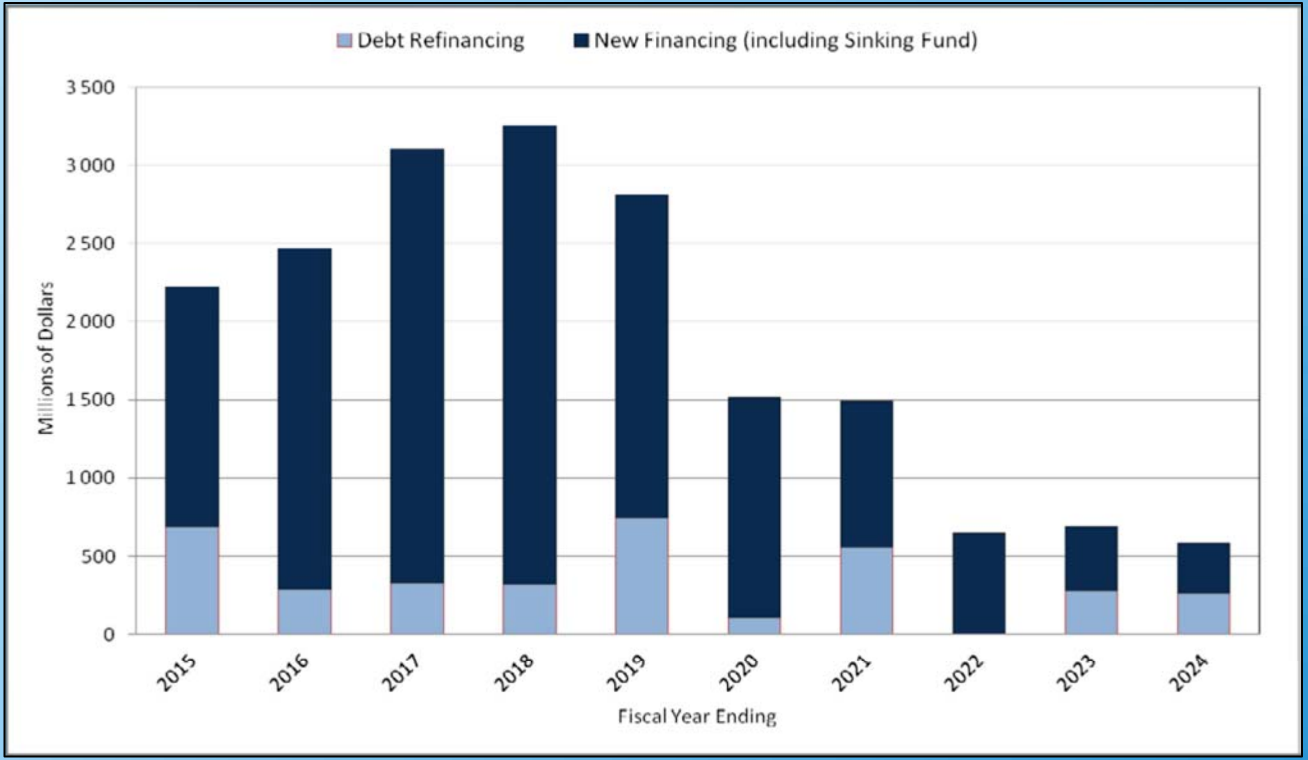
Electricity Capital Expenditures & Cash Flow from Operations



- Manitoba Hydro does not have access to share capital like private utilities and must rely on a combination of internally generated cash and debt financing to fund its capital investment program.
- Cash flow from operations (including projected rate increases) will not be sufficient to fully fund sustaining capital requirements and Major Generation & Transmission capital will be funded through debt financing.

Investment Requirements will Lead to Unprecedented Levels of Debt Financing

Projected Electric Operations Borrowing Requirements

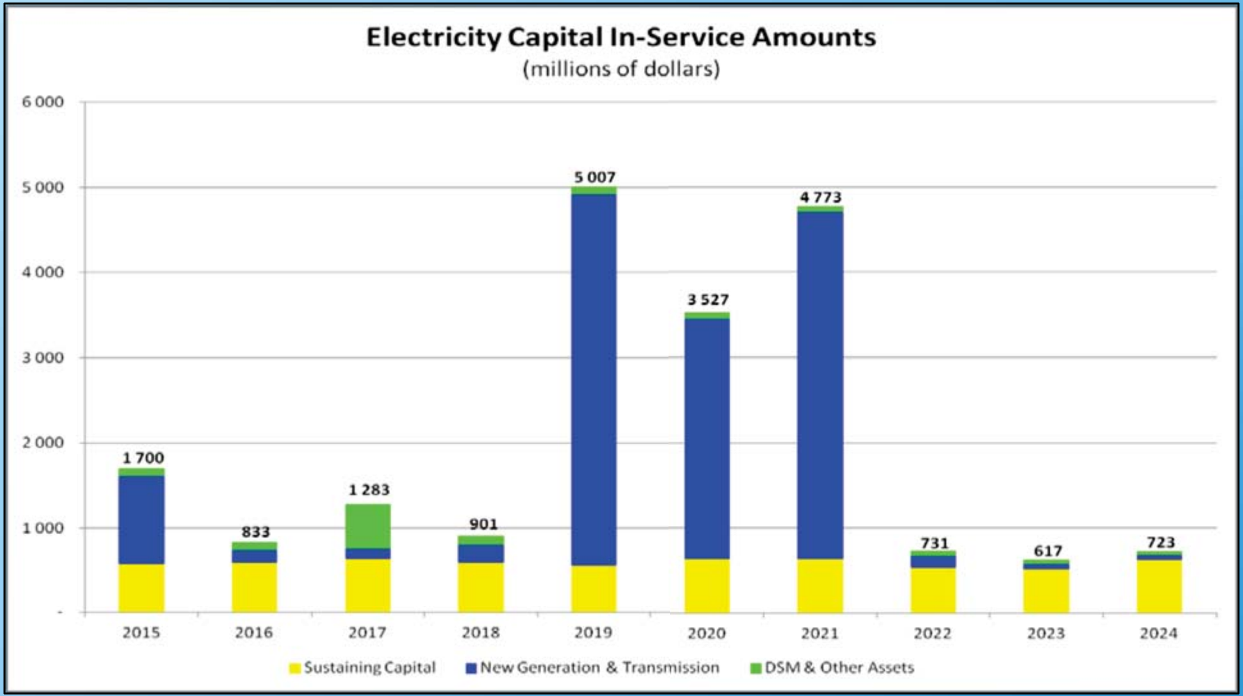


- Including debt refinancing requirements for existing debt, total debt requirements will peak at levels in excess of $3 billion per year – which are unprecedented levels in Manitoba Hydro history.

Manitoba Hydro

Reasons for Proposed Rate Increases

Revenue Requirements are Driven by Assets Being Placed into Service

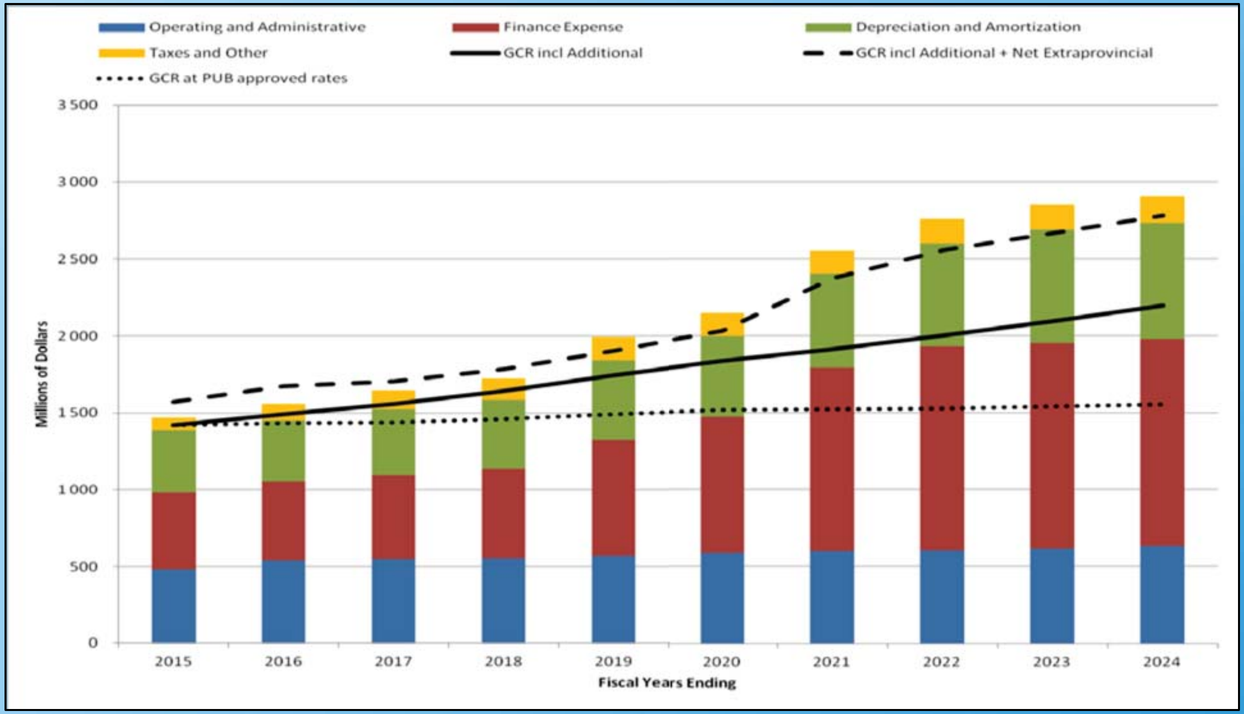


- Due to the capital intensive nature of Manitoba Hydro's operations, a significant portion of overall revenue requirements are carrying costs (finance expense, depreciation & capital taxes) of assets used to provide service, once they are placed into service.
- $3.8 billion of electric assets are projected to be placed into service between 2015 and 2017 and $20.1 billion between 2015 to 2024.

Manitoba Hydro

Carrying Costs on Electric Assets are Expected to Double in Next 10 Years

Electric Expenses Compared to Revenues

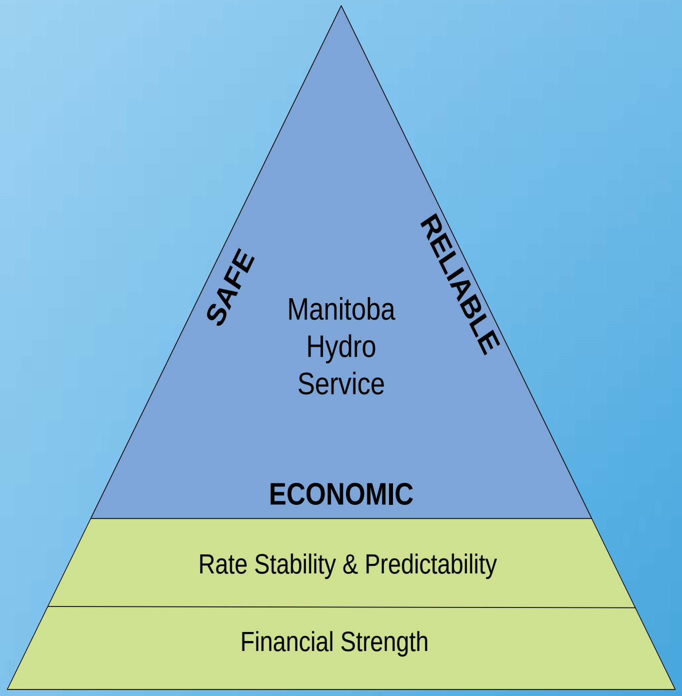


- Required capital investment is projected to double the asset base and carrying costs of electric operations in the next 10 years.
- Over the 10 year period, total electric costs are projected to double from $1.5 billion to $3 billion, primarily due to increased finance & depreciation costs. Operating costs are relatively constant.
- The proposed and indicative rate increases accumulate to 42% by 2024, thus resulting in projected losses of $900 million on electric operations between 2019 – 2024.

Manitoba Hydro

Rate Stability for Customers Dependent on Financial Strength of the Corporation

Foundation of Safe, Reliable and Economic Service



- Rate stability & predictability for customers depends on the continued financial strength of Manitoba Hydro.
- Without the necessary rate increases, there is significant risk to customers of volatile rate changes and a need for sudden or larger rate increases in the near future. This risk is particularly acute in the upcoming period of extensive capital investment.

Manitoba Hydro

Financial Strength is Measured through Consolidated Financial Targets

- Debt/Equity:
  - Maintain minimum debt/equity ratio of 75:25
- Interest Coverage:
  - Maintain interest coverage ratio of > 1.20
- Capital Coverage:
  - Maintain capital coverage ratio of > 1.20

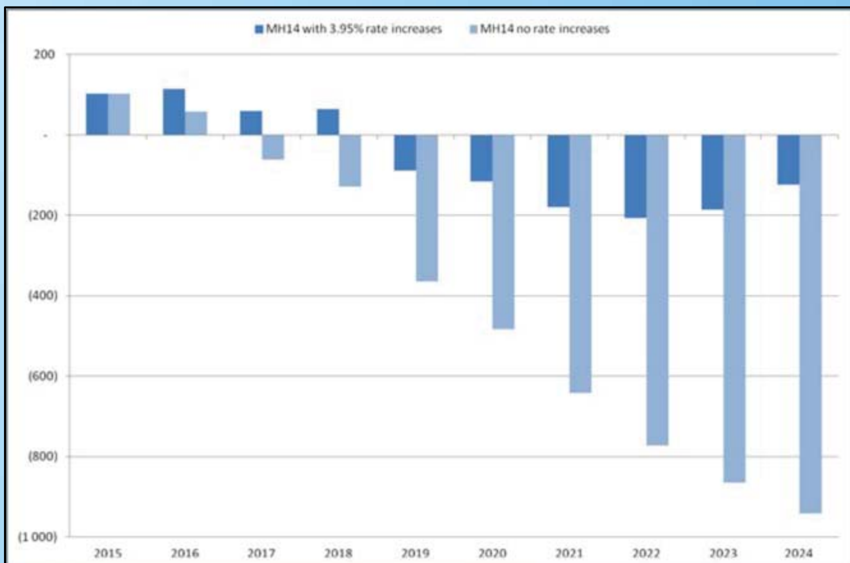
Note: Financial Targets may not be maintained during years of major investment in the generation and transmission system.

Manitoba Hydro

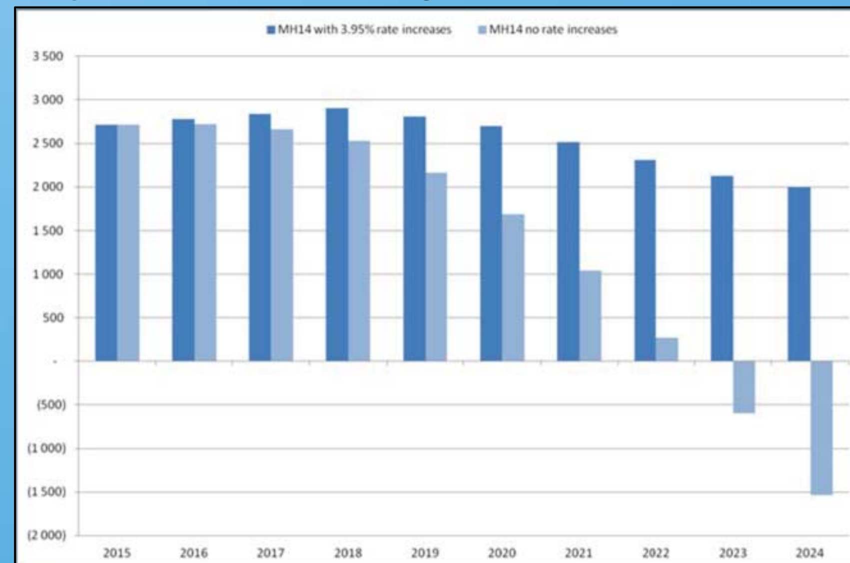
Investments in Capital Assets Will Place Pressure on Manitoba Hydro's Financial Strength

MH14 3.95% Rate Increases and MH14 No Rate Increases

Projected Net Income



Projected Retained Earnings

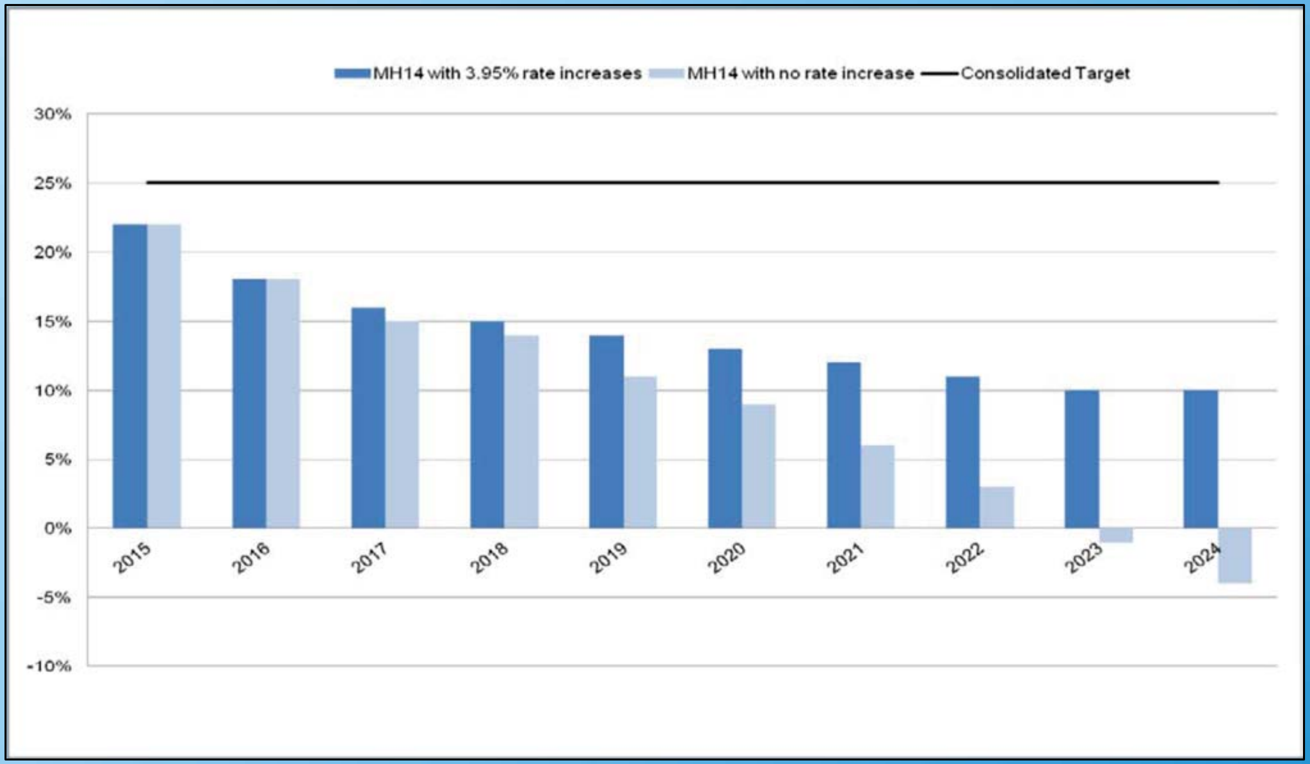


- The proposed and indicative 3.95% rate increases accumulate to 42% by 2024, but capital-driven carrying costs increase 100%, resulting in projected losses of $900 million between 2019 and 2024.
- Financial reserves (retained earnings) are projected to decrease from $2.7 billion to $2.0 billion by 2024.

Investments in Capital Assets Will Place Pressure on Manitoba Hydro's Financial Strength

MH14 3.95% Rate Increases and MH14 No Rate Increases

Projected Equity Ratio

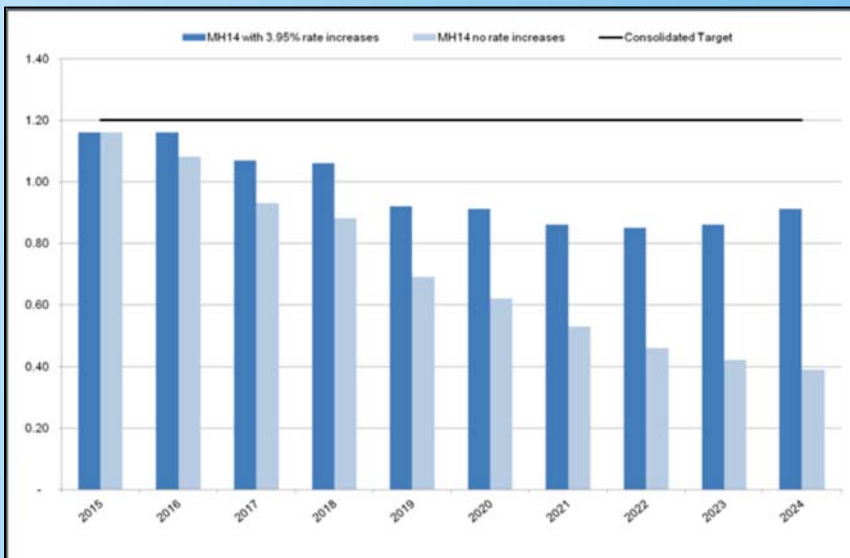


- Equity ratio is projected to deteriorate to 10% by 2023 – well below the 25% target level.

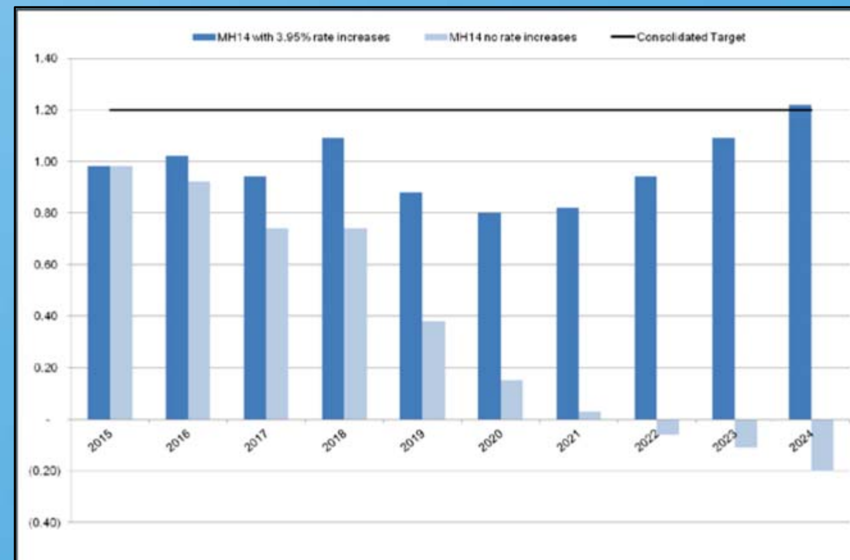
Investments in Capital Will Place Pressure on Financial Strength

MH14 3.95% Rate Increases and MH14 No Rate Increases

Projected Interest Coverage



Projected Capital Coverage Ratio

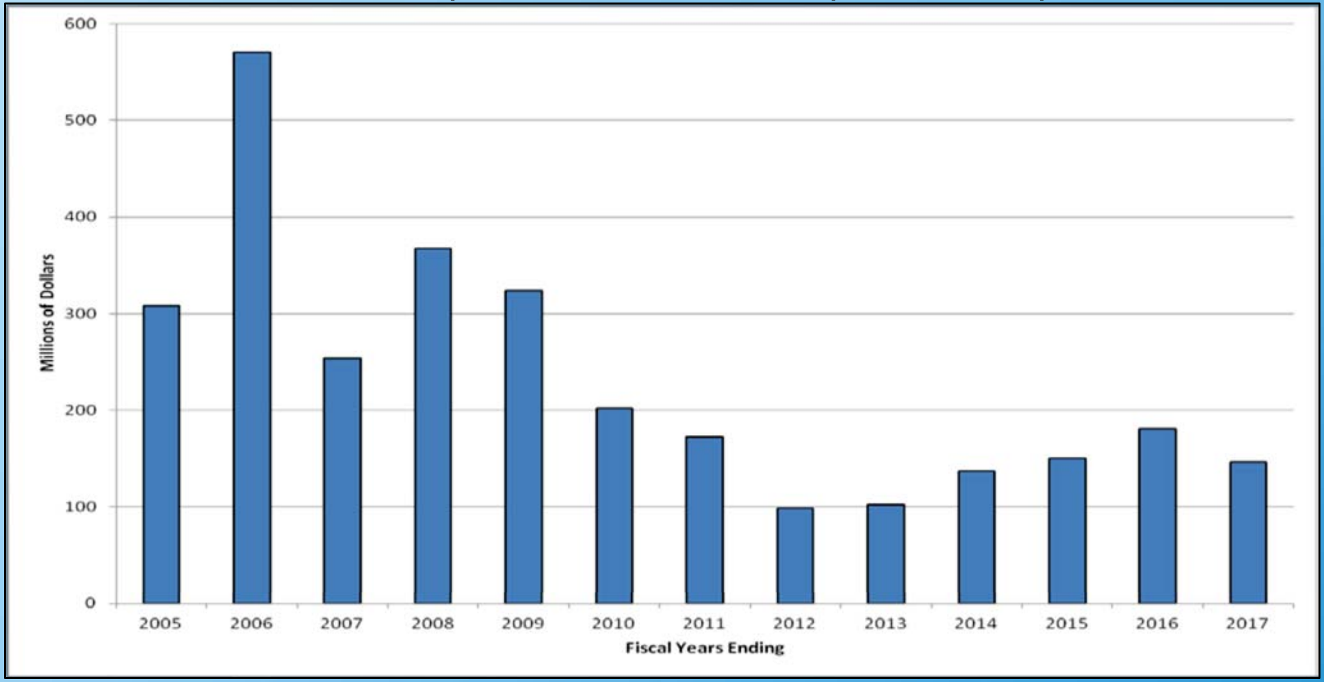


- Interest coverage and capital coverage are projected to be well below the target levels of 1.20 for most of the years of the forecast.

Manitoba Hydro

Rates Have Not Increased to Fully Compensate for Reductions in Net Extraprovincial Revenue

Net Extraprovincial Revenue (2015-2017)

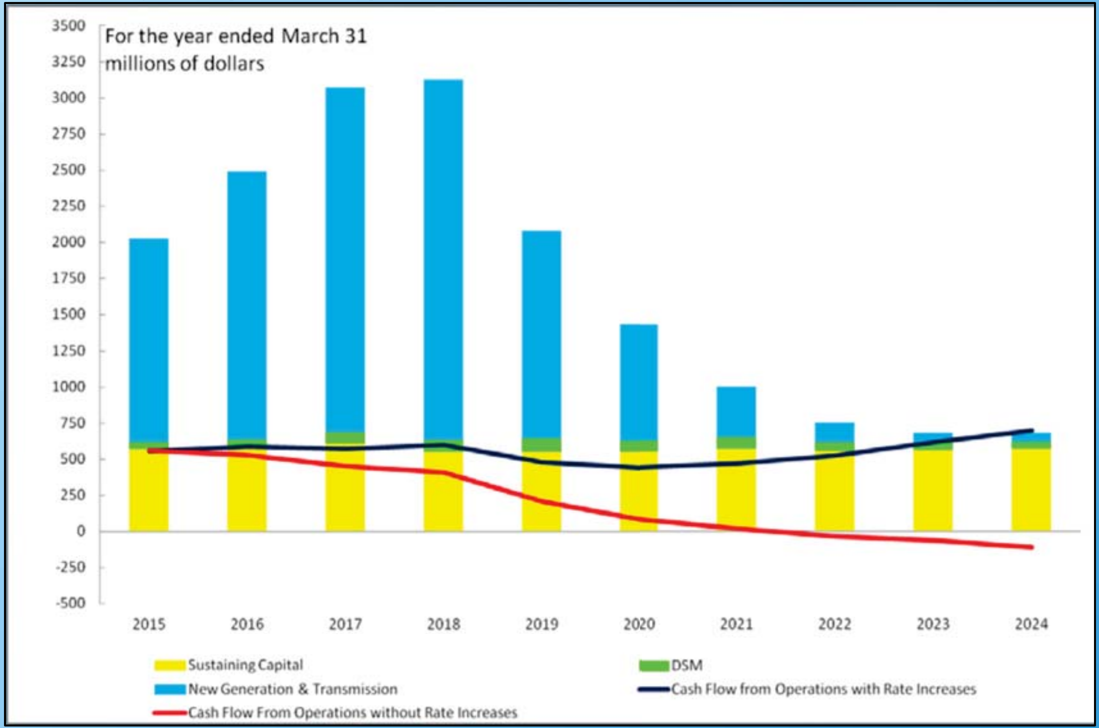


- Historically, Net Extraprovincial revenues have enabled Manitoba Hydro to maintain lower electricity rates for Manitobans (averaged $365 million/year between 2005-2009).
- Net extraprovincial revenues have not been as strong as in previous years (projected at $147 million to $181 million between 2015 to 2017).
- Rates need to gradually increase to compensate for this reduction.

Manitoba Hydro

Increased Borrowing Requirements Result in Higher Levels of Debt and Carrying Costs, which Need to be Recovered from Customers

Electricity Capital Expenditures & Cash Flow from Operations



- Without the proposed and indicative rate increases, Manitoba Hydro would be required to fund an increasing portion of its sustaining capital expenditures through debt financing as opposed to cash flow generated from operations.
- The proposed and indicative rate increases reduce the need for borrowing and additional financing costs that must be borne by customers through rates.

Manitoba Hydro

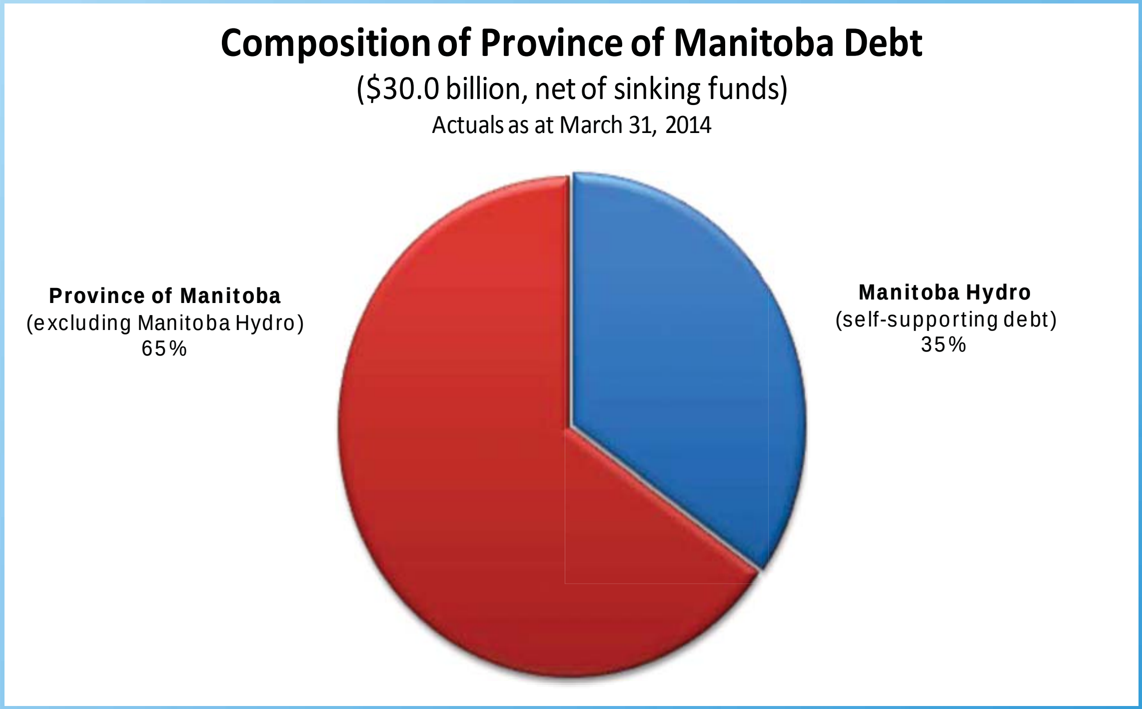
Potential Negative Implications to Provincial Credit Rating and Manitoba Hydro's Borrowing Costs

Provincial Long Term Credit Ratings Comparison

Province	Standard & Poors	DBRS	Moody's Investors Service
British Columbia	AAA	AA (high)	Aaa
Saskatchewan	AAA	AA	Aaa
Alberta	AAA	AAA	Aaa
Manitoba	AA	A (high)	Aa1
Ontario	AA-	AA (low)	Aa2
Nova Scotia	A+	A (high)	Aa2
Newfoundland & Labrador	A+	A	Aa2
Québec	A+	A (high)	Aa2
New Brunswick	A+	A (high)	Aa2
Prince Edward Island	A	A (low)	Aa2

- The Province of Manitoba has a high credit rating that benefits Manitoba Hydro customers by reducing the cost of borrowing that customers pay in rates.

Potential Negative Implications to Provincial Credit Rating and Manitoba Hydro's Borrowing Costs



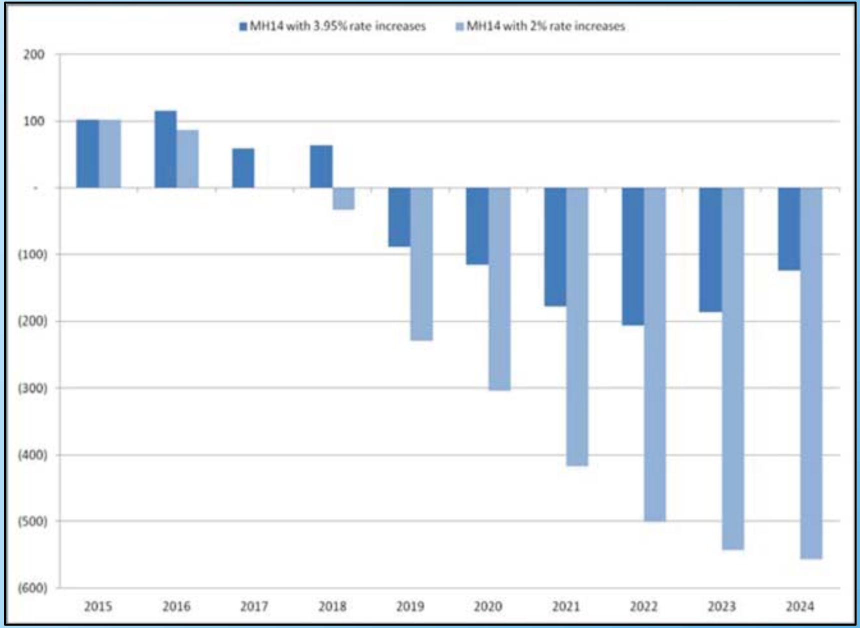
- Manitoba Hydro's debt forms a significant portion of total provincial debt and the Corporation's financial performance is a contributing factor toward the stability of the Province's credit rating.
- The proposed and indicative rate increases are necessary to continue to demonstrate to credit rating agencies that the regulatory framework in Manitoba is supportive of Manitoba Hydro's self-supporting financial status.

Manitoba Hydro

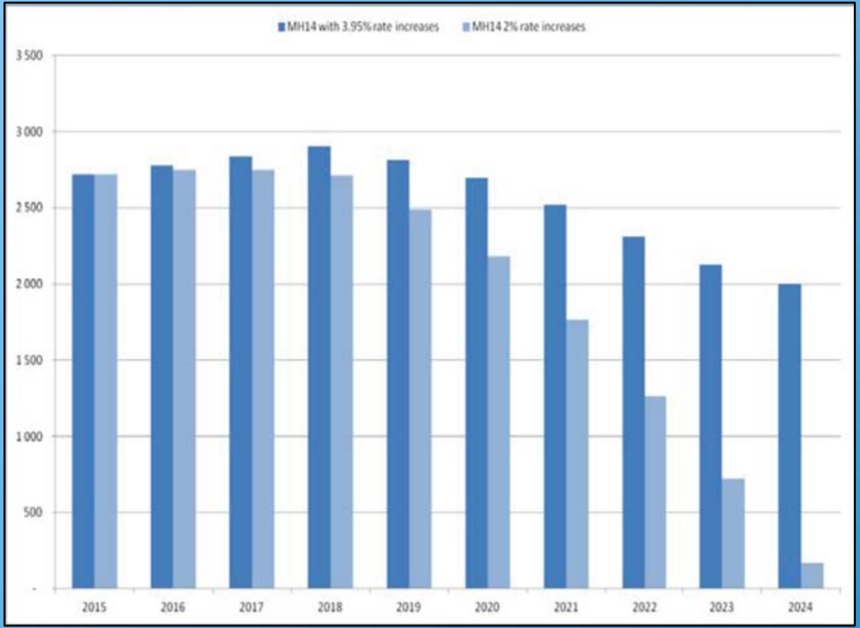
Inflationary Rate Increases are Not Sufficient to Maintain Rate Stability for Customers

Projected Net Income & Retained Earnings (2015-2024)
MH14 3.95% Rate Increases and MH14 2.0% Rate Increases

Projected Net Income



Projected Retained Earnings



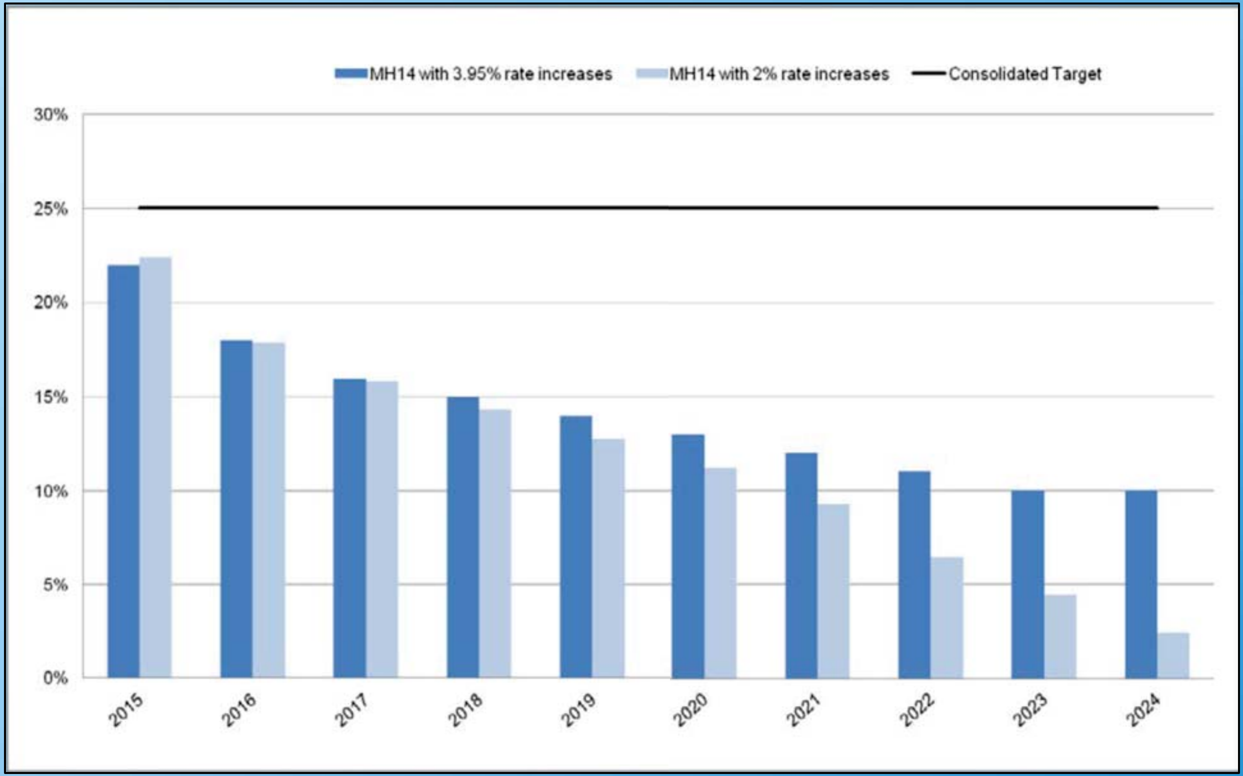
- Projected increases in Manitoba Hydro's revenue requirement are largely driven by the extensive investments made on behalf of customers – these are much more significant than inflationary cost pressures.
- Inflationary rate increases will jeopardize Manitoba Hydro's ability to provide rate stability to customers as it will be unable to recover its costs and ensure sufficient financial reserves are in place.

Manitoba Hydro

Inflationary Rate Increases are Not Sufficient to Maintain Rate Stability for Customers

MH14 3.95% Rate Increases and MH14 2.0% Rate Increases

Projected Equity Ratio



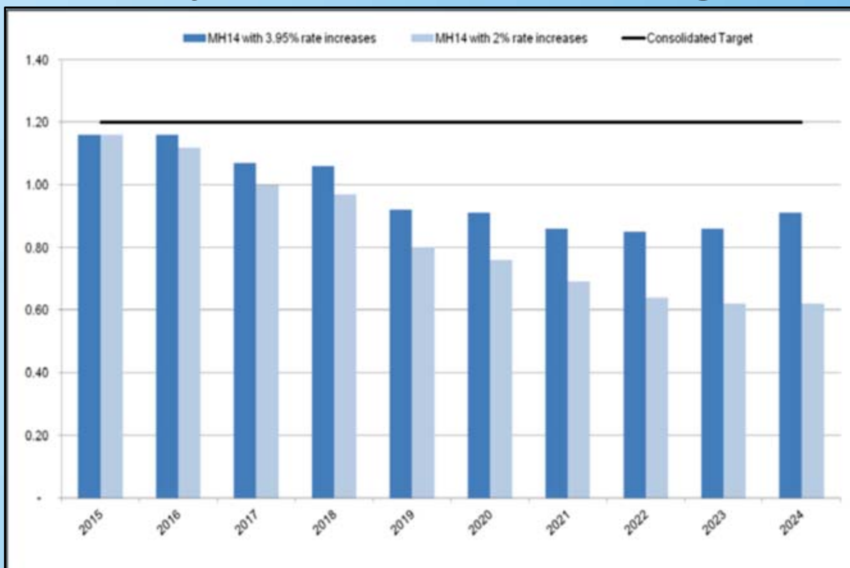
- Inflationary rate increases would result in an equity ratio well below minimum acceptable levels and approaching zero.

Manitoba Hydro

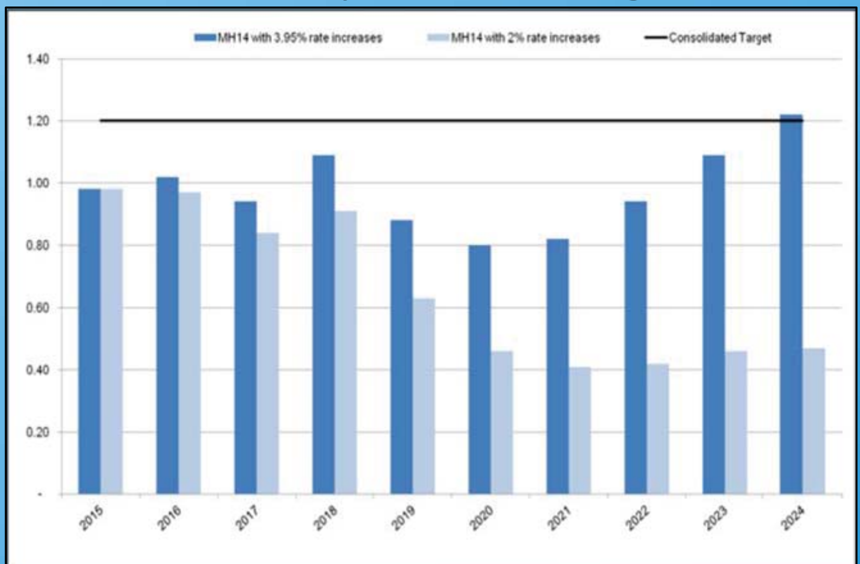
Inflationary Rate Increases are Not Sufficient to Maintain Rate Stability for Customers

MH14 3.95% Rate Increases and MH14 2.0% Rate Increases

Projected Interest Coverage



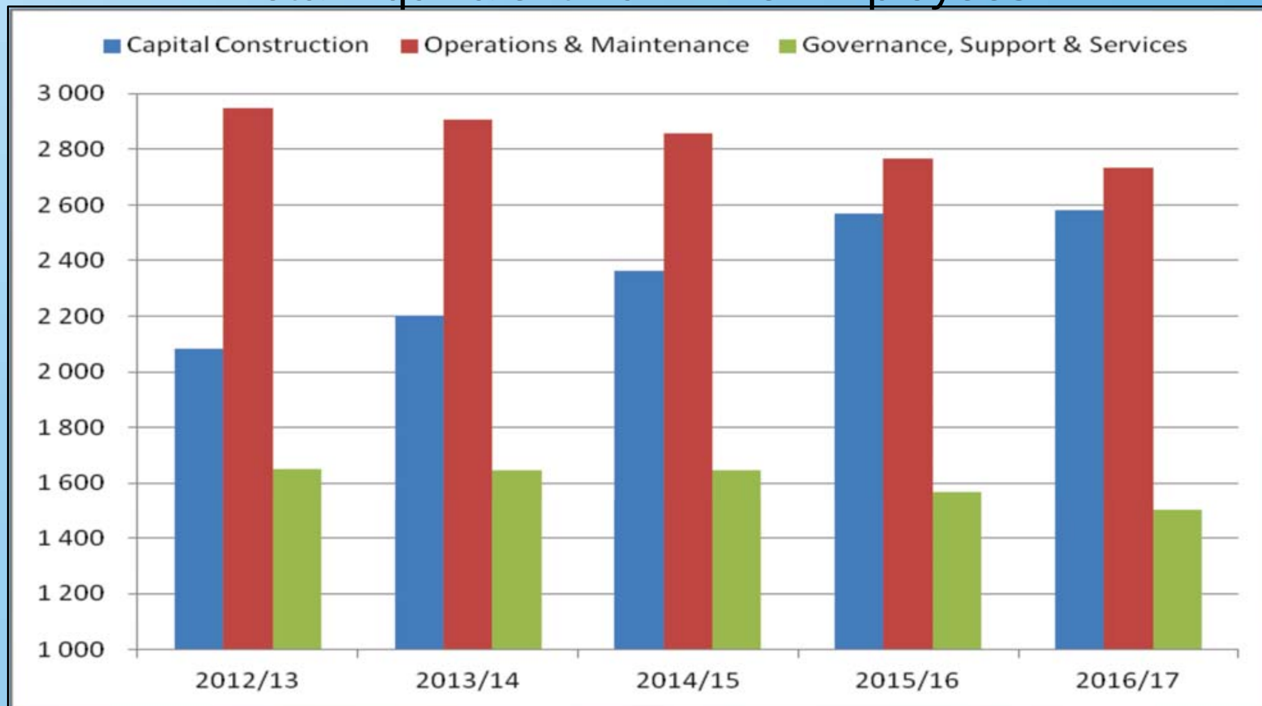
Projected Capital Coverage Ratio



- Inflationary rate increases would result in Interest and Capital Coverage ratios well below minimum acceptable levels.

Manitoba Hydro is Effectively Controlling Costs to Maintain Projected 3.95% Rate Increases

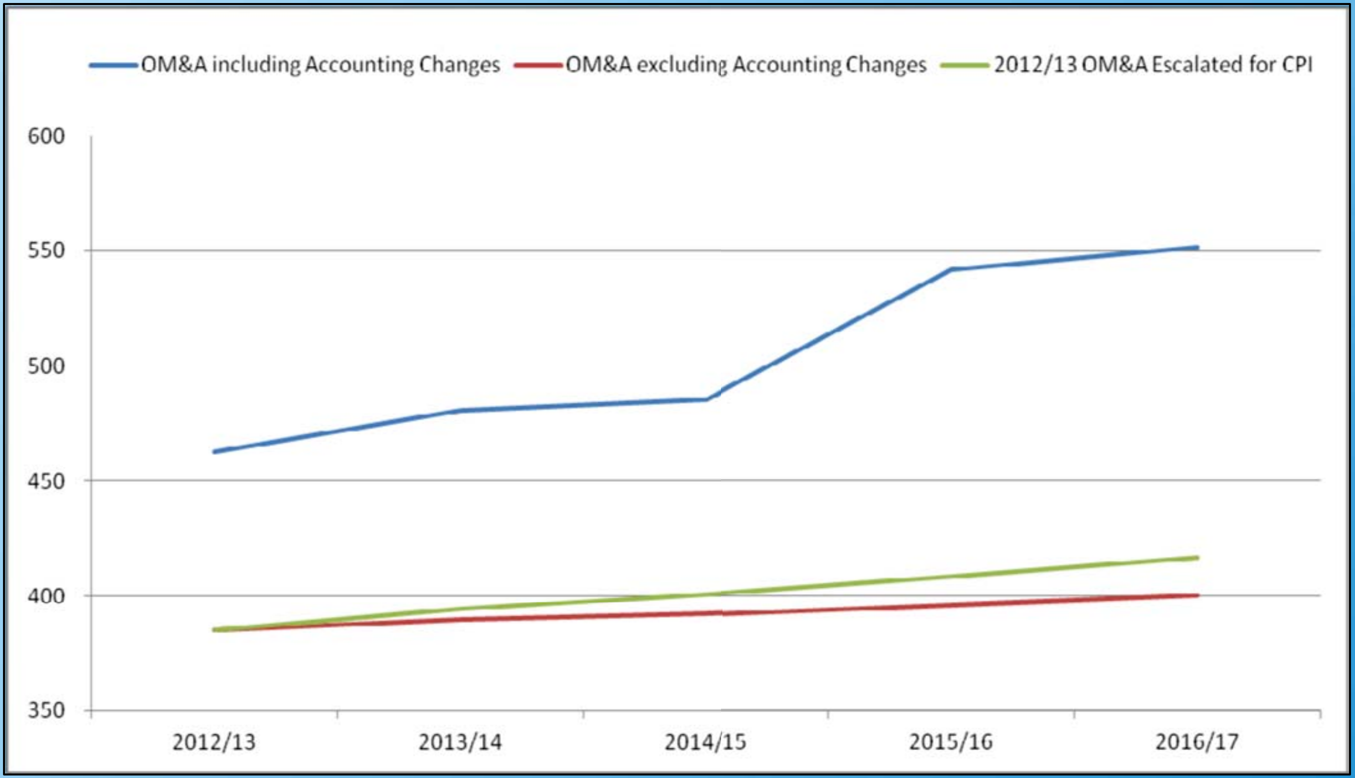
Total Equivalent Full Time Employees



- Manitoba Hydro is committed to carefully managing its costs and utilizing resources efficiently and effectively to provide maximum value to ratepayers.
- An extensive review of the staff compliment was undertaken in 2014 and resulted in plans to reduce approximately 330 operational positions over the 3 years between 2015 to 2017 which represents 7% of current EFTs charged to operating costs.
- Consistent with this plan O&M and Governance/Support/Services EFTs are projected to decrease. Capital Construction EFTs will increase due to the extensive capital program.

Manitoba Hydro is Effectively Controlling Costs to Maintain Projected 3.95% Rate Increases

Operating, Maintenance & Administrative Costs



- Operational position reductions and other cost saving initiatives will allow Manitoba Hydro to limit OM&A cost increases to 1% per year (below inflationary levels) excluding the impacts of accounting changes.
- This is consistent with the PUB's expectations from Order 43/13.

Manitoba Hydro

Manitoba Hydro is Projecting Deterioration of its Financial Ratios to Mitigate the Rate Increases to Customers

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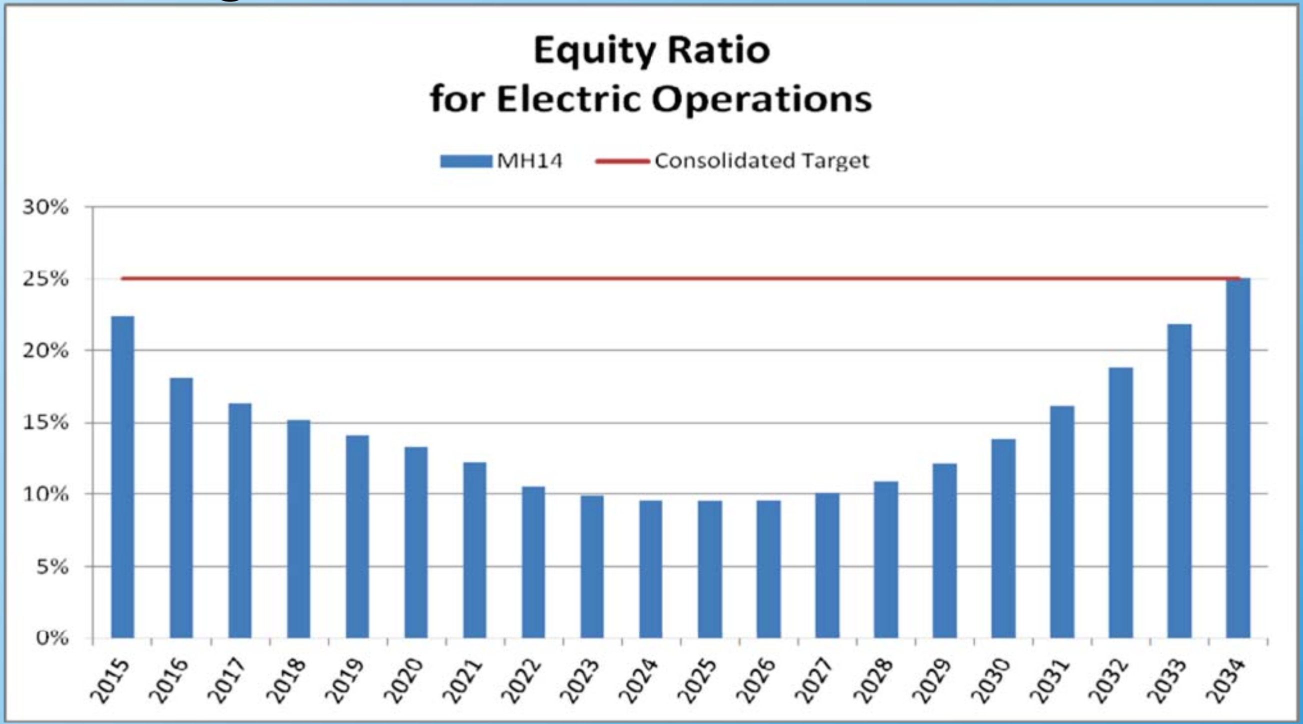


- Higher rate increases in the order of 5.5% to 6.0% for the next four years would be necessary to reduce the losses that are projected in the next 10 years and maintain financial reserves at current levels.
- The 3.95% proposed and indicative rate increases are the minimum that are necessary to manage the deterioration in projected financial results and ratios in the next 10 years.
- Relaxing the longer term financial targets will not negate the need for the requested rate increases of 3.95%.

Manitoba Hydro

NFAT Financial Panel

Darren Rainkie – Vice-President, Finance & Regulatory
Manny Schulz – Corporate Treasurer, Treasury Division
Greg Barnlund – Division Manager, Rates & Regulatory Affairs Division
Liz Carriere – Manager, Financial Planning Department

March 19, 2014

Presentation Summary

- Financial Profile
- Financial Outlook Update (IFF13)
- Rate Comparisons
- NFAT Financial and Rate Analysis
  - Impact on Rates
  - Uncertainty Analysis
  - Impact on Financial Position
  - Drought Analysis
- Financial Risk Management

Manitoba Hydro Financial Profile

Consolidated Income Statement

(Condensed $ millions)

	For the nine months ended December 31 2013	For the year ended March 31 2013	2012	2011	2010	2009	2008
REVENUES							
Electric - Manitoba	990	1 380	1 219	1 218	1 156	1 148	1 087
Extraprovincial	338	353	363	398	427	623	625
Gas (Net)	99	147	132	143	138	149	142
	1 427	1 880	1 714	1 759	1 721	1 920	1 854
EXPENSES							
Operating and Administrative	405	533	481	463	440	429	381
Finance Expense	349	489	423	425	410	471	440
Depreciation and Amortization	334	423	381	393	384	368	349
Water Rentals and Assessments	95	118	119	120	121	123	124
Fuel and Power Purchased	105	133	146	106	104	176	134
Capital and Other Taxes	84	105	103	102	99	87	80
Non-controlling Interest	(17)	(13)	-	-	-	-	-
	1 355	1 788	1 653	1 609	1 558	1 654	1 508
Net Income	72	92	61	150	163	266	346
Net Extraprovincial Revenue	138	102	98	172	202	324	367
Interest Coverage Ratio*	1.33	1.15	1.10	1.27	1.32	1.49	1.69

*The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Interest coverage ratio represents net income plus interest on debt divided by interest.

Consolidated Balance Sheet

(Condensed $ millions)

	As at December 31	As at March 31					
	2013	**2013**	**2012**	**2011**	**2010**	**2009**	**1990**
Property, Plant and Equipment (net)	10 665	10 541	8 647	8 215	8 076	7 944	2 677
Construction in Progress	2 658	1 967	3 150	2 739	2 052	1 438	1 206
	13 323	12 508	11 797	10 954	10 128	9 382	3 883
Current and Other Assets	1 898	1 682	1 622	1 646	1 487	1 499	812
Total Assets	15 221	14 190	13 419	12 600	11 615	10 881	4 695
Long-Term Debt (Net)	10 187	8 977	8 729	8 335	7 406	7 002	3 557
Current and Other Liabilities	1 803	1 937	1 495	1 127	1 328	1 637	924
Retained Earnings	2 613	2 542	2 450	2 389	2 239	2 076	117
Other Equity	618	734	745	749	642	166	97
Total Liabilities & Equity	15 221	14 190	13 419	12 600	11 615	10 881	4 695
Debt/Equity Ratio*	76:24	75:25	74:26	73:27	73:27	77:23	95:5

*The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Debt-to-equity ratio represents debt (long-term debt plus notes payable minus sinking funds and temporary investments) divided by debt plus equity (retained earnings plus accumulated other comprehensive income plus contributions in aid of construction plus non-controlling interest).

Consolidated Cash Flow Statement

(Condensed $ millions)

	For the nine months ended December 31	For the year ended March 31					
	2013	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**
Cash provided by Operating Activities	452	589	567	595	589	688	633
Cash provided by Financing Activities	1 082	635	725	674	1 124	424	487
Cash used for Investing Activities	(1 289)	(1 242)	(1 312)	(1 373)	(1 698)	(1 086)	(988)
Capital Coverage Ratio*	1.41	1.25	1.13	1.25	1.34	1.77	1.62

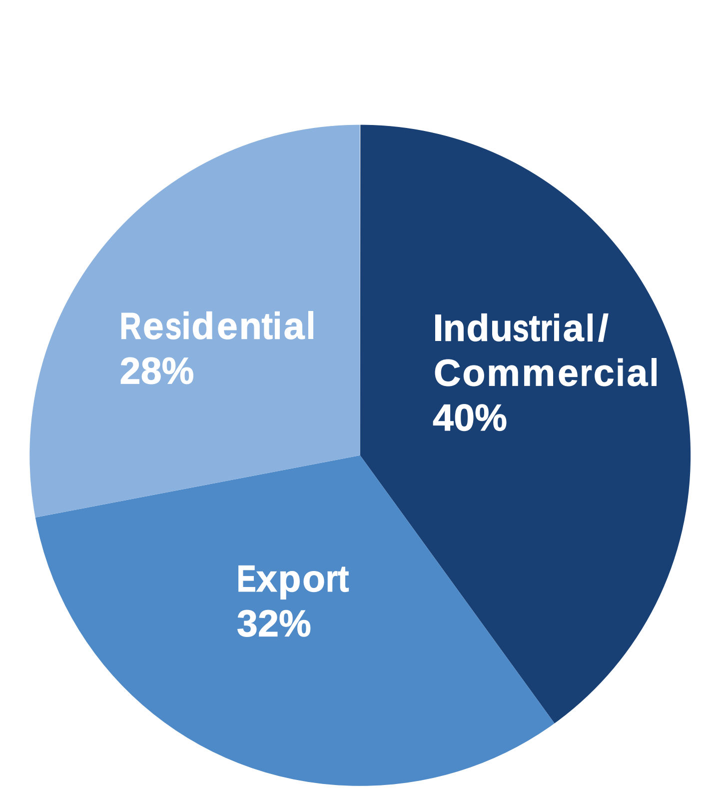
*The capital coverage ratio measures the ability of current period internally generated funds to finance capital expenditures excluding major new generation and related transmission. Capital coverage ratio represents internally generated funds divided by base capital expenditures.

Electric Operations Income Statement
($ millions)

	For the nine months ended December 31	
	2013	**2012**
REVENUES		
Electric - Manitoba	975	899
Extraprovincial	338	280
	1 313	1 179
EXPENSES		
Operating and Administrative	350	334
Finance Expense	322	333
Depreciation and Amortization	311	293
Water Rentals and Assessments	95	87
Fuel and Power Purchased	105	96
Capital and Other Taxes	69	65
Corporate Allocation	7	7
Non-controlling Interest	(17)	(8)
	1 242	1 207
Net Income	71	(28)

Revenue Sources – Electricity

2003/04 – 2012/13



Industrial/Commercial	$6.5 billion
Export	$5.1 billion
Residential	$4.5 billion

Financial Profile Summary

- With Retained Earnings of $2.6 billion, Manitoba Hydro is in the strongest financial position in its history.
- The Export Revenues associated with Manitoba Hydro’s predominantly hydro system has been a key contributor to the Corporation’s financial strength and affordable rates for customers.
- Manitoba Hydro is well positioned to make the necessary investments to meet the future energy needs of the Province.

Manitoba Hydro
Financial Outlook Update

(IFF13 February 2014)

Major Changes since IFF12 Approved in November 2012

- Load Forecast lower due to lower forecasted population growth. Gross firm energy is projected to be down 717 GW.h in 2022/23 and 1 159 GW.h in 2031/32 compared to IFF12.
- Conawapa in-service date deferred 1 year to 2026/27.
- Increased capital costs $1.6B due to Conawapa deferral, reinstatement of DSM costs into Capital Forecast and project estimate updates.
- 2013 Electric Export Price forecast projects on-peak prices to decrease on average 3% over the period 2014/15 to 2032/33.
- IFRS Implementation deferred 1 year to 2015/16 and assumption that rate-regulated accounting will continue over the forecast period.
- Forecast operating cost growth has been further constrained to 1% inflationary growth between 2016 and 2021.

Comparison of IFF13 to IFF12 Consolidated Net Income ($ Millions)

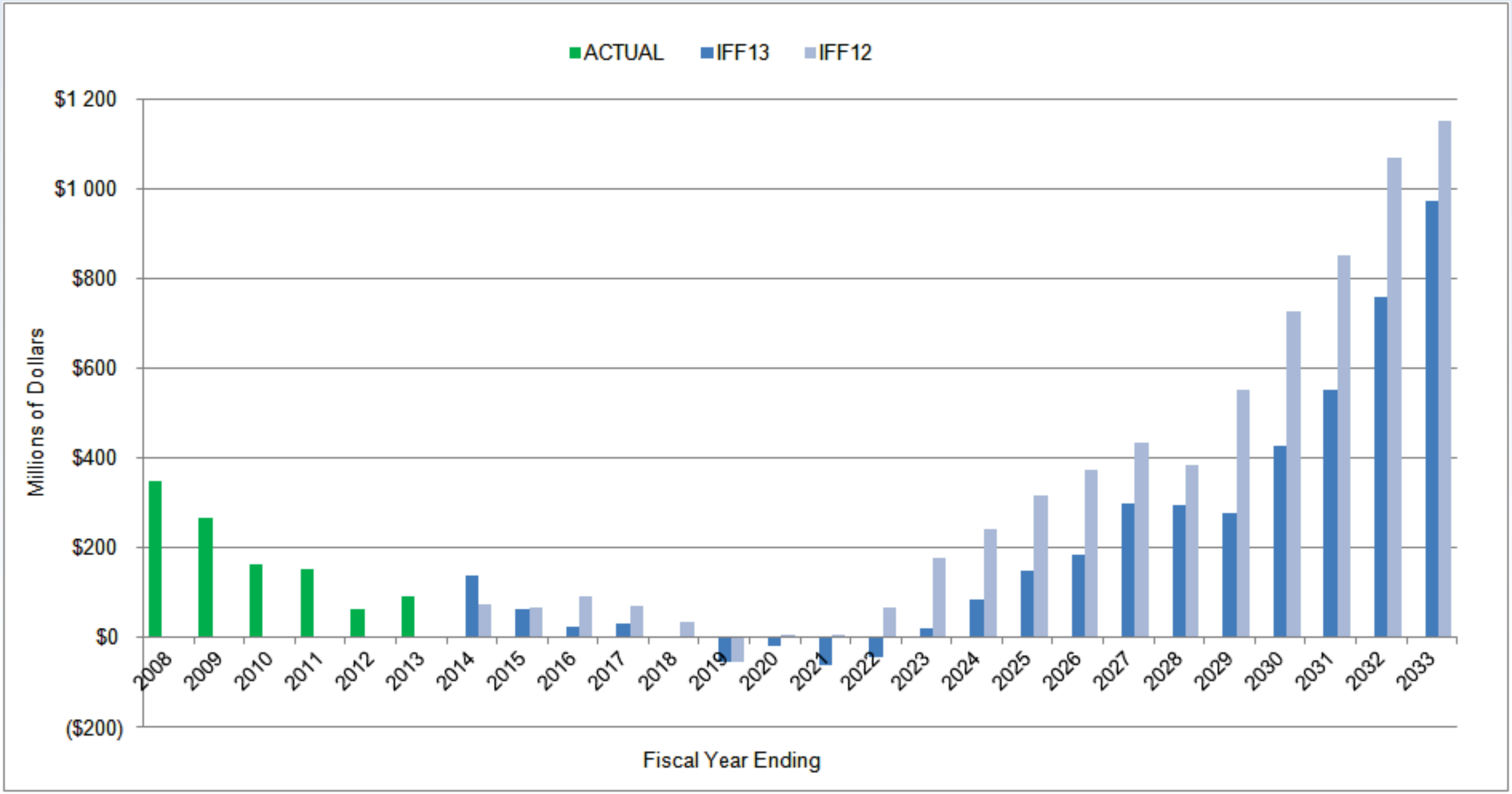
Increases (Decreases)

	2013/14	2014/15	2015/16	Cumulative to 2022/23	Cumulative to 2032/33
IFF12 Net Income	**72**	**66**	**90**	**529**	**6 621**
Manitoba Revenue (net of cost of gas)	(31)	(45)	(50)	(443)	(1 438)
Extraprovincial Revenue					
(net of water rentals and fuel & power purchases)	77	65	(1)	311	203
	46	20	(51)	(132)	(1 234)
Expenses	(17)	24	16	386	1 483
Change in Net Income @ IFF12 Rate Increases	63	(4)	(68)	(518)	(2 717)
Impacts of IFF13 Rate Increases	-	-	2	80	171
Total Change in Net Income from IFF12	63	(4)	(66)	(438)	(2 546)
IFF13 Net Income	**136**	**62**	**24**	**91**	**4 076**

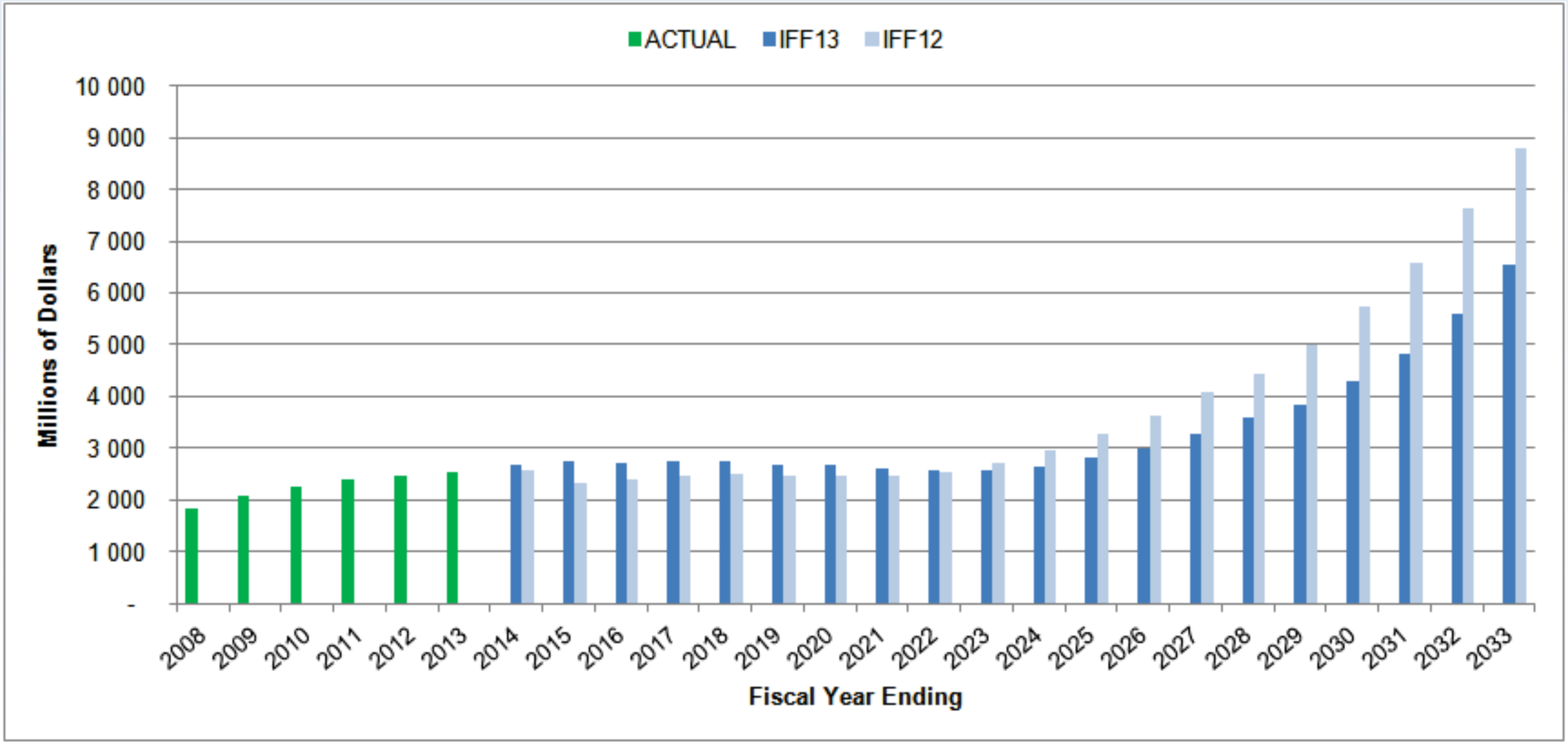
Consolidated Net Income

($Millions)

246



Retained Earnings
($Millions)



Financial Targets

Debt/Equity:

Maintain minimum debt/equity ratio of 75:25

Interest Coverage:

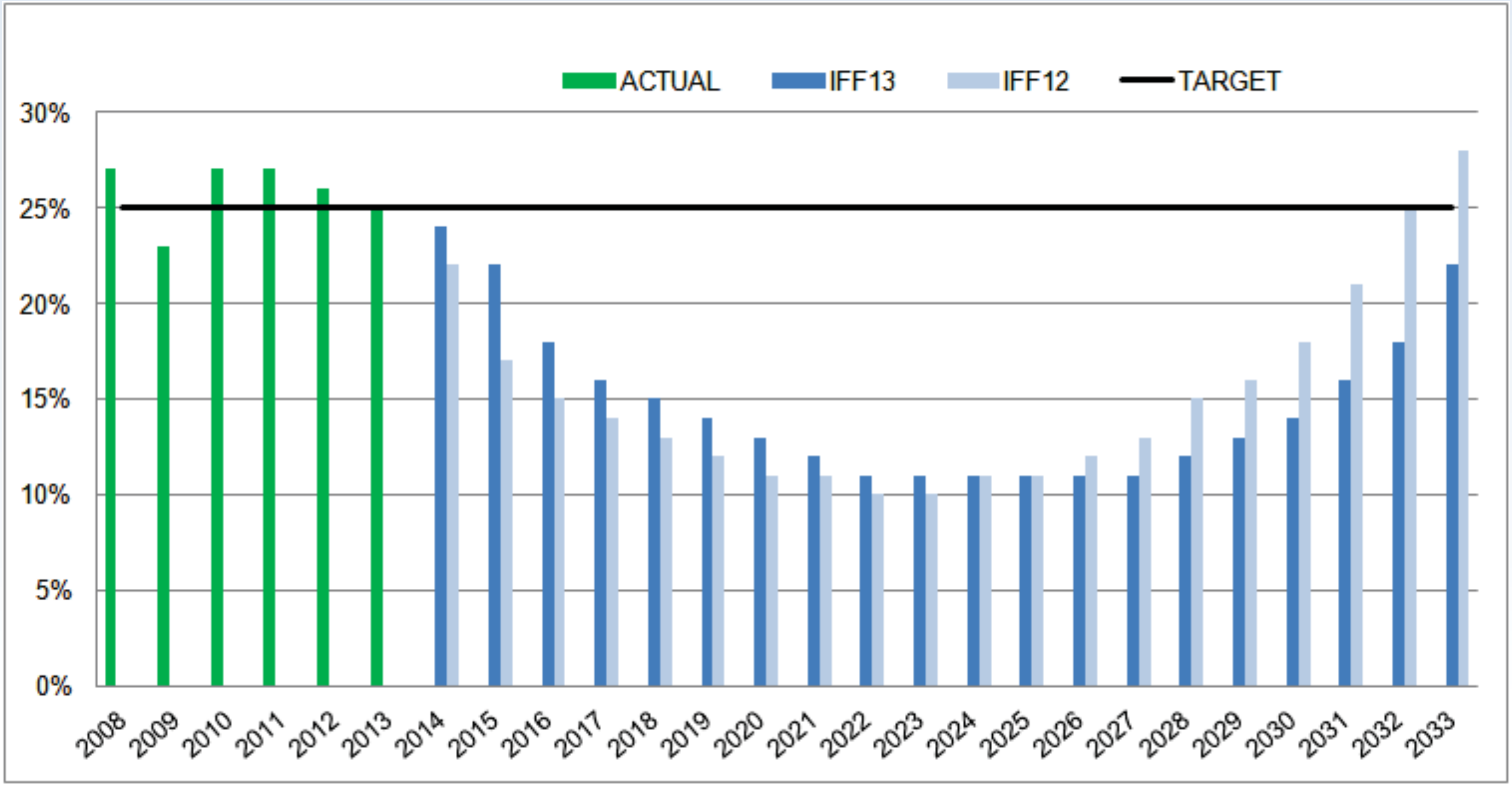
Maintain interest coverage ratio of > 1.20

Capital Coverage:

Maintain capital coverage ratio of >1.20

Note: Financial targets may not be maintained during years of major investment in the generation and transmission system.

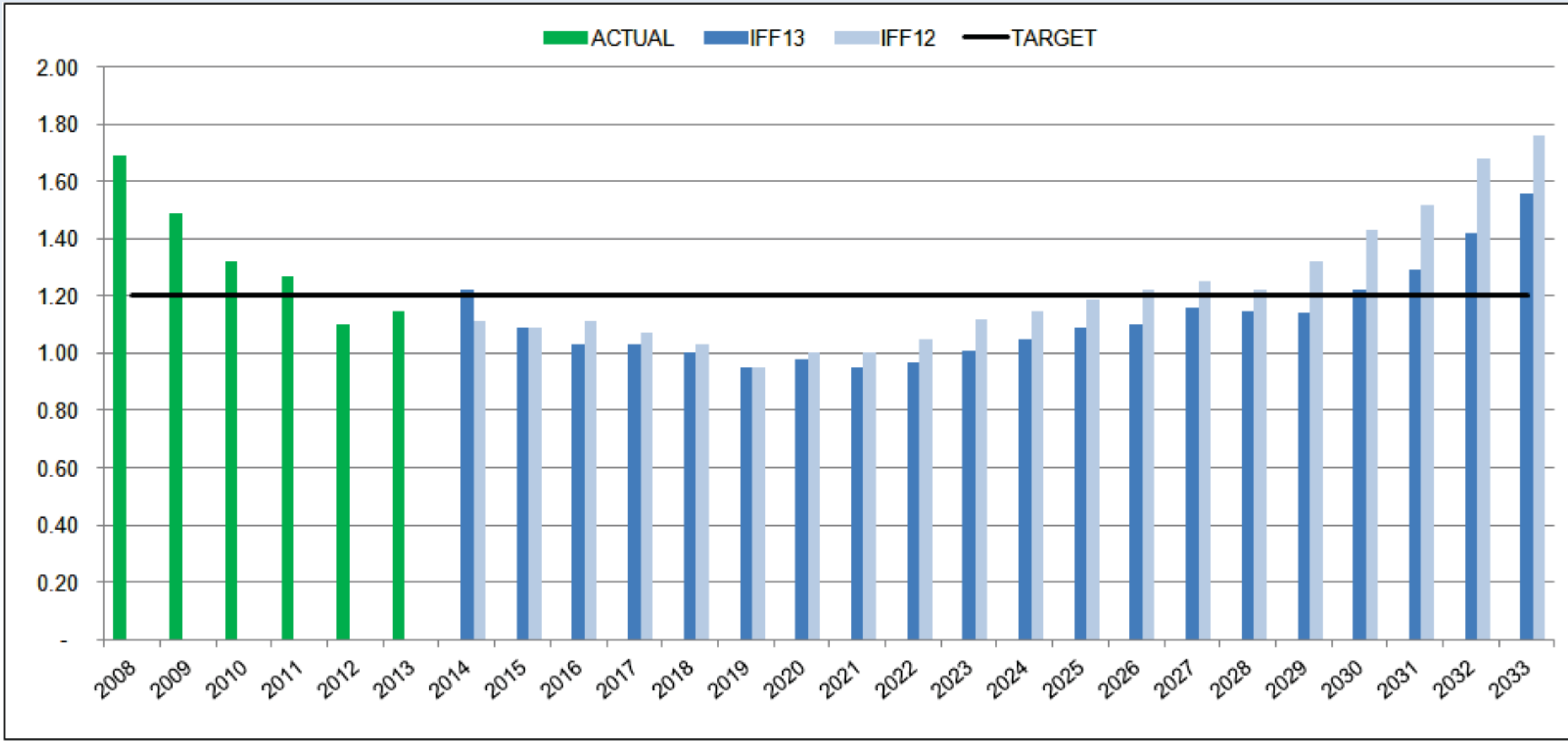
Equity Ratio



Note: 25% equity target attained in 2034 in IFF13

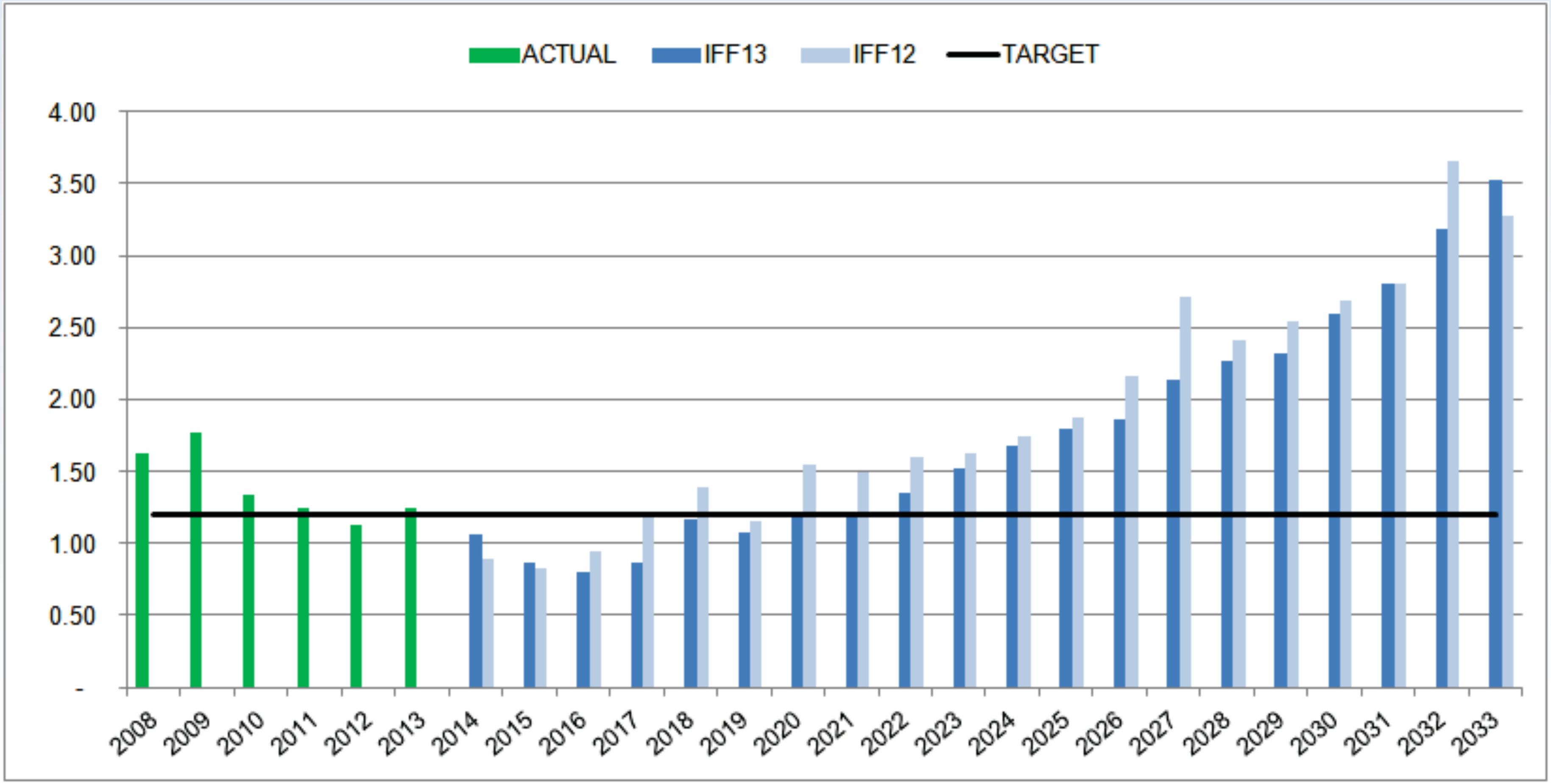
Manitoba Hydro

Interest Coverage Ratio



Capital Coverage Ratio

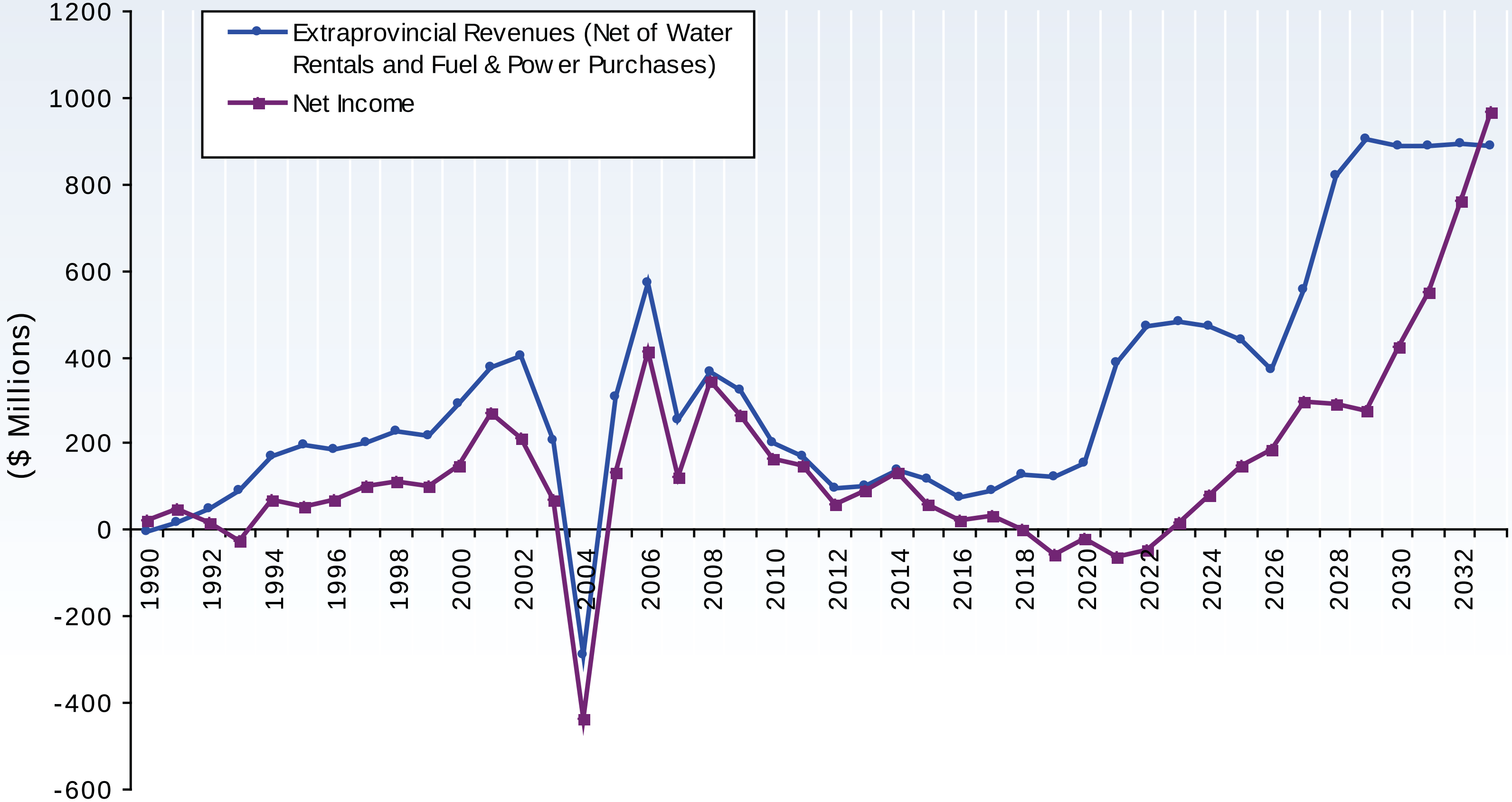
251



Consolidated Income Statement –

Comparison of Net Extraprovincial Revenues to Net Income

252



Financial Outlook Summary

- The required investments in existing infrastructure and new generation are expected to place pressure on Manitoba Hydro's key financial ratios in the next decade.
- Significantly higher rate increases than 3.95% would be required to maintain financial targets during the investment period.
- In setting financial targets, it has always been recognized that the targets may not be attained during periods major investments in the generation and transmission system.
- Credit rating agencies and other stakeholders are prepared to accept short-term weakness in financial ratios, as long as Manitoba Hydro can demonstrate progress to attaining the targets over the long-term.
- Financial ratios are expected to recover after the in-service of Keeyask and Conawapa generating stations and reach target levels within a forecast horizon of approximately 20 years.
- Export revenues will continue to play an important role in improving the Corporation's financial strength and keeping rates affordable for customers in the future.

NFAT Financial and Rate Analysis

Impact on Manitoba Hydro's Customer Rates

Financial Evaluation Assumptions & Methodology

- Financial evaluation compares the year-by-year impacts of each of the development plans on Manitoba Hydro's projected financial statements and customer rates.
- Overlays development plan assumptions on the revenue and cost, balance sheet and cash flow projections for the entire electric operations, including existing infrastructure.
- Development plans are evaluated by extending IFF12 and modifying for preliminary 2013 forecast of electricity export prices
- IFF12 (adjusted) is modified for the generation costs and transmission associated with the type of facility and timing for each development plan

Financial Evaluation Assumptions & Methodology

- Capital costs are reflected in the balance sheet
  - Construction in progress until in-service
  - Property, plant & equipment following in-service
- Once in-service, capital costs are reflected on the income statement in depreciation on a straight-line basis over the useful life of the asset:
  - Hydro generation 20-125 years
  - Gas generation 30 years
  - Transmission substations 35 years
  - Transmission lines 50 years
- Incorporates the flow-related production costs and revenues associated with the facilities for each development plan
  - Production costs include import purchases, wind purchases, thermal fuel and direct operating costs of the facilities
  - Surplus energy, after serving domestic and firm exports, is assumed to be sold as firm (if available from dependable energy) and as opportunity (for any additional in excess of dependable).

Financial Evaluation Assumptions & Methodology

- Uses the same assumptions from economic evaluations converted from real to nominal dollars.
- General consumers revenue reflects sales to Manitoba customers, including load growth, at rates approved by the PUB
  - Does not change under differing development plans
- Annual borrowing requirements are calculated based on the cash flow surplus or deficit for each development plan based on both existing infrastructure and new generation and transmission associated with the specific development plan.
- Annual finance expense is calculated based on the existing debt portfolio plus the projected annual borrowing requirements.

Financial Evaluation Assumptions & Methodology

- General consumers revenue additional reflects the incremental revenue required to recover costs for both existing infrastructure and the development plan.
- Manitoba Hydro has a long-standing strategy of gradualism in its approach to developing rate proposals.
- Under cost of service regulation, cost recovery is smoothed out over time by absorbing some of the cost into retained earnings on a temporary basis, if prudent, allowing sufficient time for export revenue benefits to accrue.
- Due to the volume of projections evaluated, Manitoba Hydro applied a mechanical approach using a set of fixed parameters consistent with the Corporations financial targets to derive the annual rate adjustments – removes judgment and subjectivity.
- Given that a timely return to the targeted 75:25 debt/equity ratio is prudent, the financial analysis assumes even-annual rate increases in order to achieve the targeted debt/equity ratio by the end of 2031/32, similar to the approach used in IFF12.

Financial Evaluation Assumptions & Methodology

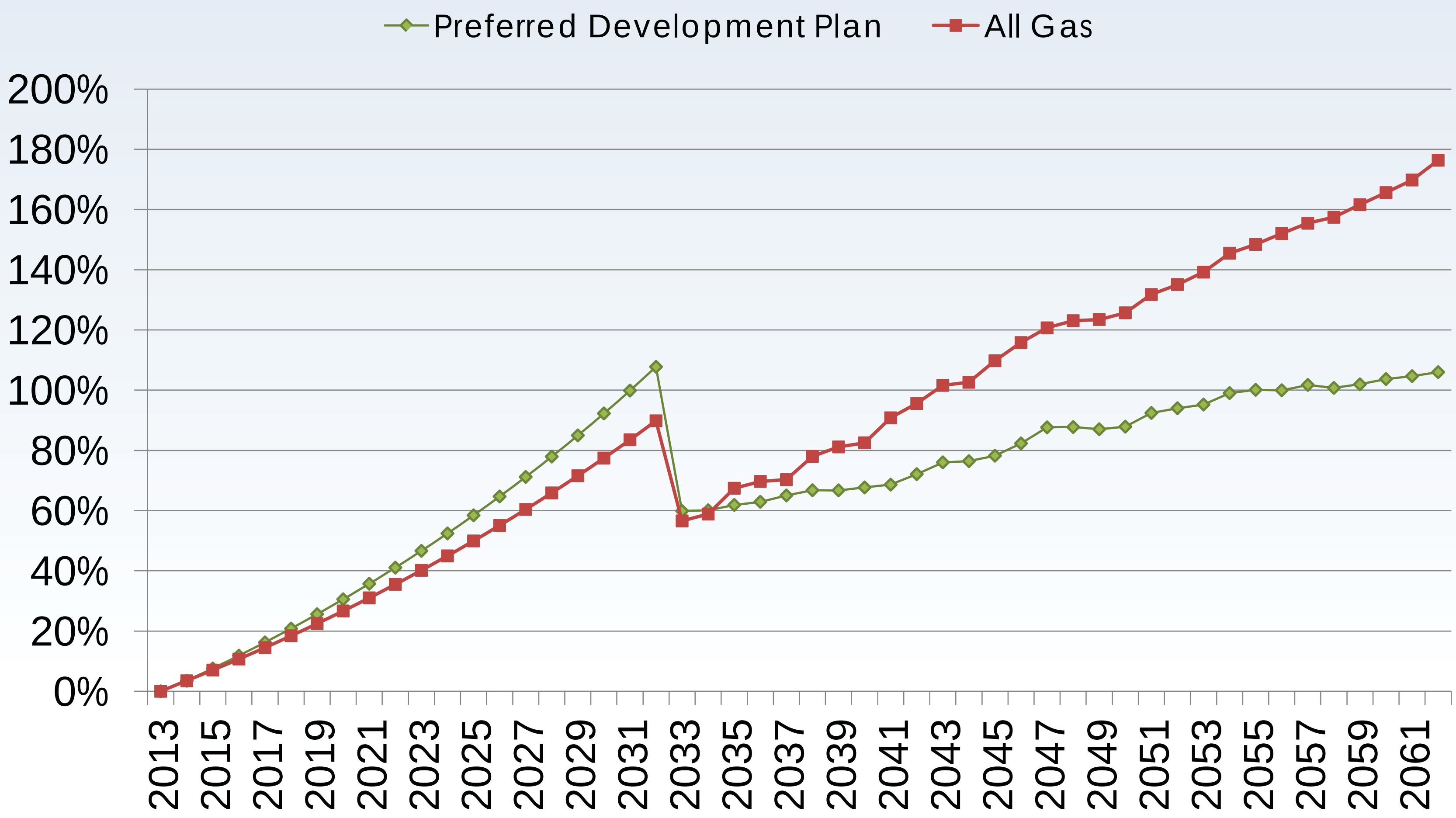
- Once the debt/equity target is reached, the projected comparative annual rates for the remainder of the 50-year financial forecast period are derived based on the corporation's interest coverage ratio target of 1.20.
- Strictly adhering to the financial targets results in projected rate increases that are at times well above the rate of inflation and at other times result in rate reductions – in practice, these would be smoothed over a period of time.
- Rate increases are indicative for comparability purposes between plans
- Actual rate increases will vary from those projected in this analysis and will be dependent upon future revenue requirements
- Numerous factors, other than the choice of development plan, may influence the revenue requirement, such as changing water flow conditions, weather, costs to maintain the system, and economic variables.
- Future rate proposals will be subject to full justification as part of General Rate Applications before the Public Utilities Board.

Financial Evaluation Assumptions & Methodology

- Approximately $1.2 and $0.4 billion is projected to be incurred to June/14 in nominal dollars to protect the early in-service dates of Keeyask and Conawapa, respectively.
- For NFAT financial evaluation purposes, a simplifying assumption was made to expense all sunk costs over an 18-year amortization period.
- If CEC or NFAT regulatory approvals are not received or the Corporation defers one or both plants, costs deemed to no longer provide future benefit must be expensed.
- Manitoba Hydro would periodically analyze the nature of the costs to determine their future benefit – some costs have longer expected future benefits while others have shorter.

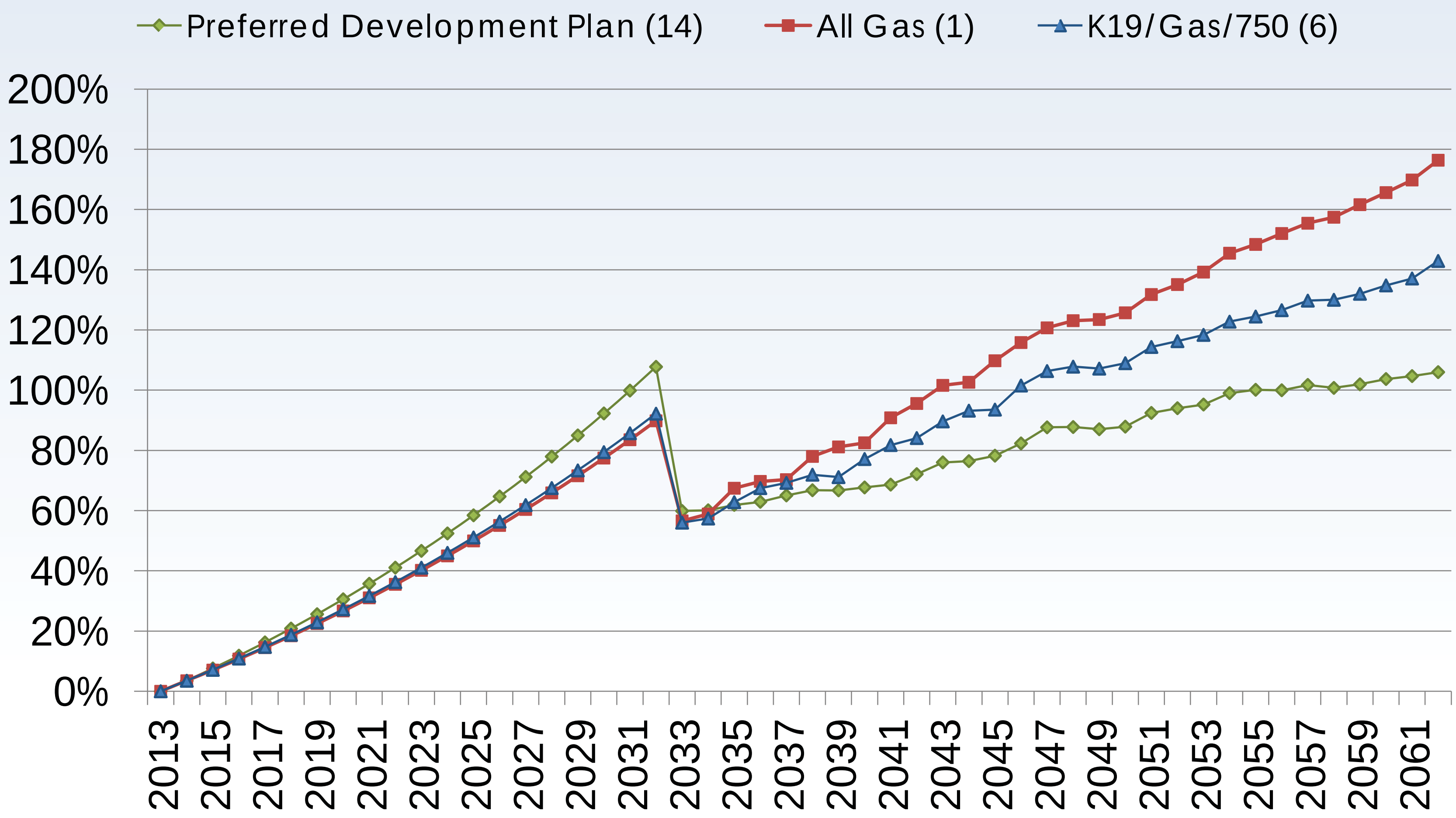
Cumulative Rate Increases (Nominal) Reference Scenario

Cumulative Rate Increases (Nominal) Reference Scenario



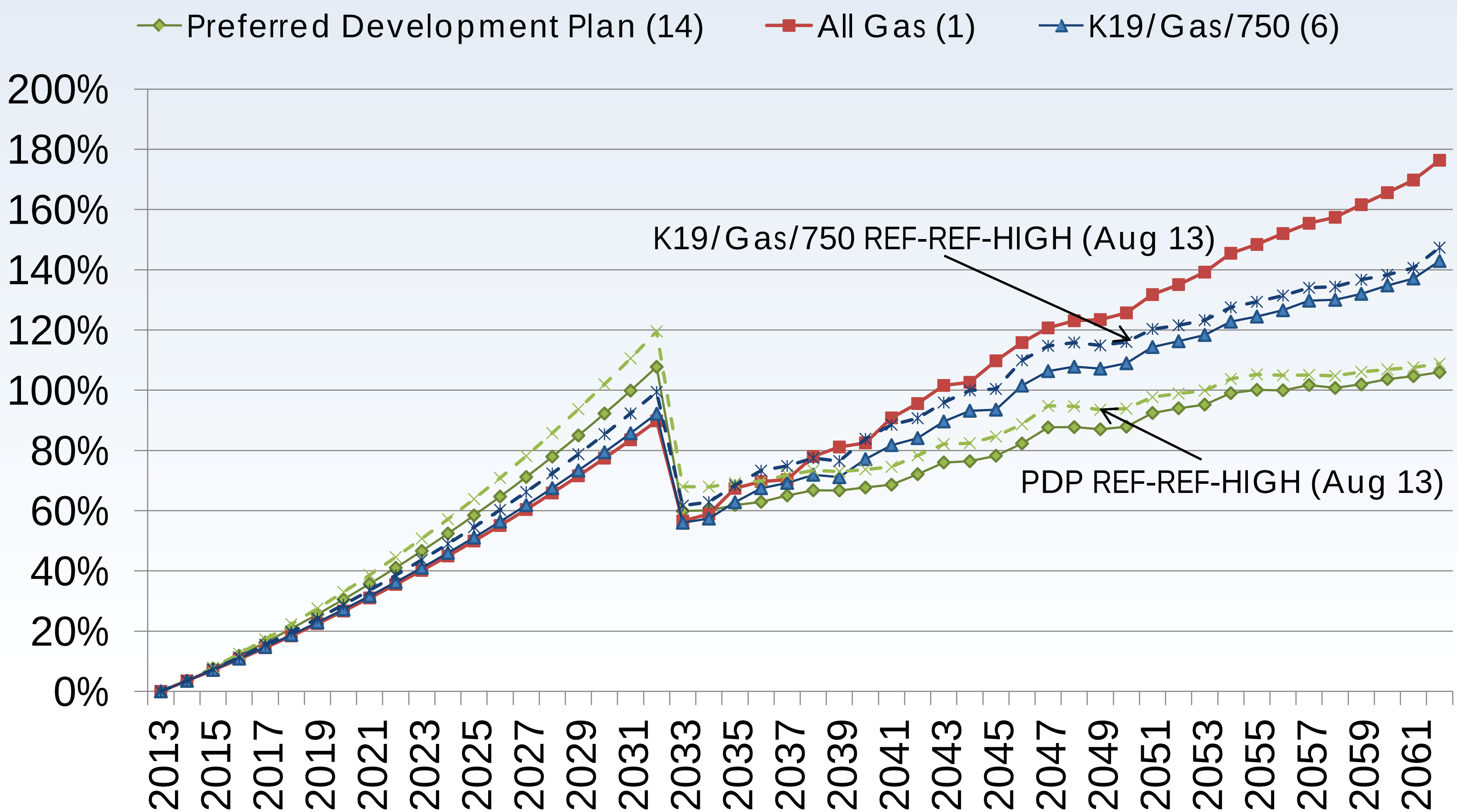
Cumulative Rate Increases (Nominal) Reference Scenario

263



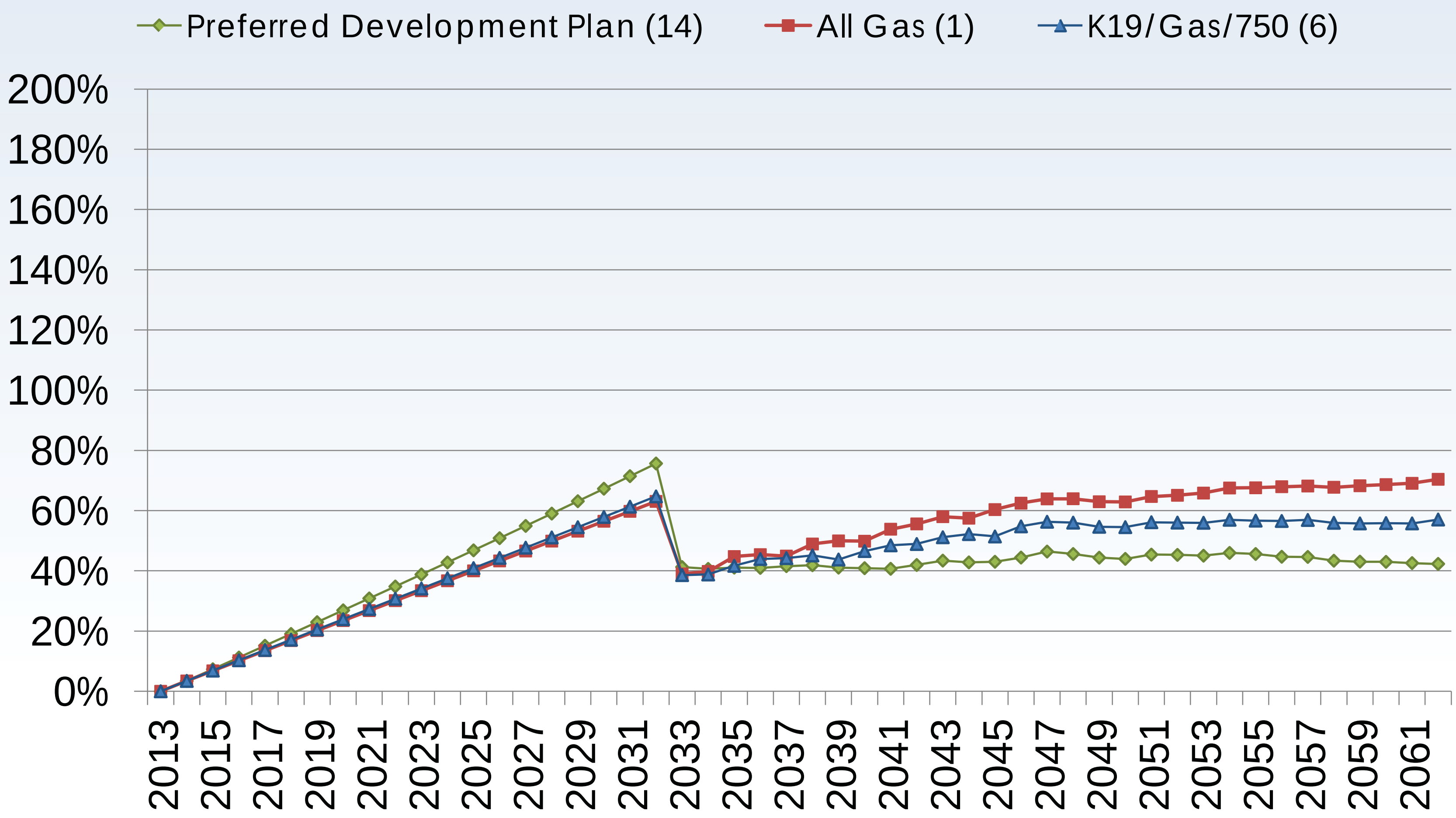
Cumulative Rate Increases (Nominal) Reference Scenario

264



Cumulative Rate Increases (Real 2013 = 100) Reference Scenario

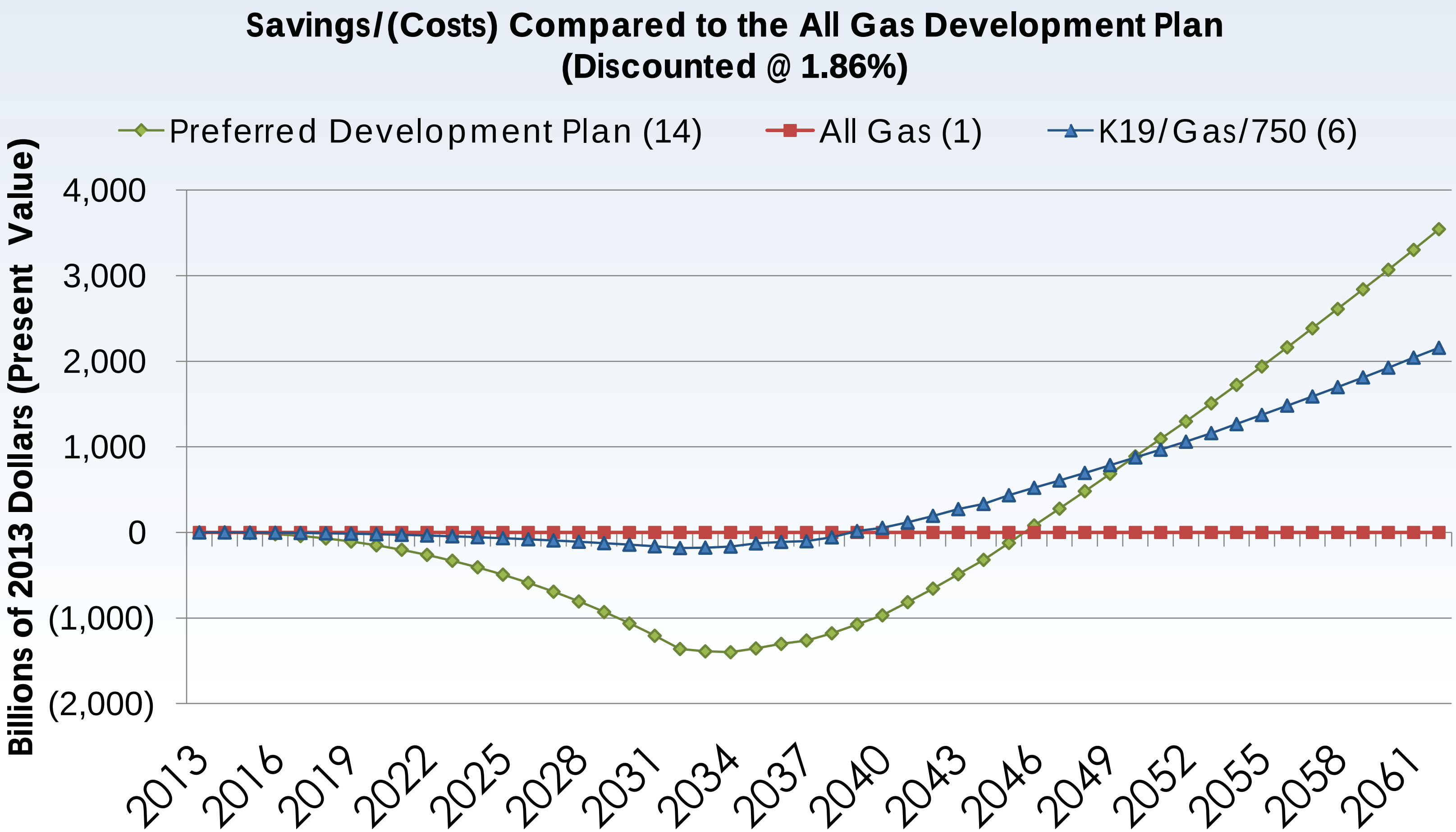
265



Cumulative PV of Consumers Revenue

- Based on economic theory, discounted at the social time preference rate
- Addresses the relative patience or impatience for consumption and intergenerational equity
- 1.86% calculated based on projected real return on short term Canadian T-Bill, not adjusted for income taxes
- Reflects Manitoba Hydro's investment in province's public infrastructure – long-lived assets of 100 years or more
- Does not reflect WACC
  - Cost of Corporate debt and equity reflected in the consumers revenue
- Does not reflect high investment threshold for the private sector represented by cost of capital – this is in the economic analysis

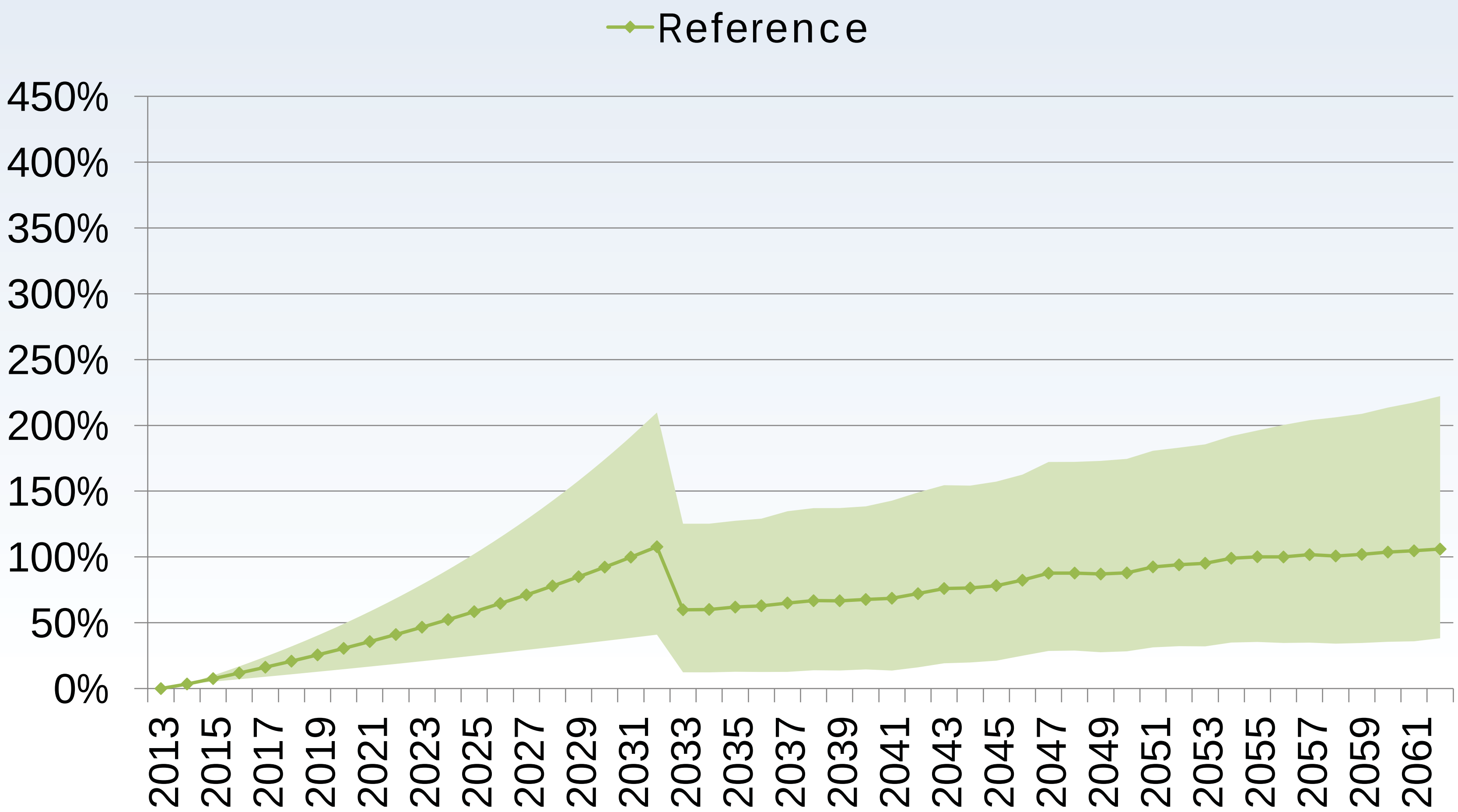
Cumulative PV of Consumers Revenue Reference Scenario



Uncertainty Analysis

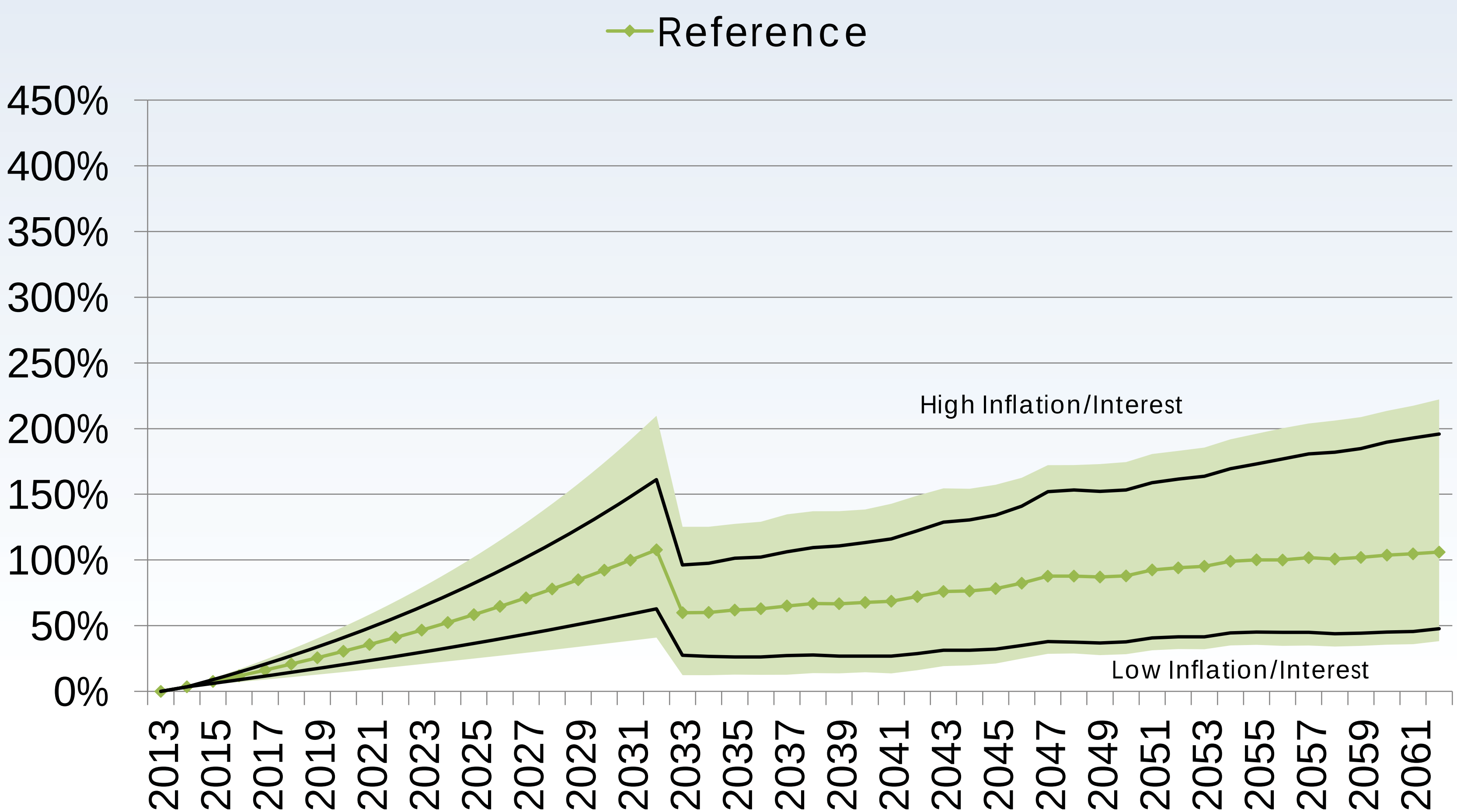
Cumulative Rate Increases (Nominal) Preferred Development Plan (14)

269



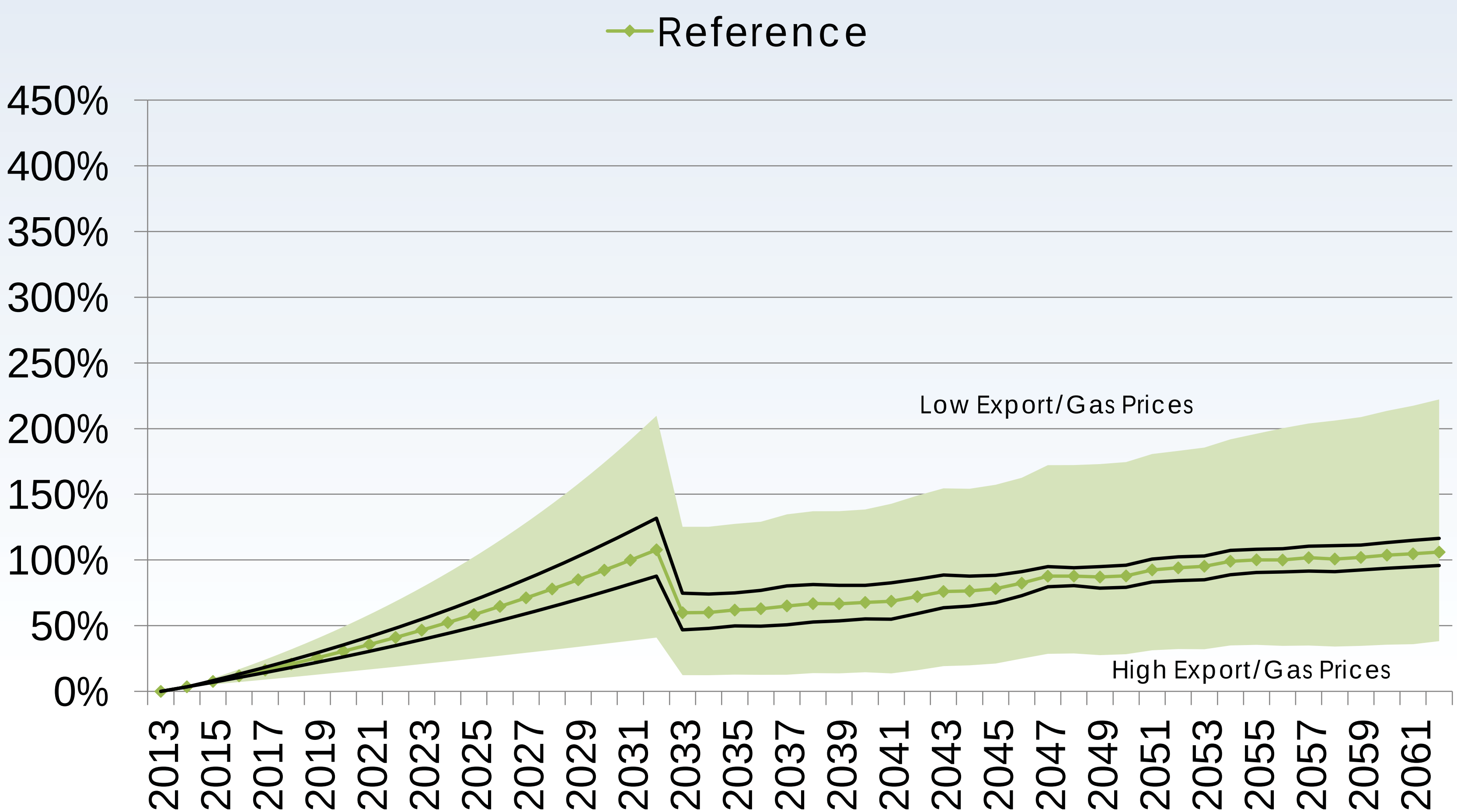
Cumulative Rate Increases (Nominal) Preferred Development Plan (14)

270

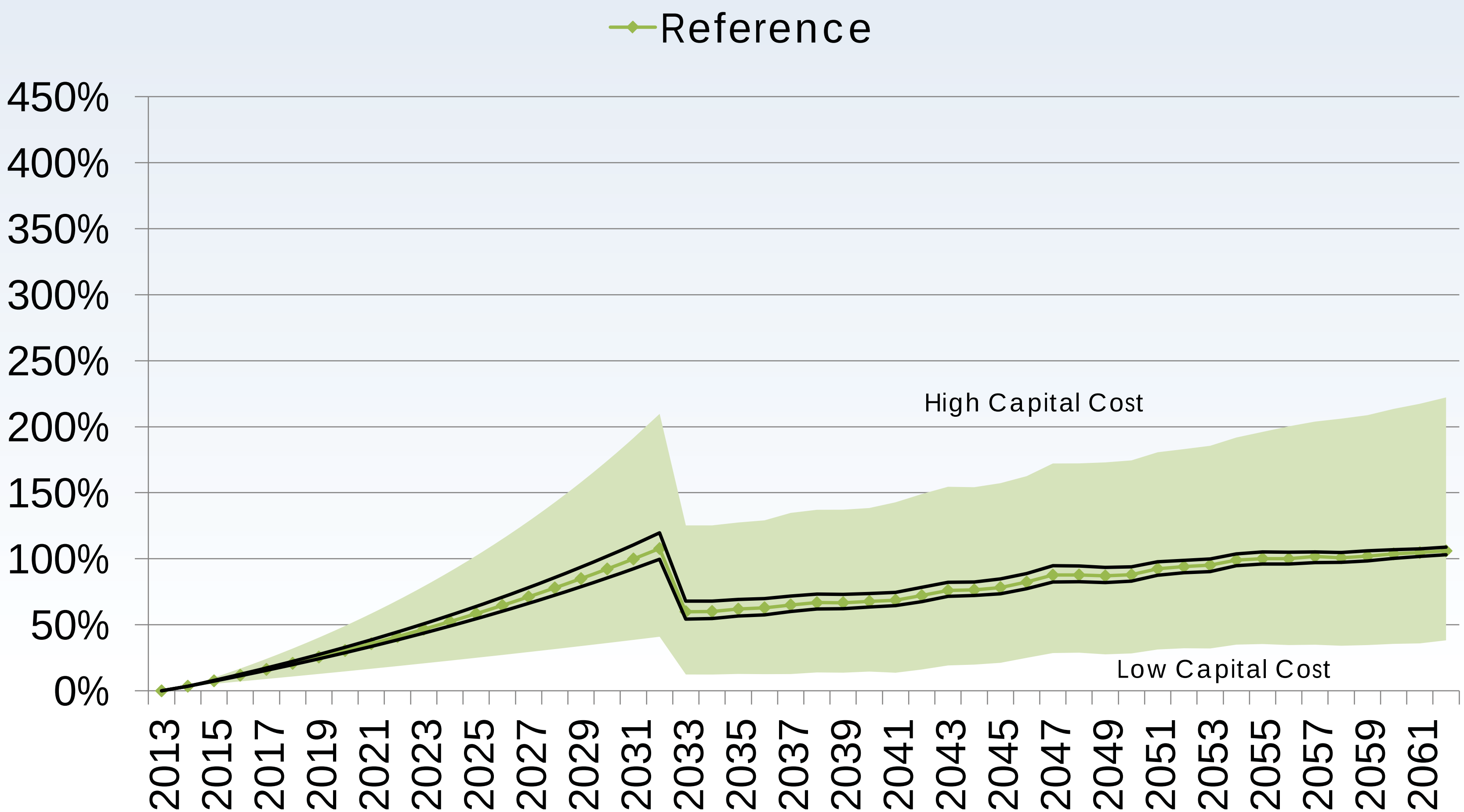


Cumulative Rate Increases (Nominal) Preferred Development Plan (14)

271



Cumulative Rate Increases (Nominal) Preferred Development Plan (14)



Customer Rates Summary

- Rate increases above the rate of inflation are required under all scenarios due to investments in existing infrastructure and reliability and reductions in non-firm export prices compared to those of a few years ago.

- Rate increases in the period to 2032 are moderately higher under the PDP than All Gas and Keeyask/Gas/750.

- Under the reference scenario, the PDP rates are lower than All Gas and Keeyask/Gas/750 by 2035.

- On a present value basis, the PDP consumers revenue is lower than All Gas by 2046 and lower than Keeyask/Gas/750 by 2050.

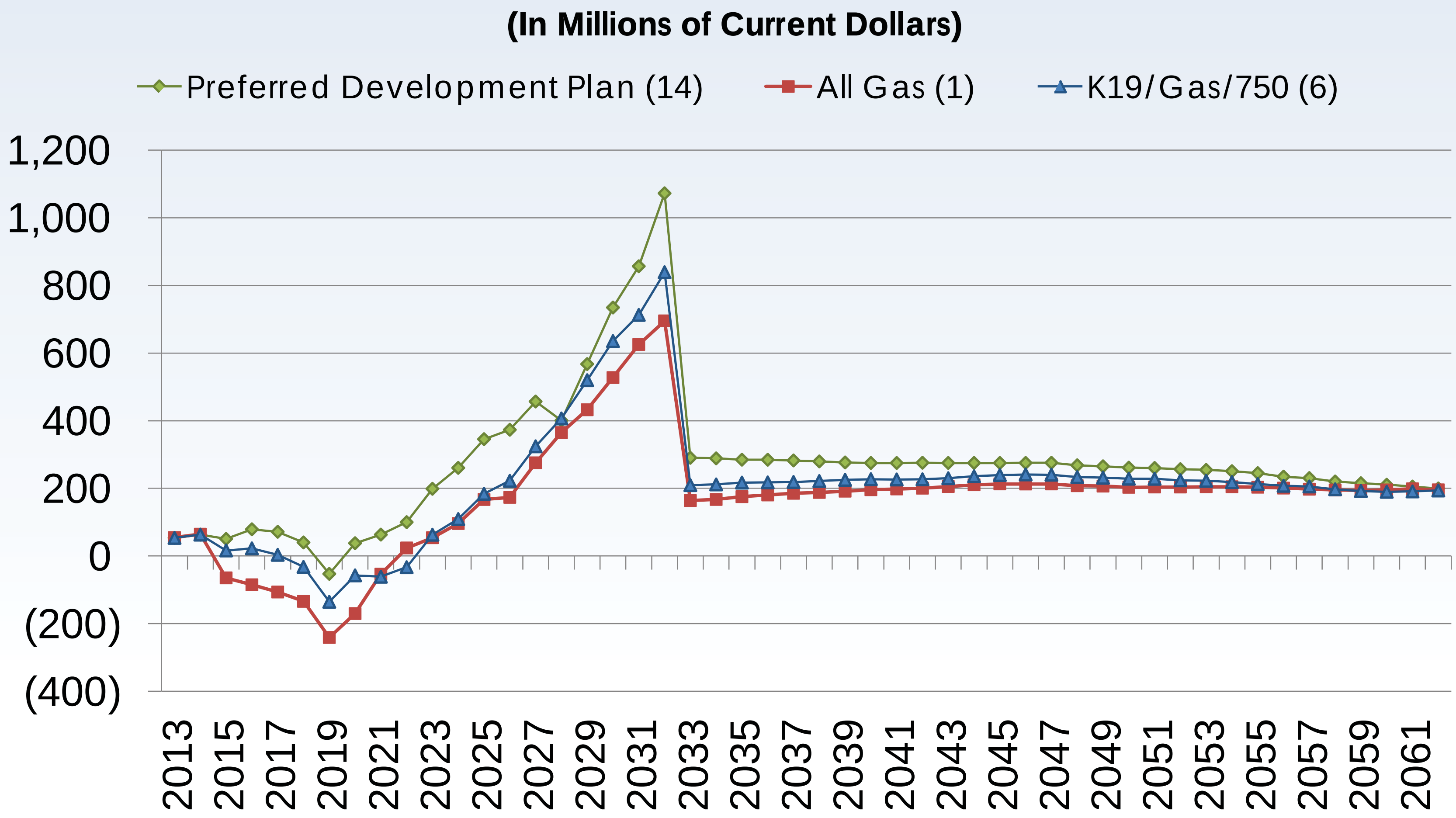
- Costs of the Preferred Development Plan do not directly affect Manitoba Hydro's electricity rates today.
  - Costs are deferred until in-service at which time they are included in net income and revenue requirement and amortized over the lives of the associated assets.

- Once in operation, the Preferred Development Plan is anticipated to assist in maintaining affordable and competitive Manitoba Hydro rates.
  - Costs are spread over a very long time matching when customers receive the benefits,
  - Carrying costs decline over time, and
  - Exports offset costs passed on to ratepayers.

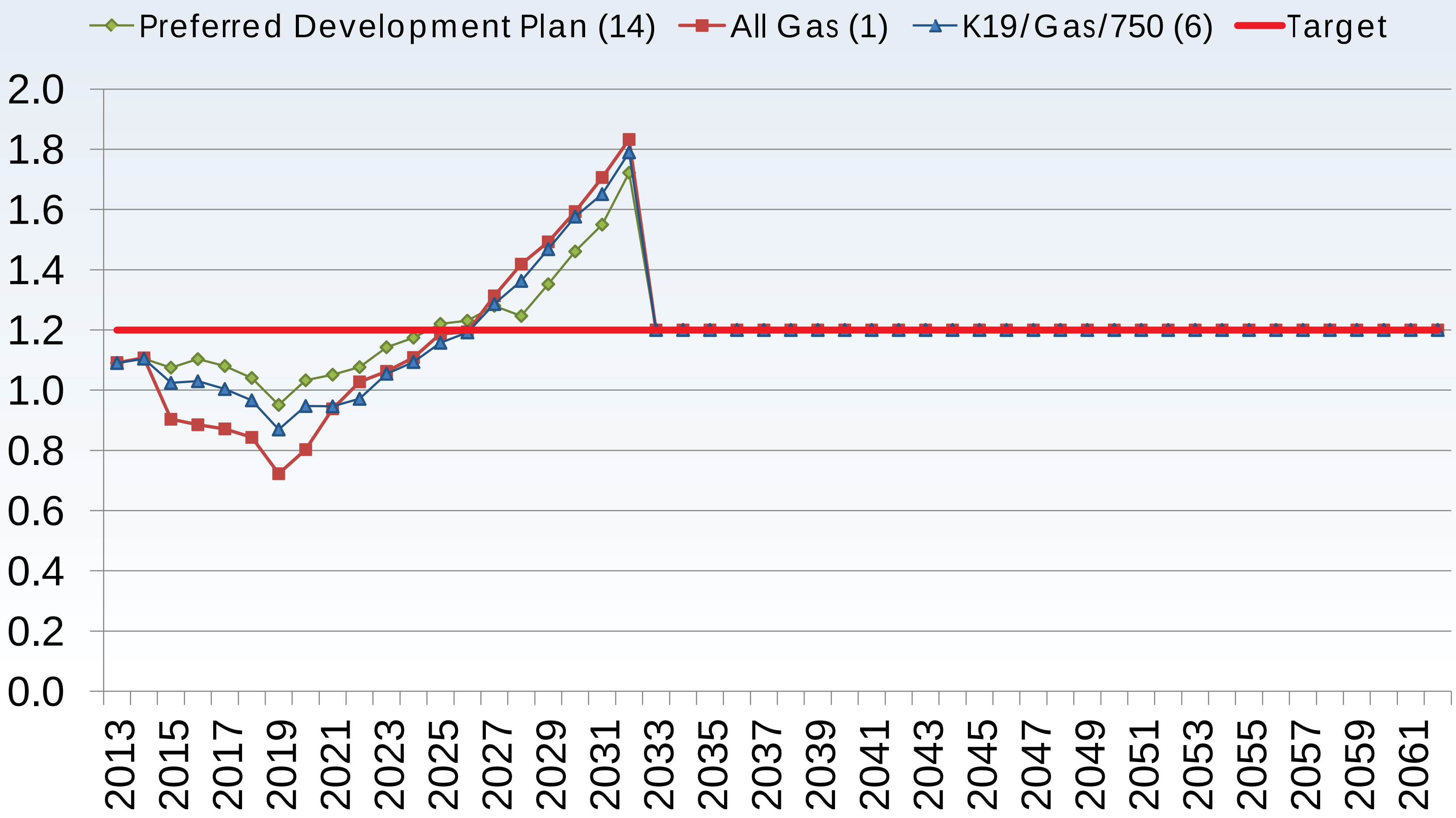
NFAT Financial and Rate Analysis

Impact on Manitoba Hydro's Financial Position

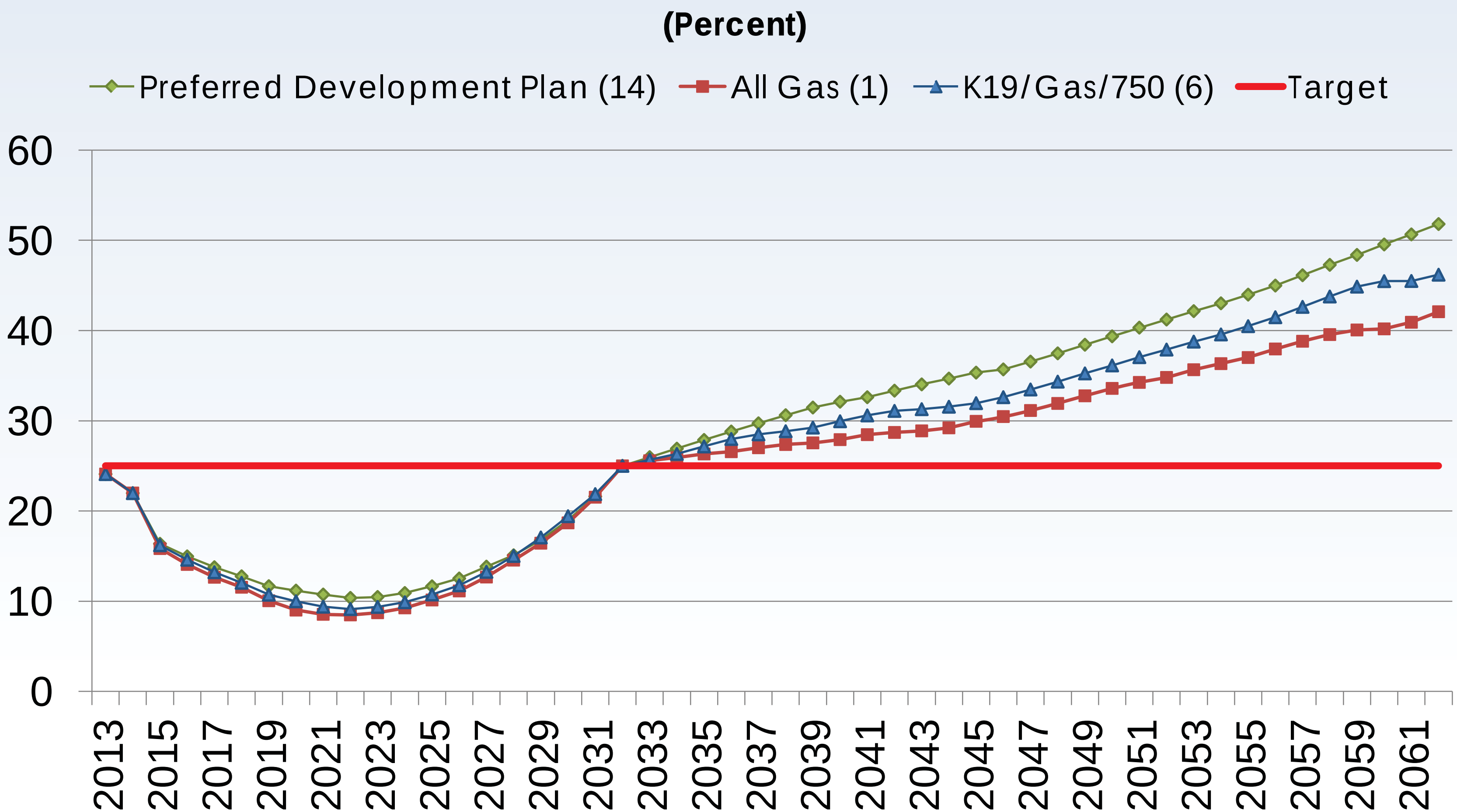
Net Income
Reference Scenario



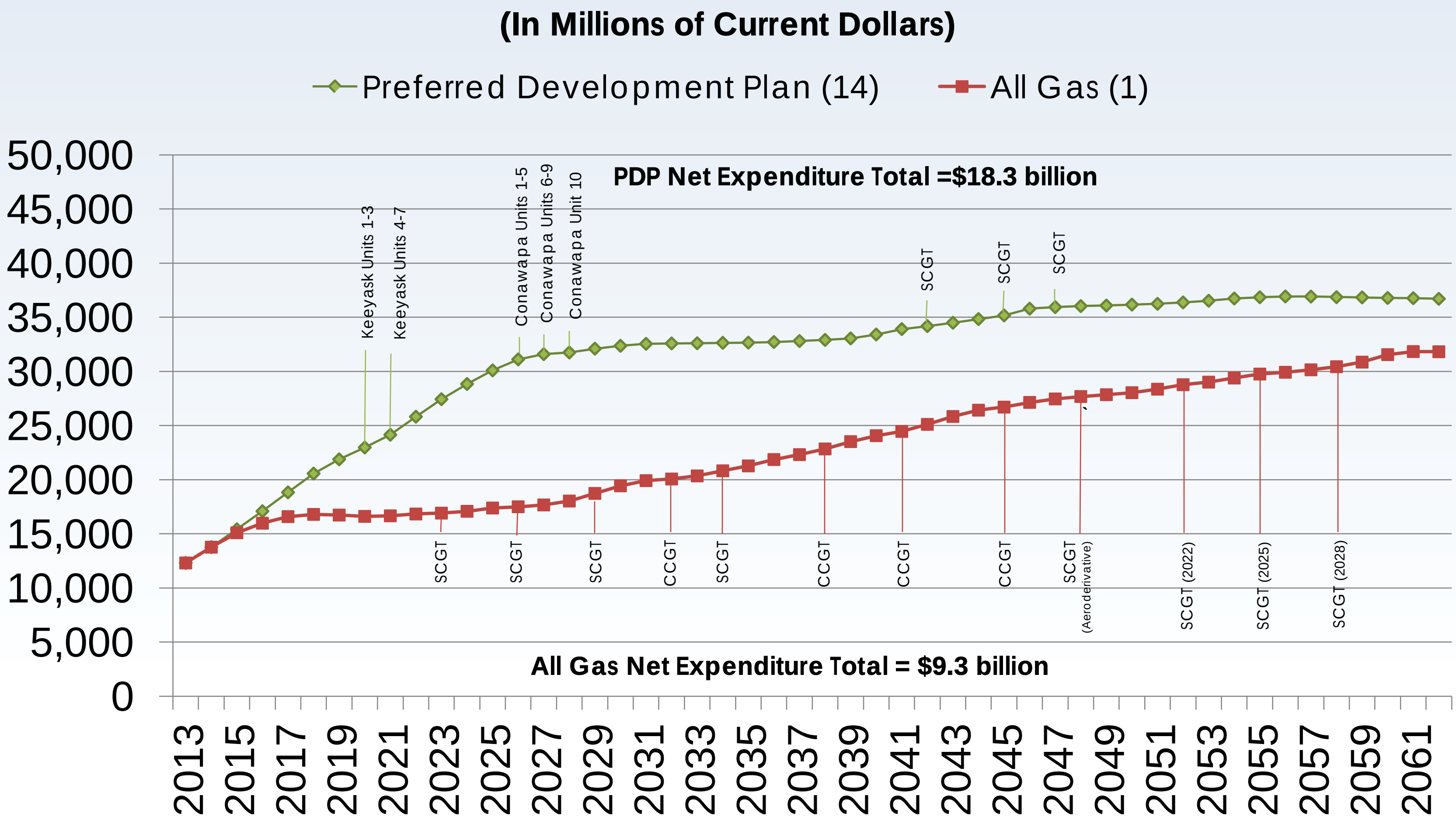
Interest Coverage Ratio
Reference Scenario



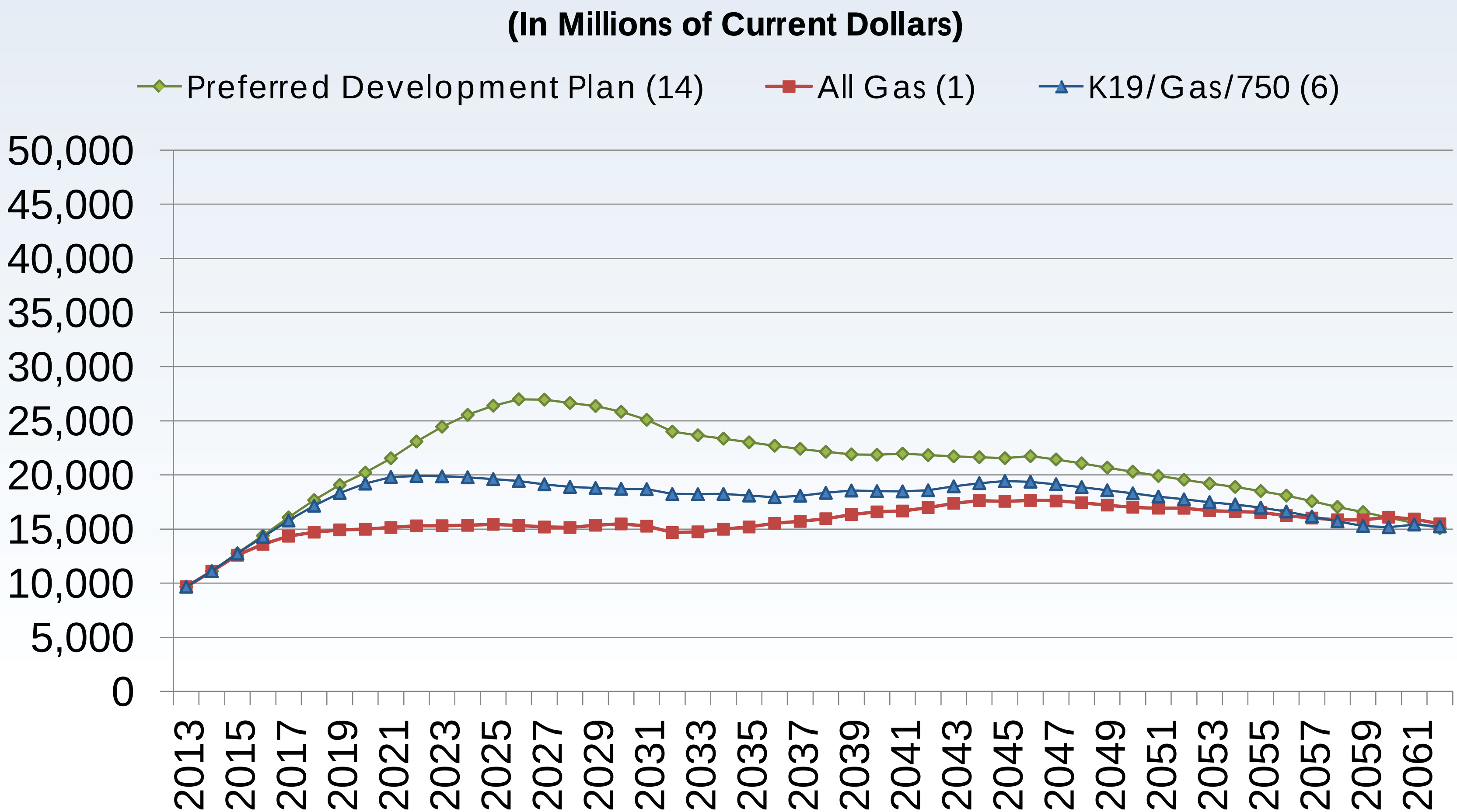
Equity Ratio
Reference Scenario



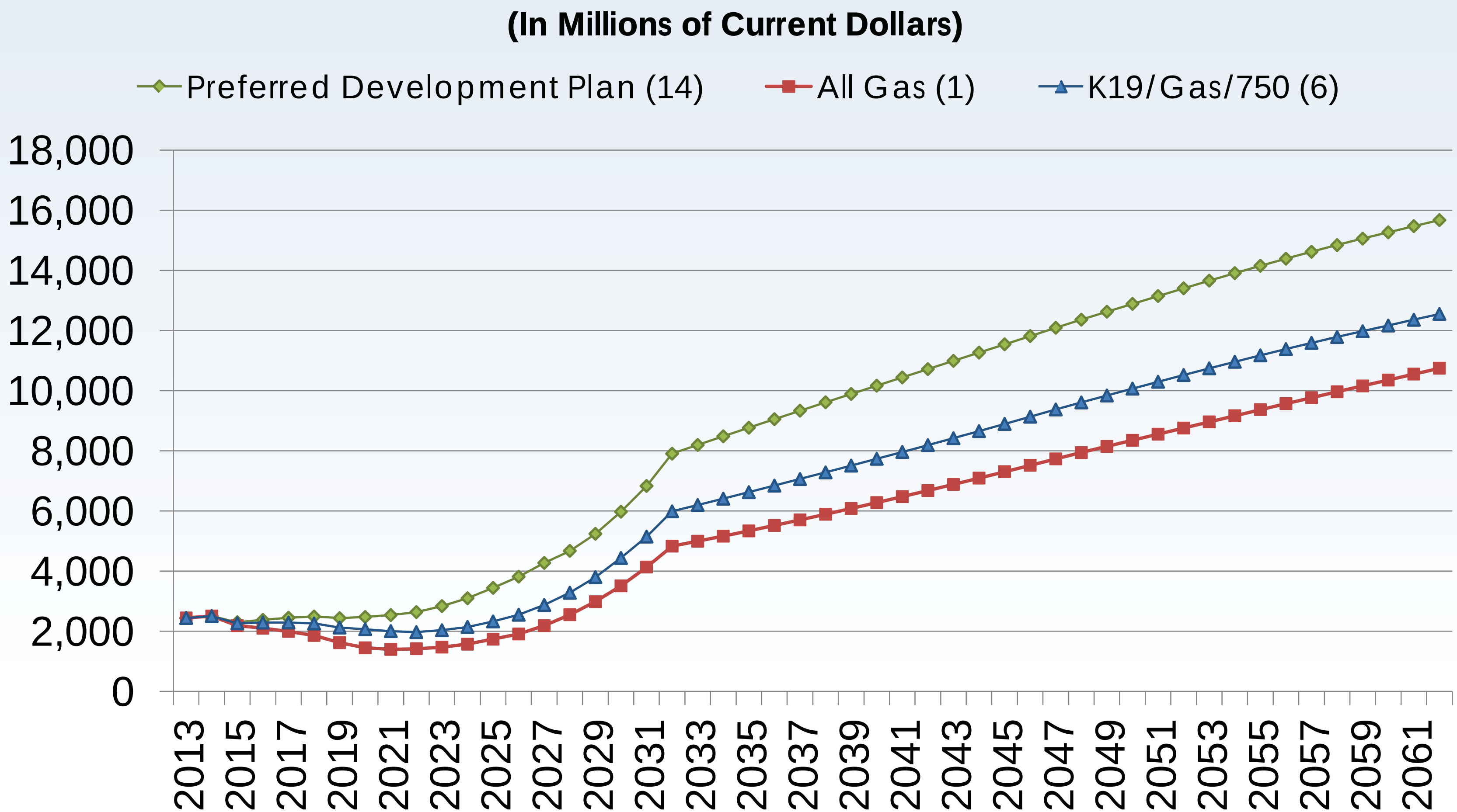
Assets (PP&E and Construction in Progress) Reference Scenario



Debt (Net of Sinking Fund and Investments) Reference Scenario



Retained Earnings Reference Scenario



Financial Risk Management

Risk Management is Integral to the NFAT Submission

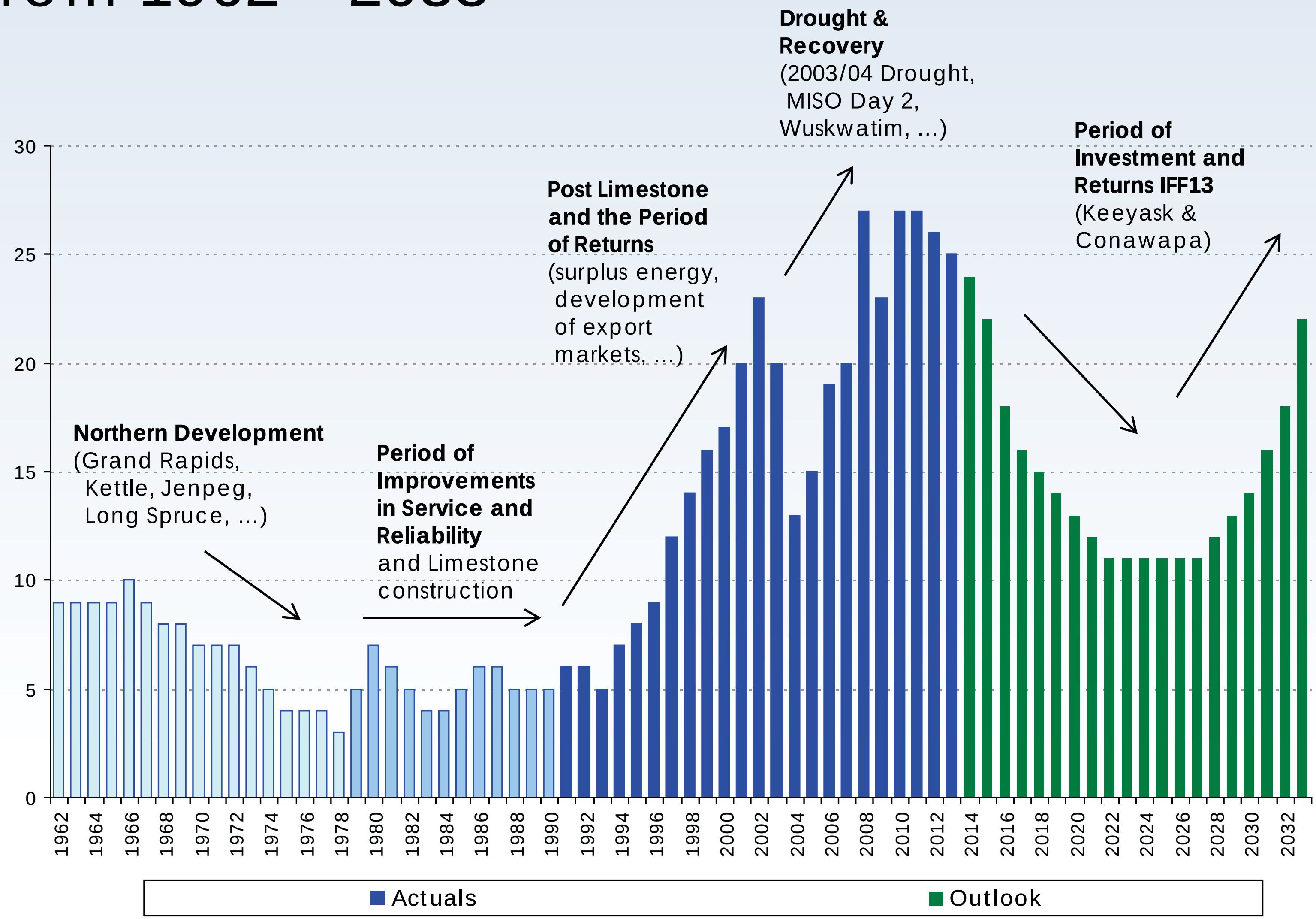
- Manitoba Hydro considers **business risk as an integral aspect of its plans and operations**.
- Manitoba Hydro's financial risks, forecasts, ratios and evaluations have been extensively examined (eg. Chapter 11 and Appendix 11.4 with 216 distinct sets of pro-forma financial statements).
- The financial volatility of severe drought was also examined in the NFAT filing (eg. Section 11.4).
- The submission also includes flexible pathways to manage through future uncertainties.

Financial Risk is Manageable and Debt Self-Supporting

- Manitoba Hydro is embarking upon its development plans from a position of strength.
- As measured by the equity ratio, the Corporation is well situated to move forward with its upcoming capital investments.

Manitoba Hydro's Equity Ratio from 1962 – 2033

284



Financial Risk is Manageable and Debt Self-Supporting

- With respect to Manitoba Hydro’s borrowings, the Corporation receives a flow through credit from the Province of Manitoba.
- In exchange for this flow through borrowing capability, Manitoba Hydro pays a provincial debt guarantee fee to the Province of Manitoba.
- As Manitoba Hydro makes interest and principal payments to bondholders on an uninterrupted basis, the debt is considered by the credit rating agencies to be self-supporting.
- Therefore, to the extent that Manitoba Hydro prudently manages its debt and maintains its self-supporting status, Manitoba Hydro’s capital investment plans should have no significant impact on the Province of Manitoba’s credit rating.

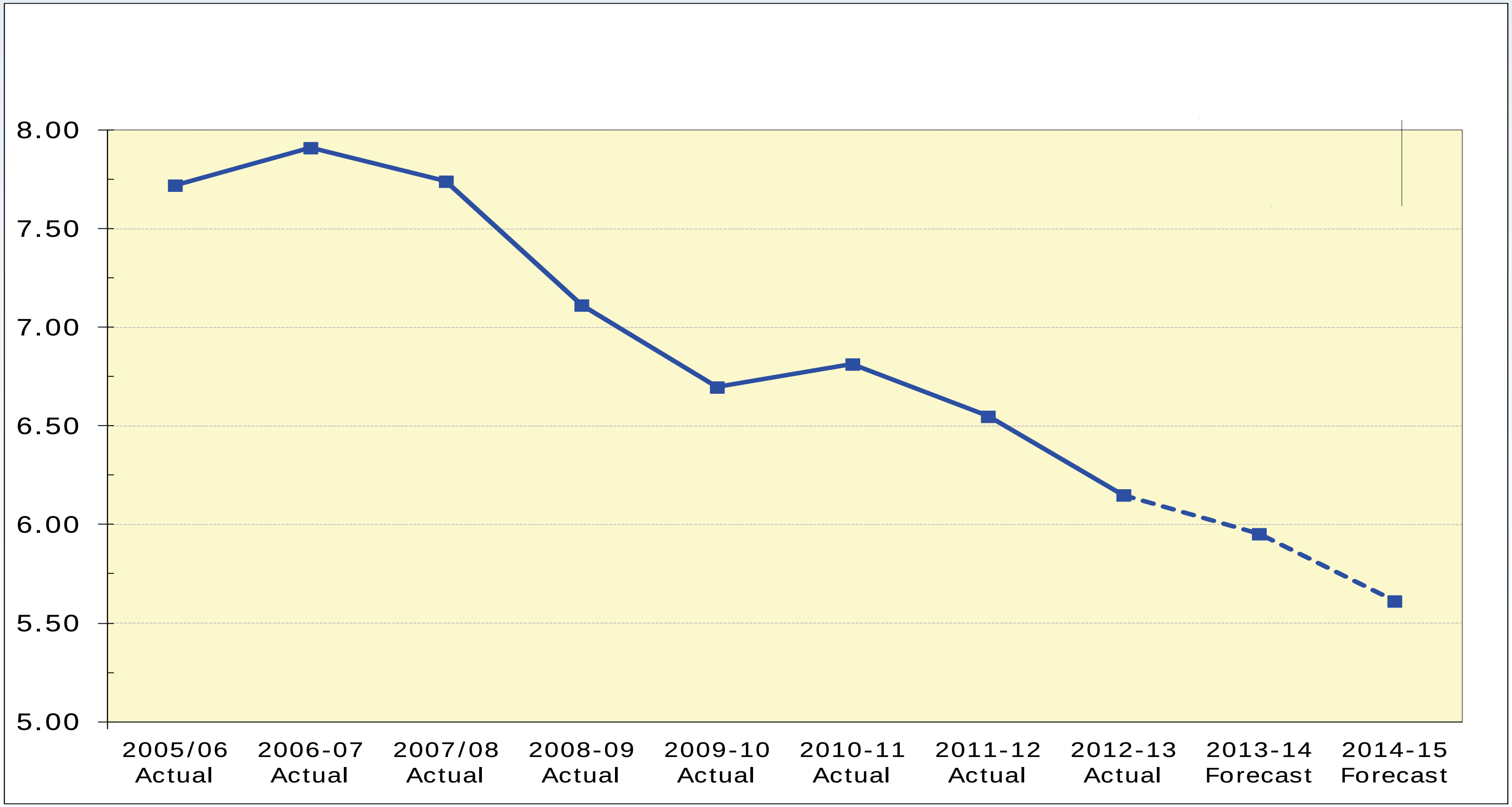
Debt Management Strategy

- Manitoba Hydro's fundamental debt management objective is to provide stable, low cost funding to meet the financial obligations and liquidity needs of the Corporation.

- Manitoba Hydro's actual long term financing includes debt issuance in various terms to maturity.

- In order to mitigate refinancing risk, Manitoba Hydro will:
  - Match long-lived assets with long term debt, and
  - Continue to favour long term fixed rate financings with maturities of 10 years+.

Debt Management Strategy – Low Cost



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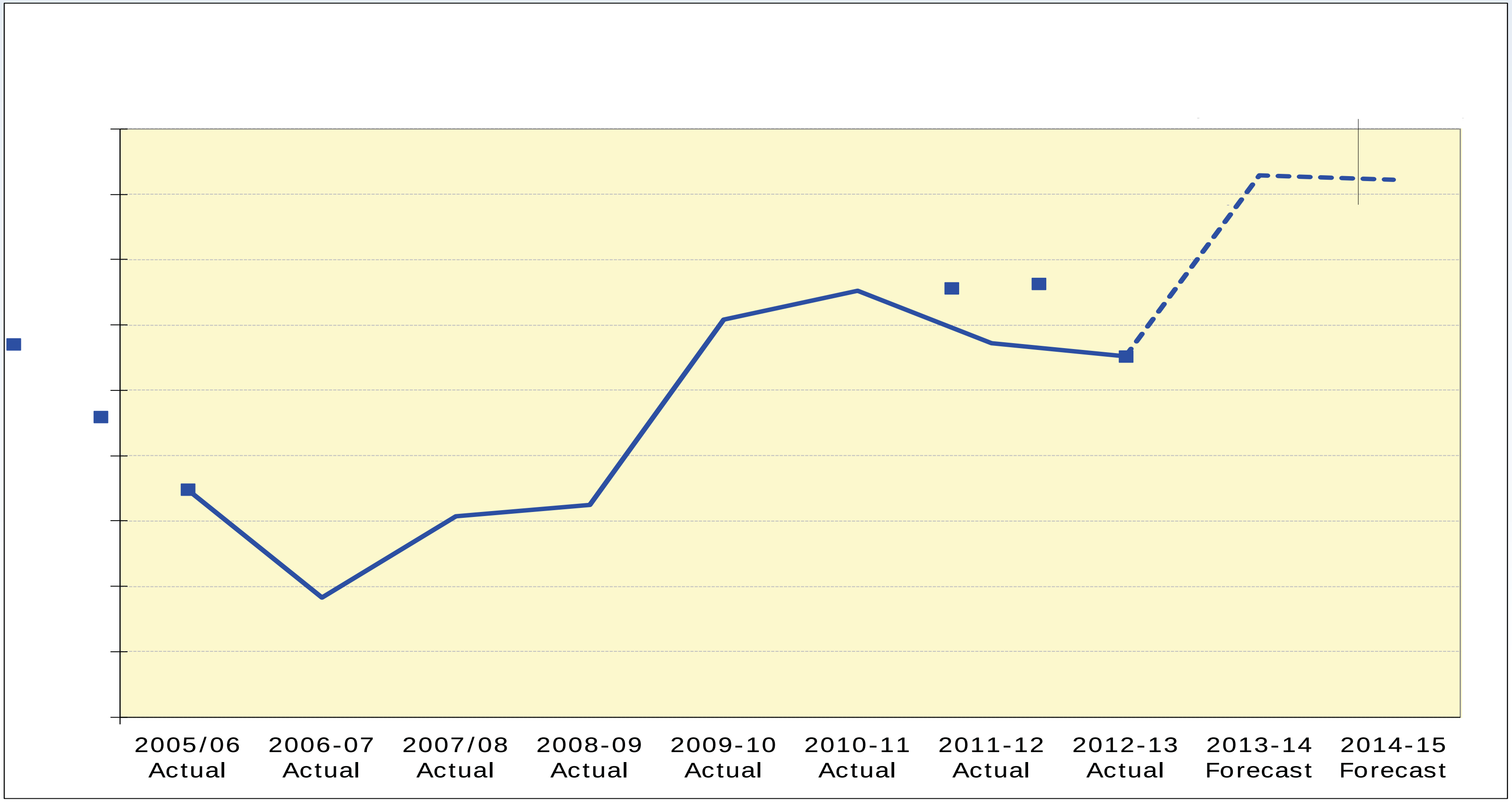
Debt Management Strategy – Stability



Foreign Currency Exchange Risk

- Manitoba Hydro's net income is largely inoculated from fluctuations in the movement of the USD/CAD exchange rate.
- Manitoba Hydro has significant export revenues and cash inflows denominated in US dollars.
- However, in order to manage the currency exchange risk on these revenues, Manitoba Hydro maintains a natural hedge with offsetting US dollar cash outflows, including finance expense on US denominated debt.

Liquidity Risk

- Liquidity risk refers to the risk that Manitoba Hydro will not have sufficient cash or cash equivalents to meet its financial obligations as they come due.
- Manitoba Hydro will meet its financial obligations when due through cash generated from operations, short term borrowings, long term borrowings, and where applicable, sinking fund withdrawals.
- Manitoba Hydro can issue short term borrowings in the name of the Manitoba Hydro-Electric Board up to a limit of $500 million.

Liquidity Risk

- During a severe prolonged drought Manitoba Hydro would provide sufficient cash flows for the continuity of business operations and Manitoba Hydro's self-supporting status.
- Liquidity measures include:

1. Cash conservation. Manitoba Hydro would curtail or delay operating and capital expenditures as required and appropriate. In severe circumstances, this may include exercising the optionality available within the development plan pathways.
2. Bridge financing. Manitoba Hydro could draw upon its $500 million short term borrowing program and/or access the capital markets for shorter dated debt financings that could be retired upon the resumption of positive cash flow from operations.
3. Increase cash inflows through rate increases. Should circumstances warrant, Manitoba Hydro could apply for higher rate increases in order to generate additional cash inflows.

View from the Credit Rating Agencies

(2) **Low-cost hydro-based generation.** Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened future capital expenditure requirements.

From the **Dominion Bond Rating Service (DBRS)** credit rating report on the Manitoba Hydro-Electric Board dated September 16, 2013; page 2 (highlighting added). For the full report see PUB/MH I-85(b), Attachment 1]

View from the Credit Rating Agencies

Significant Borrowing for Manitoba Hydro, but Self-Supported

Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting. This Crown Corporation's ability to meet its own financial obligations without recourse to provincial subsidies is a positive credit attribute for the province. In our view, the likelihood that the contingent liability represented by Manitoba Hydro's debt would materialize remains relatively remote.

[From the **Moody's** Investors Service credit rating report on the Province of Manitoba dated July 23, 2013; page 3 (highlighting added). For the full report, see PUB/MH I-85(b), Attachment 4].

View from the Credit Rating Agencies

FINANCIAL TARGETS TO BE CHALLENGED BY HIGHER CAPEX

As part of its debt management strategy, Manitoba Hydro targets certain financial metrics such as an interest coverage ratio greater than 1.2 and equity-to-capitalization greater than 25%. With new generation and transmission projects underway, such as Bipole III, Keeyask and Conawapa, total capital expenditures are forecasted to be $20.7 billion, or on average $2 billion per year from FY2014 to FY2023. About one third of the total planned capex will be funded by internally generated cash from operations, leaving the rest to debt financing. New debt financing will ramp up in FY2014 and peak in FY2018 and FY2022, at an annual average of approximately $1.7 billion. Given the uptick in capex and corresponding debt, financial metrics are predicted to fall below targets in the next three fiscal years. The equity ratio, in particular, will be challenged and not likely to return to target until FY2032. The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays, given the nature of a hydroelectric plant's long construction cycle before cash generating begins. However, we view Manitoba Hydro as being capable of prudently managing debt and mitigating such risks by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation.

[From the **Moody's** Investors Service credit rating report on the Manitoba Hydro-Electric Board dated September 23, 2013; page 2 (highlighting added). For the full report, see PUB/MH I-85(b), Attachment 3].

Financial Risk Summary

1. Manitoba Hydro considers business risk as an integral aspect of its plans and operations.

2. Manitoba Hydro's financial risk is manageable.

3. Manitoba Hydro will continue to take appropriate actions to ensure its debt remains self-supporting.

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

NEEDS FOR AND ALTERNATIVES TO

REVIEW OF MANITOBA HYDRO'S

PREFERRED DEVELOPMENT PLAN

Regis Gosselin - Chairperson

Marilyn Kapitany - Board Member

Larry Soldier - Board Member

Richard Bel - Board Member

Hugh Grant - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

March 19, 2014

Pages 2709 to 2980

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--- Upon commencing at 8:59 a.m.

THE CHAIRPERSON: Good morning. I believe it's nine o'clock, so we'll get started right away. Unusual not to have Mr. Wojczynski directly in front of us, so we'll have to develop some questions to make sure he comes back to us.

So good morning. I'd like to advise that there were no undertakings filed during the CSI session. And I wonder if there are any undertakings to file now before we start?

MS. MARLA BOYD: Nothing to file in the way of undertakings. I do have a couple of exhibits to record. We did send electronically yesterday the additional CV for Mr. Greg Barnlund, which I believe will be Exhibit 92-4.

--- EXHIBIT NO. MH-92-4: Additional CV for Mr. Greg Barnlund

MS. MARLA BOYD: And we also could mark the financial panel direct evidence presentation this morning if you'd care to do that now. Can you give me a number?

(BRIEF PAUSE)

MS. MARLA BOYD: Well, it's on its way to you, Mr. Chair. I believe it'll be Exhibit number 111.

--- EXHIBIT NO. MH-111: Financial panel direct evidence presentation

MS. MARLA BOYD: So by way of introduction, this is a fresh face of panel members for you. To my immediate left is Mr. Darren Rainkie, who's the vice president of Finance and Regulatory. To his left is Ms. Liz Carriere, who's the manager of Financial Planning. Then we have Mr. Manny Schulz, corporate treasurer, and Mr. Greg Barnlund, who's the division manager of Rates and Regulatory Affairs.

Seated behind them and providing witness support, you know Ms. Fernandes and Ms. Ramage, of course. And then we have Mr. Greg Epp, who is the senior financial analyst of the Major Project Section. Then Mr. Rick Horocholyn, sorry, who's the senior financial analyst. Susan Stephen is the Financial Markets department manager. And Louella Harms -- Ms. Louella Harms is the supervisor of Retail Electric

Rates.

And if the panel could be sworn, we could begin with direct evidence.

MANITOBA HYDRO PANEL 5:

GREG BARNLUND, Sworn

LIZ CARRIERE, Sworn

DARREN RAINKIE, Sworn

MANFRED SCHULZ, Sworn

THE CHAIRPERSON: On behalf of the panel, good morning to all of you. Some familiar faces and we're happy to see you back, and some new faces so that's always refreshing. Thank you.

MS. MARLA BOYD: Thank you, Mr. Chair.

EXAMINATION-IN-CHIEF BY MS. MARLA BOYD:

MS. MARLA BOYD: Mr. Rainkie, could you please outline your experience and qualifications, as well as your role in the NFAT filing, please?

MR. DARREN RAINKIE: Certainly. Good morning, Mr. Chairman, members of the Board, Intervenors, and ladies and gentlemen. My name is Darren Rainkie, and I'm the vice president of Finance and Regulatory at Manitoba Hydro. I'm a chartered accountant, chartered business evaluator, and have a bachelor of commerce honours degree from the University of Manitoba.

I have been with Manitoba Hydro and Centra Gas for over nineteen (19) years. Prior to my current position, I held various management and financial positions, including manager of Regulatory Services, corporate treasurer, and corporate controller. I was appointed vice president of Finance and Regulatory in January of 2013, and have overall responsibility for the controllership, treasury, rates and regulatory, financial planning, corporate risk management, and subsidiary functions at Manitoba Hydro.

In my testimony, I will provide evidence on policy matters as they relate to the financial and rates material contained in the NFAT filing.

MS. MARLA BOYD: Ms. Carriere, could you please outline your experience and qualifications, as well as your role in the NFAT submission, please?

MS. LIZ CARRIERE: Good morning, Mr. Chair, Board members, Intervenors, and -- and counsel and -- and advisors, and others in the room. My name is Liz Carriere. I'm the manager of Financial Planning in the Finance and Regulatory Business Unit.

I have -- I'm a certified general

accountant, and I have a bachelor of commerce honours degree from the University of Manitoba. I've been with Manitoba Hydro for twenty-four (24) years, eighteen (18) of those within the Financial Planning Department. So eighteen (18) -- I've had a hand in at least eighteen (18) IFFs over the years.

I've also provided regulatory support to numerous regulatory proceedings, as well as I am responsible for preparing the financial projections for the -- the First Nation partnerships that we have on the major projects.

My role here in the NFAT proceeding is to provide evidence on the NFAT financial evaluation, specifically the rate impacts and the impacts on Manitoba Hydro's financial position. Thank you.

MS. MARLA BOYD: Thank you, Ms. Carriere. Mr. Schulz, could you outline your experience and qualifications, and your role in the NFAT submission, please?

MR. MANFRED SCHULZ: Certainly. Good morning, Mr. Chairman, members of the Board, Intervenors, and others present. My name is Manny Schulz, and I've held the position of corporate treasurer since 2008. Prior to accepting this role, I joined Manitoba Hydro in 2006 as the corporate controller.

Previous senior work experience includes being the vice president of Finance and Business Development at Dow BioProducts from 2004 to 2006. I was the director of business consulting group at Grant Thornton LLP from 2000 to 2003. And I was the chief operating and financial officer for GBR Architects from 1994 to 1999.

In terms of my academic qualifications, they include being the direct -- the bachelor of environmental studies degree from the Faculty of Architecture in 1981; an MBA in 1988, also from the University of Manitoba. In 1995 I received the certified management accounting designation. And in 2009 I was awarded the fellowship in the FCMA designation.

I will be providing testimony on credit ratings, debt management, including the financial risks associated with interest rates, foreign currency exchange, and liquidity. Thank you.

MS. MARLA BOYD: Thank you, Mr. Schulz. Mr. Barnlund, could you outline your experience and qualifications, and your role in the submission, please?

MR. GREG BARNLUND: Certainly. Good

morning, Mr. Chairman, members of the Board, Intervenors, and others present. My name is Greg Barnlund, and I'm the division manager of Rates and Regulatory Affairs in the Finance and Regulatory Business Unit.

I'm a certified engineering technologist and graduated from Red River Community College with a diploma in mechanical engineering technology in 1988. I've been with Manitoba Hydro and Centra Gas Manitoba for twenty-five (25) years.

I was appointed to the position of division manager Rates and Regulatory Affairs in June of 2013. My responsibilities include overseeing the preparation of regulatory filings and applications for submission to the Public Utilities Board of Manitoba and the National Energy Board, the preparation of rates and cost of service studies for both electric and natural gas operations, and the preparation and administration of business investment policy for electric operations.

I've testified before the Public Utilities Board on several occasions, and have also appeared before the National Energy Board and the Federal Competition Tribunal. I've testified to matters related to natural gas cost allocation, rate design, terms of service, service extension policy, western transportation service, and the competitive landscape for natural gas sales in Manitoba.

Most recently, I testified to rate and regulatory matters at Centra's 2013 general rate application, and although I've provided regulatory support to several of Manitoba Hydro's electric applications, this is my first opportunity to testify to electric matters before this Board.

For this proceeding I'll provide evidence related to the impacts on domestic electricity rates and the comparative situation with electricity rates in other jurisdictions.

MS. MARLA BOYD: Thank you, Mr. Barnlund. Mr. Chair, you have before you and on the monitor the Manitoba Hydro Exhibit 111, which is the PowerPoint presentation for the direct evidence of this panel, and we're ready to commence if -- if you're ready.

MR. DARREN RAINKIE: Good morning, Mr. Chairman and members of the Board. I -- I will be up first in the presentation. So if we can move to slide 2 of the presentation, I will just give you a quick overview of how we've divided the material. We've put it into about five (5) different segments.

In the first two (2) segments of the presentation, I'll provide context on the financial and rate discussions that will follow my presentation by taking a few minutes to summarize Manitoba Hydro's current financial profile and provide a brief update on our financial outlook as contained in IFF13, recognizing that there are panel -- PUB panel members that have not had the benefit of sitting through an electric GRA, and that we have just recently filed IFF13 with the PUB.

In -- that's the first two (2) segments of the presentation. In the third segment, Mr. Barnlund will take over and provide an overview that demonstrates the competitiveness and affordability of Manitoba Hydro's electric rates now and in the future. In the fourth segment, Ms. Carriere will do the heavy lifting and provide a summary of the very extensive financial and rate analysis that was provided as part of the NFAT filing in support of the Preferred Development Plan.

Finally, in the fifth segment, Mr. Schulz will bat clean-up and will add the perspectives on risk by outlining how we manage financial risks at Manitoba Hydro, and discuss credit rating agencies and how they view Manitoba Hydro's debt as being self-supporting.

By all means stop us at any point if you have questions of -- of the content, or clarification. Certainly designed the presentation to inform the Board and help them, assist them go through this huge volumes of material that you have before you now.

So if we can move to slide 4, we'll chat a bit about Manitoba Hydro's consolidated income statement. So just a couple of things I want to point out. I won't go through all this material, obviously, but currently, our domestic electricity revenues at approved rates are around $1.4 billion. Export revenues have been in the 300 to $400 million range in the last four (4) years, which is down from the $600 million level that we experienced in 2009, mainly as a result of lower non-firm export prices.

Costs are generally increasing as a result of accounting changes to expense more and capitalize less overhead costs, general escalation, and inflation, and as well, there are higher financing costs, depreciation, and taxes associated with a growing asset base, including the in-service of the Wuskwatim generating station during 2012.

Lower net export revenues and higher costs have reduced the level of net income in the last two (2) years to below a hundred million dollars, which, in turn, has resulted in lower interest coverage ratios. I'll -- I'll cover off our financial ratios later in the presentation, so. And I will talk a bit about our current financial year a little bit in the -- later in the presentation as well. This was presented more for historical context.

Just quickly moving then to slide number 5 and the consolidated balance sheet. I think it's fair to say that Manitoba Hydro is primarily a fixed-assets company. We have property, plant, and equipment and in construction in progress of over $18.8 billion, that's at historic cost, as of December 31st, which is our most recent public financial statements -- December 31st of 2013.

So that results in net property, plant, equipment, and construction progress of $13.3 billion net of accumulated depreciation currently. So that's just to give you an idea of the size of our current balance sheet.

The assets are financed primarily by $10.2 billion of long-term debt net of sinking fund assets and $2.6 billion of retained earnings as at December 31st, 2013. On a net basis, the amount of working capital that we have is fairly negligible. We are really a fixed assets company.

It's interesting to compare the current balance sheet back to 1990, which I've put on the far right side of the slide, before the first unit of the Limestone generating station came into service almost twenty-five (25) years ago.

In 1990, Manitoba Hydro had $3.9 billion of net fixed assets and was largely financed by $3.6 billion of net long-term debt and just $117 million of retained earnings. In 1990, the debt-to-equity ratio was 95:5, which means that the Corporation was financed with 95 percent debt.

Fast-forwarding today and moving to the left side of the -- of the slide, Manitoba Hydro's assets and debt are approximately three (3) times what they were back in 1990. And with the retained earnings of 2.6 billion, we currently have a debt-to-equity ratio of 76:24, meaning that 24 percent of our assets are financed by retained earnings. And Manitoba Hydro is in the strongest financial position in its history, its long history.

While it's human nature to view -- view the large investments that are required under any potential plan in the future with concern, the history of this public utility shows that it is but one (1) phase in a continuing cycle of investment and reinvestment in fixed assets in order to ensure safe and reliable service to Manitobans.

Much like the growth over the last twenty-five (25) years, the Preferred Development Plan is expected to result at a balance sheet as roughly two point five (2.5) times the size of the current balance sheet over the next twenty (20) years.

And then if we could move to the next slide, slide number 6 in the deck, spend a couple seconds on our cashflow statement; not to leave Mr. Schulz out of the equation because he certainly is concerned about our cashflow.

So you'll note that in the last number of years we've generated about $600 million of cashflow from operations, which is under the caption, "Cash provided by operating activity," so -- on the slide.

In the last few years, we've also had investing activities, which is primarily investment and fixed assets, at the 1.2 to $1.3 billion level, which has resulted in net financing activities in the order of 6 to $700 million in the last two (2) years.

The level of investing and financing activities are expected to ramp up significantly due to the planned investments in Bipole III, Keeyask, and

Conawapa, and you'll see that in our financial forecast, IFF13.

The capital coverage ratio has been lower in recent years compared to historic levels due to the increased requirements for sustaining or what we refer to as our base capital expenditures, which are necessary in order to maintain the health of our existing assets.

And then just moving quickly to slide number 7. What I've done is pulled out our electric operations out of our third quarter financial report ending December 31st, 2013. So our financial statements have the electricity segment, which includes our regulated operations plus our subsidiary operations.

And what you see here is simply the regulated operations year over year for the nine (9) months ended December 2013, versus the nine (9) months ended December 2012. And you can see that our financial results have improved considerably over that time frame for two (2) primary reasons: first, higher domestic electric revenues as a result of rate increases granted by the Public Utilities Board in colder weather; and, secondly, higher net extraprovincial revenues as favourable water flow conditions and higher export prices.

The outlook to the end of the 2013 fiscal year ended March 31st, 2014, in IFF13 is for electric operations net income of 116 million and consolidated net income of 136 million.

And if we move to slide 8. This is an interesting slide because it shows the relative proportion of revenues over the last ten (10) fiscal -- completed ten (10) fiscal years that have been derived from residential, industrial, commercial, and export customers.

It breaks down roughly 28 percent of the revenue has come from residential customers, 40 percent has come from industrial and commercial customers, and 32 percent from export revenues. We'll talk a bit more about this later in the presentation.

And then just moving to slide 9 and just summing up a couple key points about our existing financial profile. As I mentioned, with retained earnings of $2.6 billion, Manitoba Hydro is in the strongest financial position in its history, and this positions the Company well to make the necessary investments in the future to meet the energy needs of the province, which is our mandate.

The export revenues associated with

Manitoba Hydro's predominantly hydro system has certainly been a key contributor to the Corporation's financial strength and affordable rates for customers.

So I went through that rather quickly, but certainly, as I said, stop me if there's anything that comes to mind as you -- as you go along. I'm just the context piece at the front end here, so I want to leave some time for Ms. Carriere to go through the -- the analysis that's before you.

So if there's no questions, maybe we'll move onto the second segment, which is a -- a quick update on our financial outlook as contained in IFF13, Integrated Financial Forec -- Forecast '13. So slide 11 just gives you a real brief high-level view of some of the major changes between our current forecast, IFF13, that was just approved by our Board on February 26th of 2014, versus the previous forecast, IFF12, that was approved by our Board in November of 2012, and was the -- the base, if you like, for the NFAT filing at that point in time.

So key -- key changes, the load forecast is lower due to lower forecasted population growth. I think there's probably already been discussion about that at the hearing on the first panels. The Conawapa in-service date was deferred one (1) year to two (2) --

to the 2026 -- twenty (20) -- sorry, '26/'27 fiscal year. There was increased capital costs of $1.6 billion due to the Conawapa deferral, the reinstatement of DSM costs into the capital forecast, and the effect of updating a number of project estimates, and adding in some new projects.

The electric export price forecast for 2013, for on-pipe -- on-peak prices decreased on average by 3 percent over the period from 2014/'15 to 2032/'33. That's compared to IFF12. And I -- I think if you recall, the adjusted IFF12 that was used in the NFAT filing had export prices that were about 10 percent lower than -- than what was in IFF12, so the 3 percent reduction is actually 7 percent higher than what was included in the NFAT filing, and I hope that's clear.

Other major change is the International Financial Reporting's Standards implementation has been deferred by one (1) year to 2015/'16, and we have assumed in the IFF13 that rate-regulated accounting will continue over the forecast period, and both of these assumptions have been included in IFF13 as a result of recent pronouncements of the Account -- Accounting Standards Board of Canada and the International Accounting Standards Board.

And recognizing the financial outlook, we have forecast further con -- constrainment on operating cost growth to 1 percent growth between 2016 and 2021.

So those are the major highlights of -- of IFF13, and what you would have seen in the IFF12 in the last electric general rate application filing.

Slide number 12 is a rather busy slide, but I would ask you just to -- to focus on the -- the second row from the bottom, which looks at the total change in net income -- consolidated income between IFF12 and IFF13. So we -- we've already talked about the key drivers between the improved results for 2013/'14, and we see that the consolidated net income is expected to be $63 million better than the previous forecast.

For 2014/'15, after updating all the factors, revenues, and costs, there really isn't much change in the -- in the forecast. It's really just a $4 million differential. Quite a significant deterioration in 2015/'16, primarily related to the lower load forecast of $66 million. And if you go to the far right, over the whole twenty (20) year period to 2032/'33, our net income is expected to be $2.5 billion lower than what was included in IFF12 as a result of the lower load forecast and the higher capital expenditures.

Then moving to slide number 13, is a graphical depiction of the expected pattern of consolidated net income over the next twenty (20) years, and also compares the differential between IFF13 and IFF12. So as you can see, net income is expected to be thin in the next ten (10) years, even with the 3.95 percent projected rate increases, primarily due to the capital expenditures that are required to renew aging infrastructure and provide reliability of the electrical system such as Bipole III.

This will be further challenged when the in-service of the Keeyask generating station comes into service, but net income is expected to rebound sharply after the in-service of the Conawapa generating station.

And, of course, on slide 14, following closely after net income is retained earnings. You can see in the forecast that initially retained earnings are expected to be higher in IFF13 than they were in IFF12, given the assumption that Manitoba Hydro will no longer have to write off about $300 million of rate regulated assets in 2014/'15, as had been the assumption in IFF12. In the later years of the forecast -- oh, sorry -- sorry, Liz. In the later years of the forecast retained earnings are fore -- are forecast to be lower than in IFF13 for the aforemention -- aforementioned reasons.

And if we move to slide 15, you'll hear a lot about our financial targets in the -- in the next number of days, so I thought it would be useful just to spend a couple of minutes reiterating what they are. We have three (3) primary financial targets in Manitoba Hydro. First, a -- a debt-to-equity target. We strive to maintain a minimum debt-to-equity ratio of 75:25, which means that we would like to have 25 percent of our assets funded through internally generated funds rather than through debt.

Our second financial target is -- is interest coverage. We'd like to maintain a interest coverage ratio of greater than one point two-zero (1.20), so we want to have a cushion of significant issue -- of sufficient earnings to cover interest payments, and that's why we set the ratio at the one point two-zero (1.20).

The third key financial target we have at Manitoba Hydro is the capital coverage. We'd like to maintain capital coverage ratio of greater than one point two-zero (1.20), and that is to have a cushion to have sufficient cash flow to cover our base capital expenditures.

Then if we then follow on to slide 16 and go through the projected ratios in IFF13, first the equity ratio for that -- that is projected over the next twenty (20) year period. So, much like the retained earnings slide, the equity ratio in IFF13 is initially higher due to the assumption of no rate regulated asset write off and further aggressive operating cost constraint.

And while the trajectory level is off a bit compared to IFF12, there is a similar pattern after the in-service of the Cona -- Conawapa generating station, such of that we are able to meet the 25 percent equity ratio target by 2034, which is just one (1) year outside of the twenty (20) year forecast period.

Go to the next slide. This is number 17. This depicts the interest coverage ratio forecast for the next thirty (30) -- for the next twenty (20) years rather, and I won't spend a lot of time on this in the next slide, but suffice to say that the interest coverage ratio and the capital coverage ratio exhibits the same general pattern as the equity ratio.

They weaken during the period of

reinvestment in assets and the investment of new generation, and then interest -- the interest coverage ratio recovers to target levels post-Conawapa in-service. And if we move to the next slide, the capital coverage ratio, the -- the same pattern, but the capital coverage ratio is projected to recover to target levels post-Keeyask in-service.

And moving to slide 19. I listened with great interest to the exchange between Mr. Hacault and Mr. Thomson on day 1 of the hearing with respect to who contributes to the retained earnings of the Company that are required to meet financial reserve requirements.

Slide 19 is interesting in that it demonstrates the high degree of correlation between the level of net extraprovincial revenues and net -- and the level of net income on both a historic and forecast basis. From this slide, one could argue that it is the export customers that have and will continue to assist in building reserves that keep Manitoba electricity customer rates amongst the lowest in North America.

And then on slide 20, just a summary of -- of our financial outlook and some of the key points. There's no doubt that the required investments and existing infrastructure and new generation will put pressure on Manitoba Hydro's financial ratios in the next twenty (20) -- in the next ten (10) years and that higher than 3.95 percent rate increases would be required to maintain those ratios at their target levels over that period. But is that -- that is not what we're projecting will happen. We -- we will maintain 3.95 percent rate increases in the next ten (10) years.

In setting financial targets in the first place, it's always been recognized that the targets may not be obtained during periods of major investment in a generation and transmission system and that ratios will necessary -- necessarily weaken during those periods of investment.

Credit-rating agencies and other stakeholders are prepared to accept short-term weaknesses in financial ratios due to the investments in revenue-generating assets as long as Manitoba Hydro can demonstrate stready -- steady progress towards those targets over the long-term.

A supportive regulatory climate is also important to credit-rating agencies who recognize the capacity to raise rates, given the low rate structure that Manitobans enjoy. It is important, and continues to be important, that Manitoba Hydro have regular and reasonable rate increases during the reinvestment and new investment period to maintain progress towards financial targets.

The good news is the financial ratios are expected to recover after the in-service dates of the Keeyask and Conawapa generating station and reach target levels within a forecast horizon of around twenty (20) years. After that period, pressures on rates is forecast to subside.

Export revenues will continue to play an important role in improving the Corporation's financial strength and keeping Manitoba electricity rates low in the future.

Mr. Chairman, thanks for the opportunity to address the panel. Subject to any questions that you may have of me, I would hand it over to Mr. Barnlund to address the competitiveness and affordability of Manitoba Hydro's electricity rates.

MS. MARILYN KAPITANY: Mr. Rainkie, could you just go back to slide 19 for a minute, please --

MR. DARREN RAINKIE: Sure.

MS. MARILYN KAPITANY: -- where you had talked about the extraprovincial revenues and the net income.

Could you go through that explanation once more?

MR. DARREN RAINKIE: Sure. So what -- what is depicted on this chart is the relationship between net extraprovincial revenue, which is extraprovincial revenue minus water rentals and assessments and fuel and power purchases, and -- and net income.

So there was some discussion at the front end of the hearing about, you know, who -- who has contributed to the reserves that assist in keeping our balance sheet healthy, which is there on behalf of customers to ensure rate stability in the future.

So I find this chart very informative to look back over time and ask ourselves how -- how did we -- how did we improve our financial position over the last twenty-five (25) years. And when you look at the high degree of correlation between net income and extraprovincial revenues, you see how important is has been in attaining the financial strength that we have today and indeed in keeping rates low for Manitobans.

So one could look at this very simplistically as our improvements in reserves levels over time have been contributed by export customers such that Manitoba customers, both residential, commercial, and industrial, have only had to pay the costs associated with -- with our system.

Now, as far as I'm concerned, contributions to revenue requirement is -- is appro -- is a cost as well. It's something that customers have to put forward. We don't have return requirements like private companies that require a 10 or 11 percent return on equity. We probably on average only have about a 3 percent contribution based on a calculation of our net assets.

But -- so -- so I -- I think that it's appropriate that we recover both costs and a contribution to reserves from our customers. This is simply the observation that if you map that relationship out between these two (2) factors, that you could argue that export customers hep contribute the reserves, which -- which is important in -- in terms of improving our financial position and helps us make the next required investment. That -- that was what I was trying to point out.

THE CHAIRPERSON: Just a point of clarification, Mr. Rainkie. The -- the IFF13 figures you're giving here, have they been adjusted to address the DSM -- increased DSM that we've been hearing about?

MR. DARREN RAINKIE: No, Mr. Chairman.

what it's saying is that hydro-based developments are going to have large capital outlays and it's probably going to drive up rates more significantly in the next ten (10) years than other plans would. And I think the Preferred Development Plan probably has the highest rates by 2023.

And then it's saying that if we make these initial heavy capital outlays, which is going to require some rate increases to do it, it has the promise in, you know, the distance future, out twenty (20) years or so, of lower rate increases.

And so it's -- I mean, I don't object to this one quite so much, but it's -- I think it's putting clearly the choice between us that we -- we know Hydro has large capital outlays, it has the promise down the road of lower increases, but we need some higher ones immediately to finance it, versus other forms of investment, which may have a different profile for rate increase changes.

MR. GREG BARNLUND: Definitely -- I mean, the scenario is that hydro facilities -- hydroelectric operations are very, very capital intensive with very, very low operating costs, and very long asset lives. So that's why the -- the graph represents the way it does.

MS. LIZ CARRIERE: Thank you, Mr. Chair. For the next about six (6) slides, I plan on flipping through them very quick -- quickly. They're on the financial evaluation assumptions and methodology, so if you'd require any clarification, please let me know.

In contrast with the economic analysis, which looks at the net benefit of each of the development plans over the project life, the financial evalua -- evaluation compares the year-by-year impacts of each of the development plans on Manitoba Hydro's projected financial statements and cust -- customer rates.

The projected financial statements that are -- can be found in Appendix 11.4 model the impacts over the entire electric operation, so not just each of the development plans, but it also includes the impacts of ongoing operations of our existing infrastructure.

We -- we start out in the evaluation with IFF12, and extended that over the fifty (50) year period, and then we modified it for known updated assumptions since IFF12 was approved, specifically the 2013 preliminary forecast of electricity export prices.

Now, as Darren mentioned, the preliminary forecast was significantly lower than the -

- the final forecast. We reduced from IFF12 about 10 percent rather than the 3 percent, so it's a little more conservative than the -- the final 2013 forecast. Based on that export price adjusted IFF12, we then modify the generation costs and transmission associated with each of the facilities included in -- in the development plans, and their -- and their respective timing for those facilities.

Moving to slide 34, the cap -- net capital expenditures for each of the development plans are reflected in the balance sheet in construction in progress until the in-service; and then once they're in service, then property plant and equipment.

Once they're in service, capital costs are reflected on the income statement in depreciation on a straight-line basis over these full lives of the assets. Hydro generation, depending on the component, will have a twenty (20) to a hundred and twenty-five (125) year life. The gas turbines we've assumed a thirty (30) year life, and transmission substations, thirty-five (35) years, and -- and transmission lines, fifty (50) years.

We then incorporate the flow-related production costs and revenues associated with the facilities for each of the development plan. Now, those are -- are the prod -- the net flow related production costs and revenues, as well as the base capital costs are the same costs and revenues that are -- are used in the economic evaluations.

Moving to the next slide. The only difference is that we convert those economic evaluation costs and revenues from real to nominal dollars. In Appendix 11.4, we -- we break down the general consumers revenue into two (2) categories. The first is the general consumers revenue at approved rates, so we take the load forecast and apply the PUB approved rates of the day.

Under each of the development plans, these -- the general consumers revenue at approved rates does not change from plan to plan. We then calculate annual borrowing requirements based on the cash flow, or surplus, or deficit for each of the development plans based on both the existing infrastructure and new -- and new generation, and transmission associated with each of the development plans. Annual finance expense is then calculated based on the existing debt -- debt portfolio, plus the projected annual borrowing requirements in each of the plans.

On the next page, the second component

of general consumers revenue, once we've determined depreciation, carrying costs, production costs and revenues, we then look at the revenue requirement, or the general consumers revenue additional, and it reflects the incremental revenue required to recover costs for both existing infrastructure and the Development Plan.

Hydro has a longstanding strategy of smoothing rates over a period of time in developing its rate proposals. Under the cost-of-service regulation, cost recovery is smoothed out over time by absorbing some of those costs into retained earnings on a temporary basis, if it's financially prudent to do so, allowing sufficient time for export revenue benefits to accrue.

Because we were evaluating eight (8) development plans under twenty-seven (27) scenarios, we needed to automate how we -- we set rates. So when we normally do a -- a financial model or financial run, you know, we -- we are able to kind of massage the rates and -- and look at it on a one (1) -- on a case-by-case basis, but because of the volume, we had to do it in a mechanical manner, and so we've set a -- a set of fixed parameters using the -- the financial targets as -- as those parameters. And in order to do -- we did that so that we would remove any of the judgment and subjectivity in setting the rates and being able to make fair comparisons between each of the development plans.

So over the first twenty (20) years, we set rates on an -- on an even-annual basis to achieve 75:25 by 2032, which, at the time, in IFF12, was the same time when we returned to the -- the debt ratio target of 75:25, so it was a similar approach in IFF12.

After 2032, we revert to maintaining interest coverage setting rates based on maintaining an interest coverage of one point two (1.2) times. If you -- if you reduce or set rates at that time, you tend to -- based on just lowering rates from that point forward, then you tend to get equity ratios that just -- just go kind of wild, so in order to maintain that comparability, we left -- we -- we've targeted the rates to one point two (1.2) times interest coverage.

However, in doing that, and you'll see this in the graphs later on, strictly adhering to those financial targets results in somewhat volatile rate increases in -- after the 2032 period. In practice, we would actually smooth those over time, but it's -- the real value is in seeing the -- the differential between the -- the development plans.

The rate increases, of course, because -- due to the uncertainty of forecasting, they're indicative and are showing the general directional trend in rates. Actual rate increases will vary from those, and will depend on many other factors, and -- and not just the choice of development plan due to changing water flows, weather, and costs to maintain the system, and economic variables. And of course, future rates will be subject to the review and approval before the Public Utilities Board.

Just a note on -- on development plans where -- where Keeyask or Conawapa is deferred, we are showing approximately 1.2 and .4 billion to be incurred to June 14 on Keeyask and Conawapa respectively. For the purposes of this evaluation, we made a simplifying assumption that we would expense all sunk costs over an eighteen (18) year amortization period. If we were not to receive approvals for Keeyask or Conawapa, or the Conaway -- or the Corporation deferred it for some other reason, costs would be -- that were -- would be deemed to no longer provide future benefit must be expensed.

In practice, Hydro would perianna -- periodically analyse the nature of those costs determined -- to determine that future benefit, and some costs would have a longer expecter future benefit than others. Others would be much shorter and would have to be written off sooner.

Now, the next figure -- figure is Figure 11.1 from Chapter 11. Now, admittedly, it's very busy and complicated, and provides a lot of information, so the -- the remainder of the slides, we've simplified them by reducing it down to three (3) plans, and the first -- the next section, the first several slides, we're going to focus on the reference scenario, and then we're going to take a look at some of the uncertainty around that reference scenario.

On slide 40, we have the Preferred Development Plan. In the early years to 2032, we can see rate increases of 3.95 percent. We see -- now, at -- because of the -- the rate setting methodology we use, we -- we see a bit of a correction factor after 2032, where we now switch to using the one twenty (120) interest coverage target to set rates. And -- and as I -- I said, in practice, these would much -- much more likely be smoothed over time rather than introduce such -- such significant changes in rates in any one (1) year.

The rates over the entire fifty (50) year period is about 1 1/2 percent if we were -- were to smooth them -- or calculate an equal annual rate over the entire fifty (50) year period.

In the -- in the period to 2032, the absolute level of rate increases is not directly attributable to the -- to the Preferred Development Plan. As Mr. Rainkie and Mr. Barnlund mentioned before me, that a good portion of those rate increases are caused by the thirt -- the cost to -- the cost recovery for the $13 billion in assets that are already on our balance sheet, the lower export prices we've seen more recently compared to historically, and the investments in aging infrastructure or our common capital that's consistent from each -- under each of the development plans, as well as our -- our progress towards reaching 75:25 again.

Now, we may have -- as we approach that 2032 time frame, depending on the cash flow -- level of cash flows and our progress towards the 75:25 and our other financial ratios, we may have some flexibility to ease off a little bit on the rate increases and smooth them over a longer period of time. It would probably result in -- in delaying the time in which you get back to 75:25, but may be mana -- manageable.

THE CHAIRPERSON: This graph looks very strange. Am I just misreading it? You know, it kind of implies a drop in rates.

MS. LIZ CARRIERE: That's the con -- correction factor.

THE CHAIRPERSON: I see a negative drop. I mean, in other words, you actually get a -- to get that kind of curve, you would -- you -- you would think that that curve would -- would be sort of flattening as opposed to actually dropping.

MS. LIZ CARRIERE: Yeah.

MR. DARREN RAINKIE: Mr. Chairman, that -- that's a very important point, because, as Ms. Carriere was talking about earlier, we've -- because we had two hundred and sixteen (216) financial runs to do, we didn't want -- we didn't -- we -- we couldn't just go through and do subjectively for each. It would nev -- wouldn't have possible to subjectively go to two hundred and sixteen (216) different runs and say, Well, let's have these rate increases in these first five (5) years.

And so what we did was we did a mechanical approach, where we put in rate increases -- or projected rate increases that would get us to the 75:25 by the end of 2032, and then after that, we put in projected rate increases that would meet the one point two-o (1.20) times interest coverage test.

And what happens is, once you build up to that twenty-five (25), then there's this, as we call it, the correction factor coming down. That's just a function and the mechanical nature of the calculations. In practice, we would not do that.

If you look at after the in-service of Conawapa in this -- in this scenario, you see that we're generating a significant level of net income and cash flow in the latter years of the twenty (20) year forecast. So what we would do is we would smooth that out in practice, but it -- it -- this is just a function of the mechanics, and I think it's an important thing for the Board to understand the difference between the mechanics and what we would do in practice. And so I think that's why you have to look towards the long-term trend. If we did it any other way, you'd probably see these very jagged rate increases, so you really have to, in your mind, draw a straight line through this when you're comparing alternatives.

And as -- as Mr. Carriere said, the reality, too, in the next five (5) to seven (7) years, before there's any new generation source in -- in place, we will be looking at the 3.95 percent rate increases if our forecast doesn't change. You know, it

-- once again, the mechanical way of calculating the All Gas scenario, you're searching between two (2) points, where you are now, and you're searching on the 25 percent equity ratio by thirty-two (32), and that gives you a 3.5 percent even-annual increase over those -- that twenty (20) year period.

And we did that because try -- we tried to make this understandable for the Board. We searched on a metric. We tried to find a metric on the rate side that was like NPV on the economic side, something that was understandable, rather than a series of, you know, rate and chan -- changes up and down. The mechanical search between those two (2) data points gives you 3 1/2 percent on the All-Gas Plan, but the reality is, in the next five (5) to seven (7) years, there is no new generation source in. We would be asking for the 3.95 percents under the All Gas Plan, as well. In fact, there's more pressure under the All Gas Plan, because we're amortizing some of the sunk costs of Keeyask and Conawapa.

So you have to -- you have to look at the mechanical nature of the calculations, and I think, in your mind, make some corrections for how this would work in practice. You know, we've seen in the media that, you know, because of the Development Plan, Manitoba Hydro's requiring 4 percent rate increases in the next twenty (20) years. That -- that's not correct.

In the next, you know, seven (7) to ten (10) years, we are requiring rate increases, primarily because of the refurbishment of existing infrastructure and reliability expenditures, such as Bipole III. That's not going to change between the development plans at this point.

What we are, from an accounting perspective and a rate perspective, is deferring any costs of Keeyask and Conawapa until they come into service. So I think it's important throughout this panel that we make sure we understand the reality of what will happen, the reality of the recommendations we'll be making to our Board and to the Public Utilities Board in terms of rates, and -- and recognize that because we were juggling two hundred and sixteen (216) sets of financial pro formas, we had to have some mechanical methodology to eliminate some of the subjectivity, and hopefully if we do our job in the next couple days, we'll -- we'll take you through that.

MS. LIZ CARRIERE: Just to add to what Darren has said, if we go to the next slide, we see that we're -- we're plotting here the All Gas case with the Preferred Development Plan, and you see that the same correction factor is in this plan as well.

So the important thing to note here is the differential between the plans, rather than the absolute value. In the All Gas Plan, it results in -- in rate increases over the first twenty (20) years of 3.43 percent, and that 3.43 percent is a -- a result of the same drivers as the -- as the Preferred Development Plan. It's our investments and existing infrastructure.

And, in fact, as Darren mentioned, under the -- the All Gas Plan, there's -- there is greater pressure to increase that -- that 3.43 percent even higher, because in this scenario, there's -- the All Gas Plan sees losses for seven (7) years due to the amortization of sunk costs. Would we actually implement three point four-three (3.43) and see significant losses over -- over seven (7) years and a deterioration in retained earnings balance? Not very likely.

We -- we would likely have to implement rate increases above that 3.43 percent, but for the purposes of demonstrating the differentials between the -- the plans based on the metrics, we're looking at three point four-three (3.43) rate -- percent rate increases.

Over the entire -- over the entire period, you can see there's the fifty (50) year period. We're looking at -- if we were to smooth out those rate increases, we're looking at 2.1 percent rate increases annually, compared to the 1 1/2 percent under the Pre -- Preferred Development Plan. By the end, we're seeing a 70 percent differential between the -- the All Gas Plan and the Preferred Development Plan.

On slide 42, we're adding the -- the Keeyask/Gas/750, or Plan 6, and you can see the -- in the first twenty (20) years, the rate increases are relatively similar to the -- the All Gas Plan at 3 1/2 percent per year. Over the entire period, we're looking through -- over the fifty (50) year period, you're looking at rate increases of about 1 percent -- 1.8 percent per year, pardon me.

And it -- by the end, it's partway between the cumulative rates by the -- 2062 are partway between the -- the All Gas and the Preferred Development Plan, with about 33 percent change in the -- in the cumulative rates.

Because we don't quite have the DSM evaluations ready yet, which would incorporate the -- the higher capital costs that you've heard about over the preceding weeks, just as a proxy, we've -- we've plotted the high capital cost scenario that was prepared in August under your -- under reference economics and reference export revenues to show you that the approximate impacts of -- of that higher capital costs on the cumulative rates.

Those in-service costs for -- are comparable, and they result in slightly higher rate increases. The -- under the Preferred Plan, the -- that scenario resulted in 4.27 percent rate increases, but the Corporation may be able to manage maintaining the -- the 3.9 perc -- percent rate increases by deferring the time in which the -- or the year by which the -- the debt equity ratio returns to 75:25.

On slide 44, it takes -- it takes the slide 42 and converts it -- it takes -- removes the inflation and converts it into real dollars. Now, we can see that over the -- the fifty (50) year period, that once we get past the -- the 2032 time period, we see no real growth in -- in the Preferred Development Plan cumulative rates, and moderate growth in the Keeyask/Gas/750 and the All Gas Plan over the fifty (50) year time frame.

In PUB-149(a), we filed a present value analysis of the consumer's revenue. Based on economic theory, we discounted it at the social time preference rate, which addresses the relative impatience -- or -- or patience for consumption and intergenerational equity. Higher discount rates would imply that we're looking at a shorter analysis time frame, and places later -- less value on -- on revenue, or consumer's bills, or rate -- rates in -- in -- far into the future.

The discount rate that was used in this analysis is 1.86 percent real, based on projected real return on short-term Canadian T-Bills, and they were before income tax -- income tax adjustments. It reflects Manitoba Hydro's investment in -- in a -- the province's public infrastructure, and the long-lived assets of a hundred years or more.

It doesn't reflect the weighted average cost of capital, which is used in the economic analysis, the -- because the cost of corporate debt and equity are inherently included in the consumer's revenue. Consumer's revenue is calculated, including financing charges, so to then use a cost of capital to discount consumers revenue is like -- is -- is double counting for that cost of capital.

Additionally, in the uncertainty analysis, we've accounted -- we've adjusted the underlying assumptions and variables for risk, so to use a -- a higher discount rate would also double count that risk. It doesn't reflect the high investment threshold for private sector represented by the cost of capital, as that is used in the economic analysis.

So looking at the differential of the cumulative present value on the consumer's revenue, we're seeing the Preferred Development Plan crosses over the -- the All Gas Plan by 2046, which is seventeen (17) years following the last unit in service of Conawapa. Compared to the Keeyask/Gas/750 rates under -- on a present value basis, are -- are lower than the -- the Keeyask/Gas/750 by about 2050, which is about twenty-one (21) years following the in-service -- the last unit in service of Conawapa.

By the end, we're looking at 2 billion to $3 1/2 billion benefit to customers by developing both Keeyask and Conawapa, and the 750 interconnection.

(BRIEF PAUSE)

MS. MARLA BOYD: Mr. Chairman, that concludes Ms. Carriere's portion of the direct -- that section of the direct, sorry. I'm just wondering if the panel would like a break at this point, or if you'd like to carry on?

(BRIEF PAUSE)

DR. HUGH GRANT: At the risk of delaying people's breaks, could you just go back to, say, slide -- well, I want to come back to 46, because I want to make the comment that I have no children, and so I'm not particularly persuaded by this graph, but if you went to slide 46, I don't understand the -- sort of the accounting principles that go on here, but it would seem to me, when you get this, you know, the cumulative path, that the reason why you're getting this sharp change -- yeah, this is fine. It's really you're just saying you're changing your sort of -- the -- the target that you're focussing on.

And so I'm just curious for the -- so this initial twenty (20) year period where you're talking about trying to restore the appropriate equity-to-debt ratio, is this really an appropriate time to be worrying about -- here -- here's what I want some advice on.

What should I -- what should I be concerned about with this debt-equity ratio? Why is it important? Wh -- what's magical about the 75:25? And in an era of historically low interest rates, is this really a time to worry about getting my equity debt ratio back to this sort of targeted level?

Isn't this -- isn't this a time to be kind of loosey-goosey with our money and get over-leveraged and stuff?

MR. DARREN RAINKIE: Mr. Grant, I think I'll take that one, because there's a couple of really good reasons to -- to -- for -- to look at this. Number 1, the rate stability for customers in the future is based -- is going to be based on our financial strength. So we can't afford to say, Let's be, you know, laissez-faire about our financial strength. So certainly if we kick the can down the road, we build up rate pressures for future generations, which is not acceptable. It's intergenerational inequity.

Secondly, we borrow the lion's share of our money through the Province of Manitoba. And at this point, and Mr. Schulz will go over this at -- in his part of his presentation, our debt is looked at as being self-supporting. We pay our own freight. When credit rating agencies review the Province of Manitoba, they push that debt off to the side and say, Manitoba Hydro will cover that, so we're not, you know, applying a credit rating to the Province of Manitoba assuming that debt.

If we don't look at the financial integrity and say it's unimportant of our -- of our company over time, there's a possibility they could look at that debt as being non-self-supporting and negatively impact the credit rating of the -- of the province. We don't think er -- it's ever going to come to that, but those are two (2) good reasons why we need to be very careful about this: rate stability and ensuring that we continue to have access to low-cost debt, both ourselves and the province.

DR. HUGH GRANT: No, I -- I understand that point. It just seems that, clearly, Hydro has decided at -- at some periods of time it's prudent to actually have a higher debt-to-equity ratio, and at times it's better to have a lower one. It just seemed to me that in this climate of historically low interest rates, the cost of driving your debt-equity ratio up -- it's -- it's less costly in this -- this climate than maybe it had been in other ones. And so it's just really a choice of between increasing ratepayers' fees versus borrowing more heavily.

But can I -- and I'm -- I'm glad you mentioned intergenerational equity, because that comes back to my other point about the fact that I have no children. It is interesting, because, you know, combining the argument you've just made with the debt-equity ratio in terms of that slide 46 showing this pattern of rate increases.

I mean, what you're saying is that this current generation should bear the cost. It's quite different from some of the arguments you hear in the press. It's that this current generation should bear the cost of high -- high rates as a bequest to some future generation, which, again, is going to appeal to some members of the panel who have children, but not to me.

MR. DARREN RAINKIE: Mr. Grant, a couple of observations on that. As I mentioned earlier, I don't foresee there being any differential in the rate increases between any of the plans in the next six (6) to eight (8) years. So the -- the rate increases that we're looking at in the next number of years are, as Mr. Barnlund indicated, directly related to the reinvestment in aging infrastructure that we need and other cost pressures.

Secondly, there is -- part of the intergenerational equity argument that's missed by even those individuals that don't have children is that your rates -- your low rates today are based on investments that have been made by past generations of Manitobans. And we feel that it's appropriate -- I mean, this is a continual investment business. This is what this business is about. There's no time frame. Manitoba Hydro is a capital company, 60:40 capital operating company. It's always investing in assets.

So I've been asked before by people around the table, Well, I'll never see the benefits. The answer to that question is you already see the benefits of Hydro generation in your current bills. And I think it's fair from an intergenerational perspective to continue to invest in that.

And as -- as Ms. Carriere said, the -- the change that you see, the correction factor, is a -- from moving from the debt-equity to the one point two (1.2) interest coverage is a -- is a function of our -- of our -- the way we bake the financial calculations into the model.

The reality is, is that we would smooth -- we would smooth that out. And -- and we would -- at that point, if -- if we are getting the kind of net income and cashflow that we're projecting here, we would look to the credit-rating agencies and say, Look at, we're moving towards our -- our equity targets in -

- in a nice fashion. And we would probably take the top off of that projected rate increase that you see here. We would flatten it out, which would serve to reduce any intergenerational equity consideration.

So I think in practice we can manage it so there's very little inter -- intergenerational equity between different generations of customers.

THE CHAIRPERSON: I kind of -- I kind of consider the debt-to-equity as kind of a shock absorber for the -- for -- you know, for Manitoba Hydro. And I would -- I would have thought that you would have put more emphasis on the interest coverage ratio, because that reflects your ability to pay back -- pay back interest costs on the debt that you've incurred; and, to some extent, the capital coverage ratio because you want to make sure that, you know, you've got adequate funds to keep investing.

So I'm a bit surprised that you would emphasize debt-equity to the extent that you have as opposed to the more critical one, in my opinion, which is the interest coverage ratio, which is the one you have to sort of talk about when you meet your bond-rating agencies and, I suppose, ultimately, the people who buy your bonds.

MR. DARREN RAINKIE: Well, Mr.

Chairman, and, actually, in this financial analysis, it's funny you mentioned that, I think we started out by searching the -- or projecting the rate increases based on the interest coverage ratio, but it -- it resulted in this, you know, up and down movement of rates. And I think the information provided to the panel made useless. It just...

So we -- we searched on the -- on the equity ratio because it was what the Board had seen in IFF12, in terms of trying to get back to the 25 percent by the end of the twenty (20) year period.

But we look at all the ratios as being important. I think -- you know, and -- and the credit-rating agencies look at interest coverage. But we also have to look at the -- the health of our -- our balance sheet. So I think we're trying to manage all of these things simultaneously.

I -- I wouldn't take from the financial analysis that one's of expre -- extreme importance and the other one is not important. I -- I am concerned when I look out. When I look at the interest coverage that we have, it's, you know, coming up to, you know, between one (1) and -- and one point one (1.1). I think we -- we need to manage that carefully.

And, I mean, I guess that's the other

point here, is these are financial projections. But we also, as the management of the Company, have to manage our expenditures appropriately. And this is a long-term, twenty (20) year financial projection, and it stems out to fifty (50) years if you do the rate analysis.

Obviously, we're -- management will be taking actions in those years to try to manage that interest coverage so that it isn't at, you know, point eight (.8) or point nine (.9). And that's the other factor, I think, that gets lost. You -- you'll see a lot of quantitative information throughout all the different panels and Intervenor experts.

And -- but there's also a management actively looking at this at Manitoba Hydro and a board actively looking at this and -- and making decisions along the way. And, you know, we are looking at even rate increases, and from a forecast perspective, a three nine five (3.95). But if something happens and we get into a bit of, you know, issue, we may have to move that up or down, depending on the circumstance.

So I think it's just important to look at what you're seeing in a long-term projection here and that, you know, there is somebody managing the situation, as well.

MR. MANFRED SCHULZ: Sorry, and if I just may add as well, from a credit-rating perspective, the credit-rating agencies will look at both the amount of leverages reflected in the debt-equity ratio. They'll also look concurrently at the interest coverage ratios.

What we do find is they act and -- the trajectory of the slope of the curves tend to be very similar to one another. Ms. Carriere already alluded to that. So when we're looking at -- and Mr. Rainkie indicated this, as well, we look at all of these ratios in concurrence and in cohesion.

The debt-equity ratio, it was part of the presentation that I will yet -- has yet to come. And we can perhaps have an expanded discu -- discussion on it at that point in time. But the leverage in the debt-equity ratio is a key one. Is there some flexibility to move it? We'll show you in a later slide the history going back to 1962 of the equity ratio, and perhaps we can have that discussion at that point in time.

But we need to have balance between the performance against these ratios as well as against the customer rate increases and so on. And we can certainly -- and we're looking forward to having that discussion as we continue.

THE CHAIRPERSON: Okay. It's probably an appropriate time to take a break. Why don't we take fifteen (15) minutes, and --

MR. BYRON WILLIAMS: Mr. Chair --

THE CHAIRPERSON: -- be back at 11:00.

MR. BYRON WILLIAMS: -- Byron Williams here.

THE CHAIRPERSON: Mr. Williams, go ahead.

MR. BYRON WILLIAMS: I wonder if I might be permitted to ask a question of clarification of Ms. Boyd, and then it may have some ramifications on how long the break is.

Ms. Boyd, we understand from the discussion of the Chair with Mr. Rainkie this morning that the information presented today does not include the DSM scenarios and that there'll be an update in terms of those implications on the financial evaluation provided on the 24th.

Am I also correct in suggesting that the information does not fully reflect the updated capital information that was presented on March 10th?

(BRIEF PAUSE)

MR. BYRON WILLIAMS: Leaving aside slide 43 as a proxy.

MR. DARREN RAINKIE: Mr. Williams, if I put my accountant hat on and get into the lawyer-to-lawyer discussion here, if you look at slide 43, that's the reason we put the reference/reference/high capital case on the slide for the time being, is that it's a reasonable proxy of the refined capital costs that we saw earlier in the start of this proceeding. The DSM will be layered on top of that for the material on the 24th.

MR. BYRON WILLIAMS: I -- I don't want to preempt anyone's cross, but I -- I'm just trying to understand. Presumably the revised capital information, Ms. Boyd, will have -- will have implications for the -- the analysis that's provided on the 24th, as well?

(BRIEF PAUSE)

MS. MARLA BOYD: I can direct you back to Manitoba Hydro Exhibit 90, which lays out the time frame and some of the details of what's intended to be provided on those dates. And -- and I think the point that Mr. Rainkie was making is that the -- the material that's before you now includes the high scenario, which will assist in comparing to the new capital costs.

MR. BYRON WILLIAMS: Okay. Thank you. I'll caucus with my colleagues at the break.

THE CHAIRPERSON: Okay. Let's break and we'll see each other again at eleven o'clock. Thank you.

--- Upon recessing at 10:46 a.m.
--- Upon resuming at 11:04 a.m.

THE CHAIRPERSON: Apologize for the slight delay. I believe we're ready to resume the proceedings, so back to you.

MS. LIZ CARRIERE: Okay. Moving on to the uncertainty analysis. What we've got in this graph on -- on slide 48 is -- the solid line is the reference scenario with -- the high/low/high scenario is on -- is -- represents the top bar, and the low/high/low scenario represents the bottom bar.

So this kind -- this represent -- these -- these two (2) scenarios represent the kind of outliers of the -- of all twenty-seven (27) scenarios. Now, you'll note that this is based on the actual scenario runs, and not the pro -- probability values that were included in the original Chapter 11. So these -- how -- you can use these to reference back to the cumulative rates that are actually in the projected financial statements in Appendix 11.4.

In the 2032 time frame the range of the cumulative rates under the Preferred Plan can be from 41 percent to 210 percent, and by the end of the fifty (50) year period we're looking at cumulative rates in the range of -- of 38 percent to 222 percent. Moving on to graph -- or slide 49, what we've done here is plotted the high inflation interest scenario, or the high economic indicator scenario with reference export prices and reference capital costs, and similarly with the low inflation and interest scenario.

What this shows you is that the uncertainty in -- in the Preferred Development Plan is predominantly due to factors such as interest and inflation. Approximately 60 percent of the variable can -- is contributed by this factor in -- by 2032, and about 85 percent of the variability in -- in the range of cumulative rates contributes to -- or the inf -- inflation and interest factors contribute to the -- the uncertainty by 2062.

It's important to note that this isn't solely caused by the Development Plan itself.

Remember, we still have the $13 billion in assets and refinancing of the debt tied to those assets, and once -- once there's some -- some uncertainty related to Keeyask and Conawapa until you get it in -- in-service, but once that in-service, as long as those -- the -- the long-term financing that's tied to those -- those facilities are -- are generally stable until the need to refinance those as well. So a lot of the uncertainty under high interest and inflation, particularly in the middle period, is related to the underlying infrastructure investment.

Moving on to slide 50, we've plotted the low export/gas price and the high export/gas and electricity prices, and you can see from this graph, is that during the construction of -- of Keeyask and Conawapa under the Preferred Development Plan, there's -- there's a moderate amount of uncertainty until they go into service, but thereafter, the -- the export -- electricity export prices and -- and gas prices have much less of effect than -- than interest and inflation. It accounts for about 30 percent of the variability in -- in the 2032 time frame, and only about 10 percent by -- by -- in the fifty (50) year time frame.

Looking at capital costs, now this is

the -- the -- looking at the change in -- in base capital cost estimates, so it would include interest and escalation at reference on those higher or lower inter -- capital costs, but you can see that capital costs also only has a very moderate effect on the uncertainty relative to the reference scenario in the Preferred Development Plan. It's less than 5 percent by the end of the fifty (50) year period, and about 12 percent of the variability in the interim.

On slide 52, we're looking at the uncertainty, or -- or the range of scenario, the twenty-seven (27) scenarios under the All Gas Plan. It results in less uncertainty in the 2032 period, but much greater uncertainty relative to the Preferred Development Plan by 2062. At 2032, your cumulative rates are between 51 and 94 percent, and by 2062, those -- the range in -- in cumulative rates can be from 72 percent to 403 percent. By comparison to the Preferred Development Plan, the highs are higher and the lows are lower under the -- the All Gas Plan.

Similar to -- moving on to slide 53, and similar to the Preferred Development Plan, the uncertainty is predominantly caused in the -- in the High Gas -- in the All Gas case due to the inflation and interest factors. It accounts for about 75 to 80 per -- 85 percent of the variability.

And the reason why that the variability is greater under the All Gas Plan, and you'll see this in a later slide, is that in the All Gas Plan, there is a continuous investment in gas turbines all through the forecast. So we're seeing the effle -- effects of in -- inflation and interest on those -- those future investments in increasing the variability and the overall rate increases, whereas in the Preferred Development Plan, all -- essentially, once you have Keeyask and Conawapa in service, you know, you're -- you're limiting the -- the variability in -- to that period of time related to the Development Plan.

On page 54, we're looking at the high electricity export prices, as well as gas prices, and -- and conversely the low prices. In the period to 2032 the low gas results in higher rates. There's no new generation, thermal or hydro, until a later period -- until the latter period. The variability is, again, due to the existing system in that twenty (20) -- period to 2032.

After 2032, the converse is true, or the high -- high gas results in higher cumulative rates and the low gas results in lower cumulative rates due to the higher cost of operating of the -- the gas -- the gas facilities. It's also the opposite from the Preferred Development Plan, where high gas export prices result in lower rates.

And on slide 55, we are looking at the sensitivity to the high capital cost scenario. We can see from this graph that there -- there is minimal impact due to the base capital cost on -- on gas turbines. In fact, it's less than 5 percent over the entire fifty (50) year period.

In -- in the interest of time, we haven't graphed the uncertainty for the Keeyask/Gas/750, or Plan 6. But what you can -- you know, by inference it -- the -- the uncertainty falls in between the -- the uncertainty that we see for the -- the All Gas Plan and the -- the Preferred Development Plan.

So in terms of the customer rate analysis summary, under all of the scenarios that we evaluated, we're looking at rate increase above the rate of inflation due primarily to the investments in infrastructure, and reliability, and the reduction in the non-firm export prices. Rate increases in the period to 2032 are moderately higher under the Preferred Development Plan than All Gas and the Keeyask/Gas/750.

Under the reference scenario, the -- the Preferred Development Plan rates are lower than All Gas and Keeyask/Gas by 2035, in a relatively short time frame following the in-service of Conawapa. On a present value basis, the Preferred Development Plan revenue is lower than All Gas by 2046, and lower than Keeyask/Gas/750 by 2050 -- by 2050, about a twenty (20) year time frame following the in-service of Conawapa.

The costs of the Preferred Development Plan do not directly affect Manitoba Hydro's electricity rates today. Those costs are deferred in capital until in-service, at which time they're included in net income and revenue requirement, and amortized over the lives of the associated assets.

Once in operation, the Preferred Development Plan is expected to assist in maintaining affordability and -- and competitive Manitoba Hydro rates. The costs are spread over a very long time, matching when customers receive those benefits. Carrying costs commonly decline over time for hydro generation assets. And exports offset the costs passed on to ratepayers.

(BRIEF PAUSE)

MS. LIZ CARRIERE: So if we're ready to move on, we can move onto the impact on Manitoba Hydro's financial position.

MS. MARILYN KAPITANY: Can I just ask one (1) question before you move on?

MS. LIZ CARRIERE: Sure.

MS. MARILYN KAPITANY: The top bullet on that page where you talk about the customer rates, I understand the existing infrastructure. Could you just say a little bit about the reliability, what reliability is going to be added in the -- the rate increases? And also the reductions in non-firm -- non-firm export prices.

Could you speak a bit more to those two (2) parts of the rate increase?

MS. LIZ CARRIERE: So existing infrastructure in major -- that covers all of the base capital plus some of the rehabilitation and refurbishment of -- of new -- or existing generating stations and transmission lines, and so forth. There are also new projects in -- related to improving reliability, Bipole III being one (1) of them.

Reductions in the non-firm export prices, this is where we're talking about we've seen deterioration in extraprovincial revenues over the last several years, and that's primarily due to the -- the opportunity prices, so not our firm contracts, but the opportunity prices in the export markets.

(BRIEF PAUSE)

DR. HUGH GRANT: Just one (1) very small point, and this would compound your life and the work you'd have to do, but in each of these sort of uncertainty scenarios you're just saying, Suppose its capital cost variable is higher than a reference point, and we project that through for fifty (50) years, right? Since a lot of this discussion is really about timing and windows of opportunity and such, did you ever run any scenarios to say, Suppose capital costs are high over the next ten (10) years and then fall, or -- you know, in -- in terms of breaking up this fifty (50) year period into different sort of scenarios?

MS. LIZ CARRIERE: No, we didn't do that analysis, because if you -- if you assume that -- we're looking prolonged periods of rises in capital cost increases. Now, presumably, if it were to rise and then fall, it would fall back towards the reference price, so we intended that the -- the scenarios that we looked at were kind of the outliers, not cyclical types of analysis.

(BRIEF PAUSE)

MS. LIZ CARRIERE: Okay. So moving onto slide 58 --

THE CHAIRPERSON: I wonder if we could have a quick discussion. I mean, I -- it -- it's in relation to capital costs and a scenario whereby the capital costs of the nearby facilities are higher than what was projected, so specifically, excluding Bipole, you know, we are talking about a -- a major investment in Keeyask, and we're talking about a very significant investment in a transmission line, the total of which, I think is about something in the order of 7 billion -- 7 billion at the moment, seven (7) -- assuming -- I mean, the -- the transmission line costs are -- are kind of floating right now, but it's six point five (6.5) for Keeyask, and then potentially 800 million for -- for the transmission line, or I've -- have I got -- am I going too high, there?

If that -- what -- what -- let's -- assuming that figure is seven point three (7.3) or something like that, and so that -- the -- they -- the projects come in at, say, a billion over what we had projected, so that would imply that interest costs -- we would -- we would pay half of that off -- well, a quarter of that off to equity, to -- to retained earnings, so that's -- that leaves 750 million.

And I'm looking at depreciation of what, Mr. Rainkie, 50 million on that? I'm just guessing here. I mean, humour me. Something in the order of what, say, a 750 million -- or a billion dollar investment overrun results in depreciation and interest costs of what number? Give me a -- give me a figure.

(BRIEF PAUSE)

MR. DARREN RAINKIE: For lack of a fine point, Mr. Chairman, let's say 8 percent, six (6) -- six (6) for finance, 2 percent for depreciation.

THE CHAIRPERSON: Yeah, and then --

MR. DARREN RAINKIE: Probably a little lower than that, but --

THE CHAIRPERSON: -- translating that into -- translating that into a -- into a -- a percentage rate increase, we're looking at something in the order of what, 10 percent? You know, or am I -- is that too much, or -- if you wanted to maintain the boat on an even keel?

MR. DARREN RAINKIE: The -- the difficult part with those types of calculations, the one (1) year in-service calculation, is that it's not really a reflection of what really would happen. In fact, when -- when you look at the -- I'm trying to remember some of the -- the runs that -- and maybe this will become clear when we file the runs with the higher capital cost, is that -- is that even with the higher capital costs of Keeyask and Conawapa, which were, I suppose, approaching the order of a billion dollars, I think it was a $300 million change and a $500 million change, I think the -- the pressure on rates in the first twenty (20) years would only be a quarter of a percent.

And if you stretched out the timing of the achievement of the 25 percent equity ratio, I think we could still maintain the -- something close to the 4 percent. It's simply a function of the fact that once you have these generating stations spinning, you have a significant cashflow and net income, you know, at the back end.

And one (1) of the things you have to look at in a hydroelectric generating station is the financial profile of it. People tend to look at the first ten (10) years when it's in service. But the financial profile of a hydroelectric generating station is, yes, it's a lumpy piece of capital that comes in, but as -- as we generate income from it to start paying down the debt over time, the costs actually go down.

If you assume, you know, a normal economy, where prices are gradually increasing, there may be business cycles where it goes up and down, but we're talking about a hundred-year asset here. The -- the revenues out of it are coming up, right. We have a cost-of-service type of mentality, where we feather in rate increases over time. We don't -- we don't take the actual carrying costs of an asset and jam it right into rates the first year.

When you combine all of those factors into the -- into the mix and look at the financial profile of a hydroelectric generating station, once you have that, even if there are some cost overruns, and we don't want that to happen and we're going to carefully manage that, it still is a hugely viable -- it's still the -- the cheapest, lowest cost electricity you're going to get over the long run. And -- and it's manageable because we don't take all of the carry -- the extra costs of -- of the overrun and jam it into rates on year 1.

So it's -- it's -- sorry, that's a bit

of a long-winded answer, but you have to look at the financial profile -- to understand the real answer to that question you have to look at the financial profile of a hydroelectric generating station and understand what you're dealing with.

When we tend to do these one (1) year revenue requirement calculations the year it comes in service, it -- it results in a picture that just doesn't -- doesn't make sense. And I think we're going to get into that -- I've looked at Mr. Peters's book of documents -- later.

But when you look at things -- when you look at the financial profile, you -- you got to get past the first ten (10) years where you're not generating enough revenue to cover the costs. You have to look at the entire time frame of that generating station. And I think that's one (1) of the points that's maybe miss here in the -- in the proceeding.

People tend to get scared at the upfront investment, but they don't look over the long ,run.

THE CHAIRPERSON: Just, you know, it's -- just to argue -- it probably is just to -- the debate we're having, you know, the -- you've already established what your revenues are. If you -- if you make a mistake on the capital costs, there really no --

there are no more revenues to be obtained from the marketplace other than what you can get from ratepayers.

And I'm simply trying to establish a worst-case scenario whereby something goes wrong in the capital construction costs and that the impact of that, in broad view, goes right to ratepayers at the -- at the front end. I'm very concerned about the potential that -- that our carefully crafted pictures that we're drawing here, if we are wrong, the ratepayers get it right on the chin at the front end.

And I just want to be convinced otherwise.

MR. DARREN RAINKIE: That's what I was trying to convince you, Mr. Chairman, in my rambling responses, is that -- is that, if you had a cost overrun of a billion dollars, I think was your scenario, just for a round number, and if you assumed the carrying costs were 8 percent, $80 million, we would not jam that into customers in the front end.

There is sufficient benefits from a hydroelectric generating station over the hundred-year life that we would smooth -- we would smooth that in over time. So the customer would not all -- the -- the customers at the front end would not pay the freight --

all of the freight, if you like, that we would allow that through our cost-of-service rate-setting methodology to come in over time.

Of course, customers have to pick up the total cost of the Company over time. I mean, it's -- it's just the fundamental, you know, principal of Manitoba Hydro. There's no shareholder here that's earning a 10 percent return. We -- we work on behalf of the -- 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 -- in the end, the retained earnings that we have are for customers. They're not for a shareholder. They're not for bonuses.

But the -- the beauty of a hydroelectric generating station is that you have that flexibility. If there are some things a little bit off the beaten path in the front end, there's more than enough cashflow in the back end -- well, and -- and starting right when it starts to go in-service, to -- to cover that off without needing to go directly to customers and -- and tapping their pocketbook. And that's a fundamental thing here, is understanding the financial profile of the hydroelectric generating station.

(BRIEF PAUSE)

MS. LIZ CARRIERE: So on slide 53 we're looking at the net income of electric operations under the three (3) development plans reference scenario. And what you can see is that each of the development plans result in relatively low levels of net income in -- in the first ten (10) years.

The All Gas Plan results in losses for seven (7) years, mainly due to the amortization of the sunk costs relative to the Preferred Development Plan. And rates in practice would need -- likely need to be adjusted higher so as not to substantially deplete retained earnings over that ten (10) year time frame. Net income over the longer term converges and -- and is a result of the -- the adjustment of the -- the rates to meet the one-twenty (120) interest coverage target.

On the interest coverage ratio, we tend to -- it's almost a mirror image of the -- of the net income graph. We're below target for twelve (12) to fourteen (14) years under each of the scenarios. The All Gas net losses on the previous slide also results in interest coverage below one (1) for a number of years.

While the interest coverage weakens in

the first ten (10) years, we -- we see improvements thereafter and get back to -- to the one point two (1.2) times target level in the 2026 time frame under all plans; and under the Preferred Development Plan it's once Conawapa is in service. The Preferred Development Plan maintains the one point two (1.2) times interest coverage taro -- target, assuming lower rates over that time frame.

On slide 60, we're looking at the equity ratio under each of the plans. The equity ratio deteriorates to between 8 and 10 percent in each of the development plans on this scen -- in -- in this graph here. Rate increases of three point four (3.4) to three point nine-five (3.95) return the debt-equity ratio to 75:25 by 2032. And we see improvement in the debt -- debt-equity ratio thereafter.

On slide 61, we've got -- we've plotted the -- the net assets of the Preferred Development Plan and the All Gas Plan. Now, this is where we're -- I was mentioning earlier, we've also indicated where the in -- in-service of each of the facilities are under each of these development plans.

So we can see in Keeyask and Conawapa, over a two (2) year -- year period, the seven (7) units coming on line there. And then the Conawapa units 1 to

10 coming in -- in-ser -- into service over a three (3) year period. And then you'll note much further down, in the 2040 time frame, we're adding three (3) simple cycle gas turbines for peaking capacity.

In the All Gas Plan, we're looking at the addition of either simple cycle or combined cycle over the entire fifty (50) year period to either meet peaking capacity or energy requirements, but you'll note that by the end of the forecast period in 2050s, we're actually replacing the assets that have been put -- put in service in the early '20s due to the thirty (30) year expected life of gas turbines.

So you can see that we grow from about 13 billion to 37 billion under the Preferred Plan, with net expenditures of about $18 billion, and somewhat surprisingly, we've got $9 billion in All Gas net expenditures and reach to $32 billion by the end of the for -- the fifty (50) year time period. So we're really only seeing a differential in net assets of about $5 billion after depreciation -- accumulated depreciation, and so forth.

On slide 62, we are looking at the -- the net debts that's none of -- that's our long-term debt, plus our notes payable less sinking fund and short-term investments. The Preferred Development Plan reaches a peak at the Conawapa in-service date, and declines over time as the assets depreciate and the financing costs are -- are being paid down by export and domestic customers.

The All Gas debt increases over time as investments in gas turbines are made over -- over the entire study period.

MR. DARREN RAINKIE: Mr. Chairman -- and I'll give Ms. Carriere a moment to catch her breath, because these are two (2) of the most important slides that you'll see in the slide deck, and I think it's -- hopefully will provide a decent perspective for the Board. This is what I was trying to go through a few minutes ago.

You know, if you read the media report -- reports about our Preferred Development Plan, people are trying to set this up as this risky great big hydro plan versus this tiny little gas investment that you make at the -- at the front end, which is, of course -- slide 61 shows you a -- a quite different perspective.

What you're doing on the hydro side, yes, it's a hydroelectric side. It's a much larger investment, but what you have, then, is a very low cost, fixed source of generating electricity, and it's not a great big risky investment at the front versus a little tiny gas turbine. It's a investment in a very low cost, stable plant at the front end, albeit at a higher -- you know, at a -- at a higher investment versus a number of investments in gas plants over time, and you can see that the balance sheet is fairly close to convergence by the back end of this thing, if you take a longer perspective on it.

Then you flip to page 62, and what you see is that despite that larger investment at the front end, the net debt converges under these plans. The difference between assets and net debt, of course, is equity. We have more equity at the back end with the hydroelectric generating facility. This is what I mean about the financial profile of a hydroelectric generating facility.

You've got to take the long view on this and take a look at it. It's not the risky hydro plant versus the tiny little gas investment. It's the stable, low cost, larger investment at the front end versus a series of investments under All Gas, but in the end, we end up with the same level of net -- of net debt and higher levels of equity.

This is the Company's perspective on why we believe, financially and from a rate perspective, that this is the best plan to proceed on.

MR. RICHARD BEL: Excuse me, in -- in slide 61, where's the cross -- or where does the -- the Plan 6 -- Plan 6 must meet -- it's in between but closer to where? It's not in this slide, Plan -- Plan 6, the Keeyask/Gas Plan.

MS. LIZ CARRIERE: You're correct. In the -- Plan 6 you would see closer to the Preferred Development Plan around the time when -- when the Keeyask units are coming into service, and then it'll sit slightly below that for the remainder of the forecast period.

MR. RICHARD BEL: Okay. Okay, thank you.

MS. LIZ CARRIERE: On slide 63, as Darren mentioned, the -- the other side of the assets, and -- and liabilities leaves retained earnings, and under the Preferred Development Plan, we see retained earnings that are consistently higher than the All Gas Plan by about 2 1/2 to $3 billion over the entire study period.

Similarly, the Preferred Development Plan is 1 to $2 billion higher than the Keeyask/Gas/750. Sufficient retained earnings is critical to Manitoba Hydro's to be -- to absorb the financial impacts of adverse events for a short period of time in order to provide some protection to ratepayers. One (1) of those events that we'll be looking at is drought.

It's known to be one (1) of Hydro's highest impact -- or a high-impact risk with a high probability of occurrence, and this analysis analyzes the recurrence of one (1) of the worst droughts on -- on record, or the lowest extended period of low water flows. Because Hydro's system is predom -- or the -- predominantly is a hydro-based system, this risk exists regardless of the development plan that we choose.

You can see in this graph that the absolute value of retained earnings as at March 31st, 2026, with and without drought, and under both the Preferred Development Plan and the All Gas Plan, the relative impact to rate -- retained earnings is nearly $2 billion, and this is the result of the prot -- predominant -- predominantly based hydro system prior to investment in either Gas or the Preferred Development Plan. So we're seeing approximately the same cost of drought under -- under either plan.

Now, these -- these costs are including financing charges, and assumes that our rates are held constant in -- in the base case, without drought that we're using for comparison.

On the next slide, we're looking at the -- the drought in the period -- the same drought occurring in the period between '27/'28 and '31/'32. So this is the -- the -- kind of the final stages of construction of Conawapa, and Keeyask is in-service in this case. The -- you can see that the relative impact to retained earnings is higher in this later drought, compared to the previous slide under both the Preferred Development Plan and the All Gas Plan, rather than -- you know, in the previous, we were looking at about approximately a $2 billion cost of drought. We're now looking at about 2 1/2 and 2 billion -- or one point nine (1.9) to two (2) -- 2 1/2 and 2 billion.

The Preferred Development Plan impact -- drought impact is greater than the All Gas Plan due to the need to run thermal -- thermal fuel options, and -- and power -- and purchase power. The Preferred Development Plan retained earnings is higher in the base case without drought, and so is better able to absorb the impacts of a drought. And you can see that the Per -- Preferred Development Plan with a drought is a little bit higher than the All Gas Plan without a drought.

On slide 67, we're looking at the same drought again in a later period, and again, we see the increase in the drought cost under the Preferred Development Plan compared to earlier droughts. We're now looking at, rather than 2 billion and $2 1/2 billion impacts, that we're up to $3.2 billion impacts, but again, retained earnings are sufficiently high to absorb the cost of -- of drought without adversely affecting customers.

Again, retained earnings with a drought under the Preferred Development Plan are greater than the -- the All Gas Plan without drought.

(BRIEF PAUSE)

MS. LIZ CARRIERE: So just in summary, on the financial impacts of -- on the financial position, net income interest coverage and debt-equity-ratio weaken initially, and then improve gradually to 2032 under all development plans. Net assets and retained earnings are the highest under the Preferred Development Plan.

The net assets under the All Gas Plan grow steadily over the study period, and are only 5 billion, or 13 percent, lower than the Preferred Development Plan by the end of the study period due to the continuous investment in gas turbines over that study period.

The Preferred Development Plan has the highest level of net debt throughout the study period, but declines following the hydro generation in-service dates and converges with all the other -- the debt of all of the other development plans by the end of the forecast.

The All Gas Plan has the lowest level of net debt initially, but increases throughout the study period, converging with the Preferred Development Plan by 2062. The Preferred Development Plan results in the strongest projected balance sheet, with the highest level of assets and retained earnings over the entire study period.

And the impact of drought is greater under the Preferred Development Plan. However, the -- due to the higher net assets and retained earnings, the Preferred Development Plan is in a stronger financial position to absorb the adverse financial impacts of drought.

THE CHAIRPERSON: Could we go back to -- could we go back to sixty-five (65), please? Could you explain why there isn't more of a difference between the two (2) alternatives here in relation to that time period? You know, there are a lot of people out there who say that if we had a -- a gas unit available in Manitoba, the thought occurs that we can pull on that unit to supply a Manitoba load. We don't have to import power at high cost.

Why would there be much more of a difference here than -- than that's -- than what's showing up in these numbers?

MS. LIZ CARRIERE: Because at this point in time -- whoops -- the -- the system is still predominantly hydro, so you're still looking at, you know, 95 percent of all of the electricity is coming from hydro sources, so having a -- a CT come online at this point doesn't alter the fact that the costs of -- of drought on the rest of -- of the existing system.

(BRIEF PAUSE)

THE CHAIRPERSON: But this one -- this one is -- this one is, in effect, supplanting Keeyask. If you go the All Gas route, you're supplanting the construction of Keeyask. So, presumably, the amount of power generated out of Keeyask would be impacting the -- would be impacted by drought. Meanwhile, you're running your -- you're running your -- your combined cycle turbine, or your -- your single cycle turbine.

So having established that there's less water flow, there would be less revenue out of Keeyask. You wouldn't be importing with -- you know, wis -- with -- I'm trying to make sure we -- we explain this, because a lot of people are convinced otherwise.

This -- this data suggests that, faced with a drought, the alternatives are the same, which is not what most people believe.

MS. LIZ CARRIERE: In this scenario, where the drought is between '21/'22 to '25/'26, first -- firstly, the CT doesn't come in until about 2023, so it's not there for the entire period of time. As well, you're -- you're bringing it in to serve domestic load, so it's -- the entire amount of the plant is not available just to serve -- to replace -- displace energy from the hydro generating stations, and -- but there are still -- it's still -- it's not enough to -- to supply the reduction in the -- in energy produced by all of the other generating stations on the hydroelectric system.

ED WOJCZYNSKI, Previously Sworn

CONTINUED BY MS. MARLA BOYD:

MS. MARLA BOYD: You did well, Mr.

Chairman. We've brought Mr. Wojczynski back.

MR. ED WOJCZYNSKI: So much for vacation. That -- that's a very good question, and I'll -- I'll try and answer it without getting into too much complication.

If you're -- when you have the gas turbine, and you're counting on it for energy during the drought period, and then instead of putting in -- in a hydro plant, as Ms. Carriere indicated, when -- the bulk of our energy in the system is still coming from -- from a hydro. You put in a -- a number of gas turbines, the vast majority of your energy most of the time is still coming from the hydro plants.

But if you add another -- if you add a gas turbine instead of the hydro, you have a -- a curve of -- of -- on your -- on your hydro curve, when Mr. Cormie and others were talking earlier, at one (1) point, I think we showed a curve where the probability of having to use imports or thermal happens, and if you put your gas turbine in, instead of a hydro, you're getting higher up the curve and increasing the amount of thermal you'd have to use and the likelihood you will have to use it.

So the -- the gas turbine, putting it in doesn't inherently increase your -- your exposure to drought given our base system, which is what Ms. Carriere was indicating. We could give you a graphical depiction of that, but I -- we don't have that handy here right now. We could give you an undertaking, if you like, given that it sounds like it's of some -- it is of some significance.

THE CHAIRPERSON: Yes, an undertaking would be appreciated, but I'll let you word it.

MR. ED WOJCZYNSKI: The undertaking would be to provide a -- a graphical explanation, along with words of why, when you add a gas generation, you still have a major exposure to drought cost? I -- I believe that would -- that -- that would be a way of putting your question, Mr. Chair?

THE CHAIRPERSON: Yes, it would be. And I think it -- you know, with particular reference to the early decision, which, in my opinion, is the Keeyask decision, so.

MR. ED WOJCZYNSKI: Yeah, so we'll do it, not from the point of view of at the end of the sequence, but at an early point in time, and we could use something like the '25/'26 time frame. But as Ms. Carriere indicated, there is a bit of -- this is a awkward time to deal with, because it -- your gas turbines's only coming in halfway through. So we'll probably give something that's a little bit more simple, where it's at the end of the time period when it's fully in, so that we get the full impact of that first gas turbine. Thank you.

THE CHAIRPERSON: Thank you.

--- UNDERTAKING NO. 46: Manitoba Hydro to provide a graphical and textual explanation of why, when adding a gas generation, there is still a major exposure to drought cost

MR. MANFRED SCHULZ: And now to, as Mr. Rainkie says, bat clean-up, using the baseball term, I'll continue on with the financial risk management and bring the presentation to a close. The next slide, number 70, indicating that the risk management is integral to the NFAT submission. Manitoba Hydro considers business risk as an integral aspect of its plans and operations.

And Manitoba Hydro's financial risks, forecasts, ratios, evaluations have been extensively examined, as Ms. Carriere has indicated in Chapter 11 and Appendix 11.4, two-hundred and sixteen (216) distinct set of pro forma financial statements.

And the financial volatility of severe drought was also examined in the NFAT filing, for instance in Section 11.4. Ms. Carriere just spoke a little bit about that, as well. And the submission also includes flexible pathways to manage through future uncertainties, as well.

Moving to the next slide, financial risk is manageable and the debt is self-supporting. Manitoba Hydro, as Mr. Rainkie has indicated a number of times already today, is embarking upon its development plans from a position of strength. And as measured by the equity ratio, the Corporation is well situated to move forward with its upcoming capital investments.

The next slide -- and my son would probably laugh at me and call me a bit of a math nerd for trying to tell the history of Manitoba Hydro through sort of a numerical equity ratio, but perhaps if I can. Again, this is a little bit for context, much like Mr. Barnlund provided some context on the rates, if I can spend a moment or two (2) on the context of the equity ratio.

So looking at this from 1962 and then the first phase of that northern development with Grand

Rapids, Kettle, Jenpeg, and Long Spruce, you can see the equity ratio was sub 10 percent, and it moved downward through that period up to 1978, where the equity ratio was below 5 percent, in around 3 percent, for instance.

Then the next period which we defined on this chart as being the Period of Improvements in Service and Reliability, as well as the construction of Limestone. You see some plateauing and some choppiness in here. You see a little bit of an attempt moving upward in terms of a return, and then we have some hydrology years where there was poor hydrology. Nonetheless, somewhat plateauing in and around 10 -- or 5 percent in terms of the equity ratio.

Then the next phase occurs when Limestone is in, and this major part of the northern development is in. You see this very significant upward movement in the equity ratio post-Limestone, and this is the period of returns, surplus energy, development of the export markets, and so forth. You see the equity ratio moving forth very significantly and far surpassing the levels where the equity ratio -- ratio was at the beginning of this northern development.

You see a movement downward. That's the

drought and recovery period momentarily for -- with respect to the -- the drought in '03/'04, but it also included the time frame of MISO Day 2, as well as the construction -- the planning and construction of Wuskwatim.

So then you see at the -- the top part of the blue, the historical aspect to -- with respect to what Mr. Rainkie has numerously indicated. We are in the strongest financial position in the history of the Corporation, as told by the equity ratio. And this is an excellent position to be well situated to move forward.

As we do move forward, and you can see this in the green bars on the far right, is the equity ratio in our plans. This is in IFF13, and this includes Keeyask and Conawapa. So once again you see the pattern of the movement downward during the -- the period of investments, and then you see here graphically depicted, as well, the period of returns. Ms. Carriere, in her slide number 60, also indicated in that line chart, as well, the extension of the -- the equity ratio through the forecast period, as well.

What you do see here is a number of observations, is the observation of periods of investment followed by returns. That's something that's been in the nomenclature for Manitoba Hydro now for a number of years. It's real. It has happened in the past. It's certainly part of our forecast, that you will see that moving forward.

If you look at the northern development period starting in -- start the equity ratio and the movement down on that, it took approximately thirty (30) years for the recovery period to come back. So if you look at 1966 to a period of 1996, if you draw a line across, it took about thirty (30) years approximately for the equity ratio to return back to where it started.

Where are we now? Fast-forward to the future. You see in the green bars we're looking at something that's approaching twenty (20) to twenty-five (25) years. So, Dr. Grant, further to your question about how far can you stretch the -- the equity ratio and what would be appropriate, what we've seen here historically it's something that approaches thirty (30) years.

So that -- that's part of what we are -- are looking at. But we would like, from a financial risk perspective, if at all possible, to bring it into a tighter bandwidth, just because of the uncertainties.

The other question becomes: How low can

you go? So in the forecast period, you see that in the green bars as part of the IFF13. You're seeing that the equity ratio sort of flattens out at around 11 percent. If you look historically through the period of the northern development, which also had some droughts, you're seeing it actually move quite a bit below that period, what we're looking at now, and down to below 5 percent.

We see as -- Mr. Chairman, you see the equity ratios being a bit of a buffer and a cushion. We see that as well. Again, these are all based on average water flows and so on, so we always need to be mindful of changing conditions. And -- and Ms. Carriere and others will have spoke to that, as well as other panels.

So as we move forward there's always going to be changing conditions, but we need to be mindful of it. But we want to have some shock absorption to be able to -- to make sure that we can rebound quickly, should there be any kind of drought-type situations, or other capital cost movements, or other kind of adverse situations. That's the equity ratio as told through our history at Manitoba Hydro.

The next slide, slide 73, with respect to Manitoba Hydro's borrowings, the Corporation receives a flowthrough credit from the Province of Manitoba. And in exchange for this flowthrough credit and borrowing capability, Manitoba Hydro pays a provincial debt guarantee fee to the Province of Manitoba that's equal to 1 percent of the applicable debt that's guaranteed. So we look at the amount that's at March 31 and we apply 1 percent to that.

And as Manitoba Hydro makes interest and principal payments to bond holders on an uninterrupted basis, the debt is guaranteed by the credit rate -- was considered by the cre -- credit-rating agencies to be self-supporting. And therefore, and a fairly important comment, to the extent that Manitoba Hydro prudently manages its debt, and we believe that we do, and we maintain a self-supporting status, Manitoba Hydro's Capital Investment Plan should have no significant impact on the Province of Manitoba's credit rating.

So in terms of the debt management strategy, just a few words on this. Manitoba Hydro's fundamental debt management objective is to do two (2) things. One (1) is to be stable and to provide low-cost funding to meet the financial obligations and liquidity needs of the Corporation. Manitoba Hydro's actual -- move to the next...

Manitoba Hydro's actual long-term

financings includes debt issuance in various terms to maturity. And in order to mitigate the refinancing risk, Manitoba Hydro will match long-lived assets with long-term debt. Long-term assets, Ms. Carriere indicated on -- on the Hydro side we look at it from up to one hundred (100) plus years. And so we want to have the matching of that with long-term debt as well. And so as a debt management strategy Manitoba Hydro will continue to favour long-term fixed rate financings with maturities that are ten (10) plus years long.

So what does that mean in terms of our actual performance? A little bit of a time lapse historically. In terms of the low-cost dimension of this, when looking at the debt portfolio and the weighted average interest rates at -- at fiscal year ending for each of these years, you can see -- taking advantage of the low interest rate environment we've been able to fairly successfully move the -- the weighted average interest rate on the portfolio down.

So, for instance, from 2006 and '07 where it was nearly at 8 percent, we are looking at '13/'14 to be in and around 6 percent. So a reduction in the weighted average interest rates on the portfolio by 2 percent, a fairly significant amount. The forecast moving forward is for that to -- to be going down, continuing. We don't know how long the interest rate environment is going to stay low, but while we've been here we've been doing our best to make sure that we can bring that portfolio cost down.

Also, very important, though -- and -- and I think in the context of the NFAT is the notion of stability. So it's not just the low interest rates today, but -- but what's it going to be like moving forward. So when we look at what is the weighted average term to maturity for our long-term debt.

We have been taking actions during this period of them, not only to reduce the interest rate, but to extend the period of time to reduce the refinancing risk. And so when you're looking at the period of time and performance on this from 2006/'07, where the weighted average term to maturity was in around thirteen (13) years, now we're going to be over sixteen (16) years. So we've increased that by a full three (3) years.

When looking at what we've done, for instance, in the last year, in the fiscal year that we're currently in, or approaching to its conclusion in '13/'14, the terms to maturity that we've undertaken have ranged from three (3) to fifty (50) years. And the weighted average of the new issuance that we've had is twenty-eight (28) years.

So I want to sort of take a point on that, that we've actually undertaken ultra-long financings. In fact, the last piece of financing that we took at Manitoba Hydro was a fifty (50) year piece of financing that took us to maturity at 2063.

So not only are we taking advantage of low interest rates -- and that interest rate on that particular piece of financing I think was around 3.87 percent, not including the provincial debt guarantee fee; a very, very low interest rate taking advantage of this and having that over an extended period of time. So there's no refinancing points along the way, so reducing the interest rate risk.

So by undertaking these measures and looking at that administrative environment we are able to reduce the cost and achieve higher stability.

Moving on perhaps just to cover off some other risks. Foreign currency exchange risk, they're some -- to me, a little bit odd in terms of the confusion. Sometimes there seems to be a thought that there's a great foreign currency exchange risk between our export revenues that are denominated in US dollars and where we are in Canada and are we fluctuating and -- and vulnerable to that.

Manitoba Hydro's net income is largely inoculated from the fluctuations in the US/CAD rate. And Manitoba Hydro has significant export revenues and cash inflows denominated in US dollars. However, and the next bullet indicates this, in order to maintain and manage the foreign currency risk on these revenues, Manitoba Hydro maintains a natural hedge.

So -- and I don't want to belabour the point because I certainly would love to speak on this for hours, but if I can just spend thirty (30) seconds on this. We have revenues that come up in US dollars to the extent that we have a natural hedge and have US dollar outflows that manage the inflows, that the exposure is just on the net difference.

And so if the US/CAD rate goes up and down, the exposure level remains the same. And so as a consequence of this, foreign currency risk in our financial statements, when you look at both the revenues as well as the offset that occurs on the expense side primarily through finance expense, you see that they balance one another out such that there's a general inoculation towards foreign currency as a risk for the Corporation.

Moving forward in terms of liquidity risk. Liquidity risk, just to define that, is --

refers to the risk that Manitoba Hydro will not have sufficient cash or cash equivalents to meet its financial obligations as they come due.

And Manitoba Hydro will meet its financial obligations when due through: cash generated from operations, number 1; number 2, short-term borrowings; 3) long-term borrowings; and, where applicable, sinking fund withdrawals.

And Manitoba Hydro can issue short-term borrowings in the name of the Manitoba Hydroelectric board up to a limit of $500 million. So that's -- in effect, what we have is -- you can think of it almost like an overdraft in terms of how much we have as our short-term borrowing capability.

The next slide, just sort of to build upon some of the discussion on risk, while there's a discussion of risk about what it does for our financials in the accounting, I just want to just briefly touch on this from a cash perspective.

And so during a severe prolonged drought, Manitoba Hydro will -- would provide sufficient cashflows for the continuity of business operations. I mean, we're going to continue to have business as usual for Manitoba Hydro. That's what happened in '03/'04. And Manitoba Hydro's debt will remain to be self-supporting.

So what measures would we undertake? There's three (3) measures, and we would use them in some combination of -- and we talk about it generally here, but the first one is cash conservation. So Manitoba Hydro would curtail or delay its operating and capital expenditures as required and as appropriate. And in severe circumstances, this may include exercising the optionality available within the development plans.

But our first approach would be to see what can we do, just -- and as any homeowner, any person would do when faced with a situation, we would see what can we do maybe not to have as many cash outflows. And we would certainly and we would do that, and we have done it and we would continue to do that.

The second piece to this is bridge financing. I've already indicated that we have our $500 million short-term borrowing program; or, alternatively, could access the capital markets for shorter-dated debt. You know, could be one (1) year, two (2) year, three (3) years, such that they could be retired upon resumption of positive cashflow from operations.

And thirdly, increase the cash inflows

through rate increases. And should circumstances warrant, Manitoba Hydro could apply for higher rate increases in order to generate additional cashflows.

So the view from the credit-rating agencies is also important to this because you will hear about what we believe and what we think. But what did the credit-rating agencies have to say to this? And as treasurer, I have been involved in the credit-rating agency discussions for the entire time that I've been in this post since 2008, and have had the personal conversations with these folks.

And this is a quote from DBRS, Dominion Bond Rating Service, on their report on Manitoba Hydro in September of 2013. And this, I think, is also in the book of documents; and it may be part of the cross-examination from Mr. Peters later on today. But this is from that report. This is -- indicate, actually, is one of their rating strengths for Manitoba Hydro, and again for the -- the conversation we've heard:

> "Low-cost hydro-based generation -- low-cost hydro-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its

"...domestic customers..."

And this is highlighted. This is my highlighting:

"...at one of the lowest rates on the continent."

That's further to the comments that Mr. Barnlund had made:

"And this gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened future capital expenditure requirements."

What else is coming up? So the next slide shows what Moody's has to say. So this is Moody's credit-rating agency on their report on the Province of Manitoba, dated July 23rd of 2013. Highlighting was added by Hydro. And in this section on page 3 of this report they indicate:

"Significant borrowings for Manitoba Hydro, but self-supporting. Roughly one-third (1/3) of the province's total debt and indirect debt is attributable to Hydro, but it is considered to be self-supporting by the credit-rating agencies."

And:

"This Crown corporation's -- Manitoba Hydro's ability to meet its own financial obligations without recourse to the province and subsidies is a positive credit attribute to the province."

In highlighting here:

"In our view the likelihood that the contingent liability represented by Manitoba Hydro's debt would ever materialize remains relatively remote."

And then, finally, a fairly long quote, and I won't necessarily read the whole thing out. You can certainly do this. This is from Moody's credit-rating report dated September 23rd of 2013, so not that long ago. And they indicate in the -- in the title of this section, which is, "Financial targets to be challenged by higher capex." And 'capex' meaning capital expenditures in this reference here. And they indicate and have a discussion about the debt management strategy and the expenditure levels.

So they are aware of the levels of expenditures we have. They see our IFFs. They're fairly sophisticated reviewers and analysts of our performance and they look at all the utilities across the country and -- and sovereign debt across the world, and so on. And they come to a conclusion, as highlighted. It's:

> "Given the uptick in capex and -- and corresponding debt, financial metrics are predicted to fall below targets."

We've demonstrated that, and that seems entirely logical. However, and I'll come to the highlighting:

> "We view Manitoba Hydro as being capable of prudently managing debt and mitigating such risk by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation."

So the view from the credit-rating agencies is, yes, they see the challenges that are in front of us. We see them, too. However, we are moving forward and they still deem us to be prudently managing the portfolio. And they see no reason to think that we would be anything other than self-supporting moving forward.

So in summary, on the financial risk

summary, there is three (3) of them that I want to highlight. Firstly, Manitoba Hydro considers business risk as a integral aspect of its plans and operations. Secondly, Manitoba Hydro's financial risk is manageable. And thirdly and finally, Manitoba Hydro will continue to take appropriate actions to ensure its debt remains self-supporting.

And so with that I bring to a conclusion the formal piece of the direct evidence brought forth by the finance panel. Open ourselves to any questions we may have on this section or anything else. Thank you.

THE CHAIRPERSON: I have a few questions. In respect of slide 73 there is -- you mentioned a provincial debt guarantee fee, which is 1 percent.

That fee has been in place for how long?

MR. MANFRED SCHULZ: There is an IR that was provided in response, I think, to MPA. I don't have it immediately at hand. But the provincial debt guarantee fee, either in that name or some other variation of a name, went back into -- I think into the 1960s. At that time I think it was one-quarter (1/4) of 1 percent and it's moved forward. I think it's been at 1 percent since 2006.

THE CHAIRPERSON: Now, the spread between the provincial borrowing interest rate that would apply in case of a -- direct provincial borrowing versus Manitoba Hydro going directly to the marketplace and being able to borrow on its own without reference to the provincial government, I mean, that would be speculative, but can we compare that to -- can we look at other utilities in Canada and say, What are they paying for their debt relative to what the provincial government -- the appropriate provincial government is paying?

Now, I think we heard some evidence earlier that it ranges -- it ranges, but do you know what that spread is? You know, an example of some spreads between the rate the provincial government is paying versus what the utility is paying?

MR. MANFRED SCHULZ: There's an air of speculation. There's also an air of analytics that would have to go into that, so part of -- and I don't know if it's speculation, but, you know, what would the credit rating of Manitoba Hydro be if it didn't have the self-supporting credit rating and flow through capability if we were our own operation and we were on our own?

Hard to assess that based on where we

are now, but if we were to assume that we would be investment-grade, and then, in that case, if you're looking at what some of the other private utilities might be having, you would see something that would range depending on the term. Near-term and the shorter term, there wouldn't be as much of a spread, but in the longer term, there would be a spread that would be -- it could range up to three (3) and four hundred (400) basis points, depending on the financial strength of that entity you're trying to compare it to, or where we would be.

So certainly not wanting to sort of say with any kind of definitive air, Mr. Chairman, what that amount would be, and it's not just as well the interest rate. It's also the liquidity. So being part of the province is not just about interest rates and what the spread is. It's also the borrowing capability to take on longer pieces of debt because of the -- the guarantee that's provided by the province.

And so the combination of all of those things, if you're looking at what's the value of the 1 percent, is that a good value for Manitoba Hydro? I think the answer is that it's a fair exchange.

MR. DARREN RAINKIE: Mr. Chairman, I just wanted to add one (1) other thing, and Mr.

Schulz's testimony remind -- reminds me of something back in my past, and it's not only about the rate, but it's about the ability to borrow and the covenants that come with borrowing.

And in the old Centra Gas days, if we didn't have two (2) times interest coverage, we couldn't borrow a dime, so we often talk about the rate, but part of being part of the provincial apparatus, if you like, in terms of financing, and the flow through of the credit rating, and paying the -- the 1 percent fee, is that we don't have any of those types of covenants in our -- in our debt, and that's a very important thing that's often missed, I think.

MR. MANFRED SCHULZ: And if, for instance, we were to be on our own, our debt-equity ratio, then, it's coming to the point, perhaps, that Dr. Grant had made, our debt-equity ratio would need to be far stronger in terms of being able to access the liquidity that Mr. Rainkie just spoke to.

And -- and another clear example of that was when we had the economic downturn in 2008. For all intents and purposes, there was no break in continuity when Lehman Brothers went bankrupt and all the challenges that were had there. There was no real liquidity challenge that was faced, other than the one

(1) or two (2) days where everybody was sort of
scratching their head.

Manitoba Hydro and the provinces and the sovereigns were one of the earlier ones to be able to readily access the market straightaway. So it's not just about interest rates. It's also about the access to the liquidity and cash, and -- and again, I think that the provincial debt guarantee fee is a fair and reasonable exchange for that.

(BRIEF PAUSE)

THE CHAIRPERSON: Now, one of the issues that -- one of the ways in which you will -- you -- you indicated that was open to Manitoba Hydro to use in case of a liquidity issue was to use certain borrowing -- long-term borrowing, and where applicable, sinking fund withdrawals. Could you provide a little bit more detail about that?

MR. MANFRED SCHULZ: So the typical ways we would deal with this, first of all, is just cash flow from operation, short term borrowings, long term borrowings. As part of our sinking fund requirements as mando -- mandated by the Manitoba Hydro Act, we have to make contributions into the sinking fund at 1 percent of our gross debt levels plus 4 percent of whatever balance there is in the sinking fund at that time at March 31, and that's the contribution we make forward.

The typical approach is for us is that that money, which then gets invested in high quality bonds and so on with the Province of Manitoba, is that the withdrawals out of that are for debt retirement that are slated and scheduled against that.

So the intention is for the cash to be drawn out in accordance with any debt that might be retiring at that point in time, so that's where we were saying, "Where applicable," depending on where -- what debt might be coming forth.

THE CHAIRPERSON: Now, the last drought -- I'm looking at the slide 79. The last drought, '03 -- the last -- last drought, '03/'04, you used which measures to address that drought? Which of these measures were used in '03/'04? Do -- do -- were you there at the time, or?

MR. MANFRED SCHULZ: I was not at Manitoba Hydro at that time, so I wasn't privy to the pleasures of that entire endeavour, but it's my understanding that all of those would be used. And -- and, for instance, cash conservation is a natural thing. That would be the first approach. That certainly was used. There was bridge financing that did occur, so there was a -- a slight movement forward, and we -- on the $500 million short-term borrowing line, I think we were getting close to the top levels of that, at which point, then, we converted it to long-term debt, and were able to sort of replenish our -- our overdraft limit, if you will.

So that certainly did happen. In terms of rate increases, it's my understanding that there was an application moving forward in -- to receive some additional increase at that time.

THE CHAIRPERSON: Could you remind us the kinds of rate increases were applied, or does somebody remember what the rate increases were at the time that were applied? Rate increases to -- to repairs.

MR. DARREN RAINKIE: Mr. Chair, there's a tab in Mr. Peters' book of documents, I think, that quantifies the financial impact of rate increases over the last ten (10) years, and I think the percentages are -- are included in that. If I can source that, I could answer your question. My memory is getting bad. When I do a new IFF, I tend to forget about the last one. When I do a new application I -- well, I don't

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PUB MFR 10

Financial Information

A 20 year IFF for electric operations only, indicating the financial ratios (including both interest coverage ratios under EBIT and EBITDA.) [Appendix 3.4, 2015/16 GRA]. Please compare and contrast Manitoba Hydro's latest IFF with IFF15.

The MH16 20 Year Outlook can be found in Appendix 3.3 of the Application.

There are a number of significant changes in Manitoba Hydro's current financial plan (MH16) compared to its previous financial plan (MH15). These changes include:

- MH16 reflects a deterioration of the expectations for domestic load growth. As a result, the domestic revenue forecast is 5% lower at current approved rates.
- Net extra provincial revenues has decreased by 17% or $700 million in MH16 over the forecast period 2017 to 2027 driven by a 21 month delay in the in-service date of the Keeyask Generating System project as well as a 20% reduction in forecast opportunity export prices.
- MH16's capital and DSM expenditure forecast is $2.5 billion higher compared to MH15.
- Manitoba Hydro has undertaken an accelerated cost reduction program in an effort to mitigate impacts of the above changes on revenue requirement and is reflected in the MH16 forecast.
- MH16 reflects strategy that shortens the weighted average term to maturity of new debt issuance to 12 years from 20 years. As well, the forecasted interest rates for MH16 are lower than those projected in MH15.
- MH16's projected rate increases have increased to 7.90% from 2017/18 to 2021/22, followed by 2.0% thereafter compared to MH15's 3.95% to 2029.
- The amortization of the BPIII Reserve account in MH16 has been moved to the BPIII Reserve Account line in Domestic Revenues as opposed to Other Revenue in MH15.
- The $380M in unamortized balance of the Conawapa Generating System is expensed in Other Expenses and is then deferred and amortized through Net Movement in accordance with IFRS standards relating to regulatory deferrals. The appropriate accounting treatment of this unamortized balance was not yet established in MH15 and therefore it was not recognized in Other Expenses and Net Movement.

- MH16 contains the financial reporting implications of PUB Order 73/15 including the establishment of a regulated deferral account balance pertaining to $20 million per year in ineligible overhead and the difference between the Equal Life Group (ELG) and Average Service Life (ASL) depreciation methodologies.

A more comprehensive discussion and analysis of these changes can be found in Tab 3, Figure 3.4 and Appendix 3.1 – Integrated Financial Forecast IFF16.

PUB MFR 10 (Updated)
Financial Information

A 20 year IFF for electric operations only, indicating the financial ratios (including both interest coverage ratios under EBIT and EBITDA.) [Appendix 3.4, 2015/16 GRA]. Please compare and contrast Manitoba Hydro's latest IFF with IFF15.

The response to PUB MFR 10 has been updated to reflect the July 2017 update to the financial forecast for electric operations (MH16 Update).

The MH16 Update 20 Year Outlook can be found in Appendix 3.6 of the Application.

There are a number of significant changes in Manitoba Hydro's current financial plan (MH16 Update) compared to its previous financial plan (MH15). These changes include:

- MH16 Update reflects a deterioration of the expectations for domestic load growth. As a result, the domestic revenue forecast is 5.5% lower at approved and MH15 proposed 3.95% rates.
- Net extra provincial revenues has decreased by 19% or $879 million in the MH16 Update over the forecast period 2018 to 2027 driven by a 21 month delay in the in-service date of the Keeyask Generating System project as well as an approximately 27% reduction in forecast opportunity export prices.
- MH16 Update's capital and DSM expenditure forecast is $2.5 billion higher compared to MH15.
- Manitoba Hydro has undertaken an accelerated cost reduction program in an effort to mitigate impacts of the above changes on revenue requirement and is reflected in the MH16 Update forecast.
- MH16 Update reflects strategy that shortens the weighted average term to maturity of new debt issuance to 12 years from 20 years. As well, the forecasted interest rates for MH16 Update are lower than those projected in MH15.
- MH16 Update's projected rate increases have increased to 7.90% from 2017/18 to 2021/22, followed by 2.0% thereafter compared to MH15's 3.95% to 2028/29.
- The amortization of the BPIII Reserve account in MH16 Update has been moved to the BPIII Reserve Account line in Domestic Revenues as opposed to Other Revenue in MH15.

- The $380M in unamortized balance of the Conawapa Generating System is expensed in Other Expenses and is then deferred and amortized through Net Movement in accordance with IFRS standards relating to regulatory deferrals. The appropriate accounting treatment of this unamortized balance was not yet established in MH15 and therefore it was not recognized in Other Expenses and Net Movement.
- MH16 Update contains the financial reporting implications of PUB Order 73/15 including the establishment of a regulated deferral account balance pertaining to $20 million per year in ineligible overhead and the difference between the Equal Life Group (ELG) and Average Service Life (ASL) depreciation methodologies.

PUB MFR 10
(Updated) Financial Information

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- The amortization of the BPIII Reserve account in MH16 Update has been moved to the BPIII Reserve Account line in Domestic Revenues as opposed to Other Revenue

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- The $380M in unamortized balance of the Conawapa Generating System is expensed in Other Expenses and is then deferred and amortized through Net Movement in accordance with IFRS standards relating to regulatory deferrals. The appropriate accounting treatment of this unamortized balance was not yet established in MH15 and therefore it was not recognized in Other Expenses and Net Movement.

- MH16 Update contains the financial reporting implications of PUB Order 73/15 including the establishment of a regulated deferral account balance pertaining to $20 million per year in ineligible overhead and the difference between the Equal Life Group (ELG) and Average Service Life (ASL) depreciation methodologies.

~~A more comprehensive discussion and analysis of these changes can be found in Tab 3, Figure 3.4 and Appendix 3.1 – Integrated Financial Forecast IFF16.~~

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ELECTRIC OPERATIONS (MH16 20 Year Outlook at MH15 Projected Rate Increases)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
REVENUES											
Domestic Revenue											
at approved rates	1,517	1,569	1,561	1,552	1,551	1,552	1,559	1,567	1,577	1,584	1,593
additional*	-	44	125	191	260	331	408	488	573	661	753
BPIII Reserve Account	(96)	(116)	11	70	70	70	70	23	-	-	-
Extraprovincial	468	454	432	455	578	696	795	818	844	707	714
Other	27	30	31	31	33	33	34	34	35	35	36
	1,915	1,981	2,160	2,300	2,491	2,682	2,865	2,930	3,028	2,987	3,095
EXPENSES											
Operating and Administrative	535	518	501	511	513	524	536	548	559	571	583
Finance Expense	613	574	664	731	794	864	1,105	1,144	1,149	1,135	1,133
Finance Income	(18)	(16)	(20)	(27)	(27)	(30)	(37)	(13)	(17)	(13)	(15)
Depreciation and Amortization	384	396	471	515	554	597	689	714	725	739	751
Water Rentals and Assessments	131	124	112	113	114	117	127	128	131	131	131
Fuel and Power Purchased	130	135	166	146	162	149	140	138	141	128	129
Capital and Other Taxes	118	132	145	154	161	165	173	173	174	174	174
Other Expenses	60	115	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1,962	1,987	2,156	2,632	2,374	2,485	2,813	2,904	2,937	2,942	2,969
Net Income before Net Movement in Reg. Deferral	(47)	(6)	4	(333)	118	197	52	27	91	44	126
Net Movement in Regulatory Deferral	69	68	106	462	69	61	40	(49)	(49)	(48)	(45)
Net Income	22	61	111	129	187	258	92	(22)	42	(4)	82
Net Income Attributable to:											
Manitoba Hydro	**34**	**70**	**112**	**127**	**182**	**250**	**83**	**(33)**	**39**	**(6)**	**79**
Non-controlling Interest	(12)	(9)	(1)	2	5	8	9	11	3	2	3
* Additional Domestic Revenue											
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%
Financial Ratios											
Equity	15%	14%	14%	13%	13%	14%	13%	13%	13%	14%	14%
EBITDA Interest Coverage	1.50	1.53	1.63	1.66	1.71	1.79	1.73	1.68	1.76	1.74	1.83
Capital Coverage	1.08	1.23	1.23	1.28	1.51	1.76	1.54	1.56	1.55	1.42	1.55

ELECTRIC OPERATIONS (MH16 20 Year Outlook at MH15 Projected Rate Increases)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1,599	1,608	1,623	1,639	1,667	1,698	1,730	1,762	1,796
additional*	849	951	1,012	1,075	1,148	1,227	1,310	1,396	1,488
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	708	721	733	744	745	743	739	732	654
Other	36	37	38	38	39	40	40	40	41
	3,193	3,316	3,405	3,497	3,600	3,707	3,819	3,931	3,979
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1,131	1,116	1,103	1,120	1,093	1,080	1,055	1,017	983
Finance Income	(19)	(22)	(16)	(16)	(16)	(17)	(20)	(21)	(23)
Depreciation and Amortization	764	775	790	804	822	840	856	871	887
Water Rentals and Assessments	131	132	132	132	133	133	133	134	134
Fuel and Power Purchased	129	131	135	145	151	159	167	178	172
Capital and Other Taxes	174	174	176	177	178	178	179	180	186
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	2	2	2	2	2	2
	2,992	3,006	3,032	3,084	3,097	3,125	3,139	3,143	3,139
Net Income before Net Movement in Reg. Deferral	201	310	374	413	502	582	680	788	840
Net Movement in Regulatory Deferral	(43)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	157	270	339	380	471	554	651	760	810
Net Income Attributable to:									
Manitoba Hydro	**154**	**265**	**332**	**371**	**461**	**542**	**638**	**745**	**794**
Non-controlling Interest	4	5	7	9	11	12	14	15	15
* Additional Domestic Revenue									
Percent Increase	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	53.13%	59.18%	62.37%	65.61%	68.93%	72.30%	75.75%	79.26%	82.85%
Financial Ratios									
Equity	15%	16%	17%	18%	20%	22%	25%	28%	31%
EBITDA Interest Coverage	1.91	2.03	2.12	2.15	2.28	2.38	2.53	2.71	2.83
Capital Coverage	1.65	1.76	1.90	1.87	2.00	2.09	2.23	2.17	2.20

ELECTRIC OPERATIONS (MH16 20 Year Outlook at MH15 Projected Rate Increases)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13,256	13,881	19,254	19,876	20,938	26,363	30,693	31,222	31,858	32,522	33,133
Accumulated Depreciation	(985)	(1,319)	(1,749)	(2,197)	(2,634)	(3,143)	(3,724)	(4,347)	(4,961)	(5,625)	(6,231)
Net Plant in Service	12,272	12,562	17,505	17,679	18,304	23,219	26,969	26,876	26,897	26,897	26,902
Construction in Progress	6,943	9,308	6,596	7,378	7,870	3,693	224	312	276	272	269
Current and Other Assets	1,721	2,065	2,296	2,458	2,140	1,801	1,597	1,589	1,757	1,717	1,742
Goodwill and Intangible Assets	270	485	725	869	1,271	1,225	1,180	1,135	1,092	1,049	1,007
Total Assets before Regulatory Deferral	21,206	24,420	27,122	28,385	29,585	29,939	29,970	29,912	30,022	29,935	29,921
Regulatory Deferral Balance	459	526	633	1,094	1,163	1,225	1,265	1,216	1,167	1,118	1,074
	21,665	24,946	27,755	29,479	30,749	31,164	31,235	31,128	31,189	31,053	30,994
LIABILITIES AND EQUITY											
Long-Term Debt	15,578	18,120	21,357	22,182	23,154	23,879	24,292	24,061	23,773	23,112	23,954
Current and Other Liabilities	3,415	3,905	3,300	4,066	4,213	3,676	3,260	3,430	3,728	4,248	3,258
Provisions	19	19	19	18	17	16	16	15	14	14	14
Deferred Revenue	444	460	486	515	537	546	556	566	577	588	599
BPIII Reserve Account	196	312	302	232	162	93	23	(0)	(0)	(0)	(0)
Retained Earnings	2,730	2,800	2,912	3,039	3,221	3,471	3,554	3,520	3,560	3,554	3,632
Accumulated Other Comprehensive Income	(761)	(714)	(665)	(616)	(600)	(560)	(509)	(508)	(507)	(506)	(506)
Total Liabilities and Equity before Regulatory Deferral	21,621	24,903	27,711	29,435	30,705	31,120	31,191	31,085	31,145	31,009	30,951
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44	44	44
	21,665	24,946	27,755	29,479	30,749	31,164	31,235	31,128	31,189	31,053	30,994

ELECTRIC OPERATIONS (MH16 20 Year Outlook at MH15 Projected Rate Increases)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33,741	34,487	35,147	35,978	36,754	37,549	38,293	39,095	40,163
Accumulated Depreciation	(6,924)	(7,621)	(8,329)	(9,059)	(9,806)	(10,595)	(11,384)	(12,186)	(12,993)
Net Plant in Service	26,817	26,866	26,817	26,919	26,948	26,955	26,909	26,909	27,170
Construction in Progress	351	313	348	258	232	224	264	319	115
Current and Other Assets	2,072	2,389	2,187	2,057	2,411	2,248	2,632	3,422	4,188
Goodwill and Intangible Assets	967	928	890	852	814	777	740	703	667
Total Assets before Regulatory Deferral	30,206	30,495	30,242	30,086	30,405	30,203	30,545	31,353	32,140
Regulatory Deferral Balance	1,030	990	955	923	892	864	836	807	777
	31,236	31,485	31,197	31,009	31,297	31,067	31,381	32,160	32,917
LIABILITIES AND EQUITY									
Long-Term Debt	24,107	20,489	19,036	20,657	20,670	20,664	20,718	20,907	20,791
Current and Other Liabilities	3,183	6,774	7,598	5,408	5,211	4,435	4,046	3,880	3,946
Provisions	14	14	14	14	14	14	14	14	14
Deferred Revenue	610	619	629	639	649	660	671	682	694
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	3,786	4,051	4,383	4,754	5,215	5,757	6,395	7,140	7,934
Accumulated Other Comprehensive Income	(506)	(506)	(506)	(506)	(506)	(506)	(506)	(506)	(506)
Total Liabilities and Equity before Regulatory Deferral	31,193	31,442	31,154	30,965	31,253	31,023	31,337	32,117	32,874
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44
	31,236	31,485	31,197	31,009	31,297	31,067	31,381	32,160	32,917

ELECTRIC OPERATIONS (MH16 20 Year Outlook at MH15 Projected Rate Increases)
PROJECTED CASH FLOW STATEMENT

(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,007	2,087	2,138	2,219	2,410	2,600	2,783	2,895	3,015	2,974	3,082
Cash Paid to Suppliers and Employees	(876)	(917)	(881)	(880)	(903)	(908)	(923)	(937)	(954)	(952)	(964)
Interest Paid	(569)	(529)	(633)	(701)	(753)	(826)	(1,067)	(1,112)	(1,120)	(1,117)	(1,104)
Interest Received	7	5	12	21	17	15	7	5	10	5	8
	569	645	635	658	771	881	800	850	952	911	1,022
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2,743	3,570	3,590	2,170	1,990	1,190	760	190	390	550	990
Sinking Fund Withdrawals	146	0	0	182	303	767	173	60	344	149	245
Retirement of Long-Term Debt	(1,030)	(330)	(1,002)	(336)	(1,278)	(1,020)	(449)	(290)	(412)	(715)	(1,178)
Other	10	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1,868	3,229	2,578	2,005	1,004	925	495	(45)	318	(21)	52
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2,609)	(3,553)	(3,015)	(2,351)	(1,742)	(1,352)	(880)	(700)	(704)	(732)	(756)
Sinking Fund Payment	(146)	(246)	(210)	(244)	(282)	(334)	(245)	(255)	(263)	(259)	(262)
Other	(68)	(51)	(55)	(44)	(128)	(91)	(84)	(83)	(83)	(80)	(79)
	(2,822)	(3,850)	(3,280)	(2,639)	(2,152)	(1,777)	(1,209)	(1,039)	(1,051)	(1,071)	(1,098)
Net Increase (Decrease) in Cash	(384)	25	(67)	24	(378)	30	86	(233)	218	(182)	(24)
Cash at Beginning of Year	944	559	584	517	541	163	193	279	46	264	83
Cash at End of Year	559	584	517	541	163	193	279	46	264	83	59

ELECTRIC OPERATIONS (MH16 20 Year Outlook at MH15 Projected Rate Increases)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
OPERATING ACTIVITIES									
Cash Receipts from Customers	3,180	3,303	3,392	3,483	3,585	3,693	3,804	3,917	3,965
Cash Paid to Suppliers and Employees	(976)	(990)	(1,007)	(1,029)	(1,050)	(1,070)	(1,093)	(1,118)	(1,131)
Interest Paid	(1,113)	(1,111)	(1,092)	(1,106)	(1,077)	(1,074)	(1,042)	(1,018)	(995)
Interest Received	16	27	12	12	10	16	22	33	37
	1,107	1,229	1,305	1,359	1,468	1,564	1,691	1,814	1,875
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	190	(20)	2,980	3,780	1,960	1,140	750	710	370
Sinking Fund Withdrawals	150	60	510	461	0	302	0	10	275
Retirement of Long-Term Debt	(150)	(50)	(3,650)	(4,386)	(2,182)	(1,960)	(1,139)	(740)	(465)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	185	(15)	(165)	(150)	(228)	(525)	(393)	(24)	175
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Sinking Fund Payment	(261)	(265)	(273)	(258)	(243)	(251)	(242)	(248)	(256)
Other	(78)	(72)	(70)	(71)	(70)	(69)	(68)	(66)	(65)
	(1,106)	(1,136)	(1,136)	(1,160)	(1,154)	(1,177)	(1,180)	(1,261)	(1,287)
Net Increase (Decrease) in Cash	186	78	4	49	86	(137)	118	529	763
Cash at Beginning of Year	59	244	322	326	375	462	324	442	971
Cash at End of Year	244	322	326	375	462	324	442	971	1,734

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	176
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	208	354	526	443	423	533	491	580
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	909	850	800	742	675	618
Finance Income	(29)	(46)	(57)	(18)	(19)	(19)	(26)	(32)	(50)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	183	184	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 894	2 892	2 888	2 878	2 833	2 818	2 792	2 762	2 714
Net Income before Net Movement in Reg. Deferral	698	801	915	1 032	1 189	1 320	1 465	1 623	1 714
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	654	761	880	999	1 158	1 292	1 437	1 595	1 684
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	650	755	873	989	1 147	1 280	1 423	1 579	1 668
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**650**	**755**	**873**	**989**	**1 147**	**1 280**	**1 423**	**1 579**	**1 668**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	654	761	880	999	1 158	1 292	1 437	1 595	1 684
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	27%	30%	33%	37%	41%	46%	52%	57%	64%
EBITDA Interest Coverage	2.48	2.65	2.85	3.09	3.45	3.79	4.25	4.86	5.52
Capital Coverage	2.39	2.47	2.68	2.71	2.93	3.08	3.25	3.16	3.23

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity	2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 824	3 630	2 359	2 041	2 278	2 625	3 629	4 069	5 509
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	31 004	31 781	30 458	30 114	30 315	30 623	31 584	32 041	33 501
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 751	14 977	14 280	13 859	13 743
Current and Other Liabilities	2 920	5 271	7 325	5 089	5 140	3 906	4 103	3 363	3 230
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7 214	7 969	8 842	9 831	10 977	12 257	13 680	15 259	16 927
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	32 010	32 747	31 389	31 012	31 183	31 463	32 395	32 824	34 254
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
Net Debt	20 197	19 357	18 386	17 327	16 094	14 725	13 200	11 587	9 877
Total Equity	7 564	8 325	9 206	10 203	11 357	12 645	14 077	15 665	17 343
Equity Ratio	27%	30%	33%	37%	41%	46%	52%	57%	64%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 087)	(1 097)
Interest Paid	(1 019)	(1 014)	(997)	(908)	(837)	(795)	(742)	(696)	(632)
Interest Received	26	51	63	20	15	22	36	49	67
	1 604	1 720	1 843	1 972	2 155	2 307	2 473	2 637	2 752
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 150	1 140	360	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(195)	(193)	(188)	(189)	(184)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 223)	(1 219)	(704)	(1 383)	(209)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	505	594	(1 229)	(41)	19	160	829	238	1 510
Cash at Beginning of Year	541	1 047	1 640	411	370	389	549	1 378	1 616
Cash at End of Year	1 047	1 640	411	370	389	549	1 378	1 616	3 126

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim and MH15 Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	116	181	247	319	392	469	552	641	735
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 184	2 263	2 463	2 670	2 826	2 859	2 944	2 909	3 024
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	829	905	1 156	1 202	1 204	1 201	1 214
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(15)	(12)	(14)	(16)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	174	175	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 404	2 531	2 865	2 959	2 996	3 009	3 052
Net Income before Net Movement in Reg. Deferral	(46)	13	33	(396)	59	139	(39)	(99)	(52)	(100)	(28)
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	147	69	130	202	3	(147)	(101)	(148)	(73)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	148	66	125	194	(6)	(158)	(105)	(151)	(76)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**148**	**66**	**125**	**194**	**(6)**	**(158)**	**(105)**	**(151)**	**(76)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	147	69	130	202	3	(147)	(101)	(148)	(73)
* Additional Domestic Revenue											
Percent Increase		3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase		3.36%	7.44%	11.69%	16.10%	20.68%	25.45%	30.41%	35.56%	40.91%	46.48%
Financial Ratios											
Equity	16%	15%	14%	14%	14%	14%	13%	13%	12%	12%	12%
EBITDA Interest Coverage	1.51	1.54	1.64	1.59	1.64	1.72	1.62	1.55	1.61	1.58	1.65
Capital Coverage	1.53	1.40	1.36	1.20	1.45	1.70	1.41	1.33	1.31	1.21	1.31

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim and MH15 Rate Increases
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	835	940	1 001	1 065	1 137	1 213	1 291	1 374	1 460
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 133	3 269	3 366	3 460	3 555	3 654	3 756	3 865	3 889
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 219	1 206	1 194	1 215	1 200	1 197	1 183	1 155	1 128
Finance Income	(17)	(16)	(16)	(15)	(17)	(17)	(21)	(22)	(23)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 087	3 108	3 128	3 186	3 185	3 216	3 237	3 251	3 250
Net Income before Net Movement in Reg. Deferral	46	161	238	273	370	438	519	614	639
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	2	121	203	241	339	410	490	585	609
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	(2)	115	195	231	328	397	476	570	593
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**(2)**	**115**	**195**	**231**	**328**	**397**	**476**	**570**	**593**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	2	121	203	241	339	410	490	585	609
* Additional Domestic Revenue									
Percent Increase	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	52.26%	58.28%	61.44%	64.67%	67.97%	71.33%	74.75%	78.25%	81.81%
Financial Ratios									
Equity	12%	12%	13%	14%	15%	17%	19%	21%	23%
EBITDA Interest Coverage	1.72	1.83	1.92	1.94	2.05	2.13	2.23	2.35	2.42
Capital Coverage	1.43	1.55	1.70	1.68	1.82	1.90	2.01	1.96	1.97

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim and MH15 Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 205	2 496	2 547	1 803	1 597	1 648	1 659	1 879	1 743
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 063	28 450	30 039	29 983	30 018	30 019	29 971	30 143	29 968
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 710	29 562	31 221	31 229	31 307	31 260	31 162	31 286	31 066
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 668	24 547	24 259	23 998	24 840
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 151	3 033	3 192	3 476	4 001	3 005
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 990	3 056	3 181	3 375	3 368	3 210	3 106	2 955	2 879
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(351)	(350)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 662	29 513	31 173	31 180	31 258	31 211	31 113	31 237	31 017
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 710	29 562	31 221	31 229	31 307	31 260	31 162	31 286	31 066
Net Debt	15 427	18 473	20 806	22 609	23 717	24 349	24 557	24 547	24 547	24 595	24 577
Total Equity	2 856	3 163	3 447	3 567	3 718	3 916	3 600	3 529	3 439	3 302	3 240
Equity Ratio	16%	15%	14%	14%	14%	14%	13%	13%	12%	12%	12%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim and MH15 Rate Increases
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 123	2 289	2 140	2 071	2 492	2 358	3 030	3 483	4 446
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 303	30 440	30 240	30 144	30 530	30 355	30 985	31 456	32 439
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	31 357	31 454	31 220	31 091	31 446	31 244	31 845	32 287	33 240
LIABILITIES AND EQUITY									
Long-Term Debt	25 172	22 795	20 302	21 962	21 926	22 563	22 280	22 859	23 343
Current and Other Liabilities	2 956	5 307	7 361	5 332	5 386	4 140	4 539	3 821	3 687
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	2 877	2 992	3 187	3 418	3 746	4 143	4 619	5 189	5 783
Accumulated Other Comprehensive Income	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	31 308	31 406	31 171	31 042	31 397	31 195	31 796	32 238	33 192
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 357	31 454	31 220	31 091	31 446	31 244	31 845	32 287	33 240
Net Debt	24 472	24 273	23 979	23 671	23 254	22 767	22 185	21 572	20 940
Total Equity	3 253	3 374	3 577	3 816	4 152	4 557	5 042	5 621	6 224
Equity Ratio	12%	12%	13%	14%	15%	17%	19%	21%	23%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim and MH15 Rate Increases
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 170	2 173	2 371	2 577	2 734	2 821	2 931	2 897	3 011
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(903)	(935)	(953)	(952)	(966)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(853)	(1 102)	(1 170)	(1 178)	(1 178)	(1 191)
Interest Received	17	5	11	22	26	19	7	6	6	6	9
	810	734	703	621	742	850	736	722	807	773	863
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 560	390	390	950	990
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	348	153	250
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(259)	(268)	(264)	(271)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 861	1 108	273	366	(111)	53	119	(213)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	10	44	(0)	(354)	105	(185)	60	78	(188)
Cash at Beginning of Year	943	634	488	498	543	542	188	292	107	167	245
Cash at End of Year	634	488	498	543	542	188	292	107	167	245	57

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim and MH15 Rate Increases
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 120	3 255	3 352	3 446	3 540	3 640	3 741	3 851	3 874
Cash Paid to Suppliers and Employees	(980)	(995)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 086)	(1 096)
Interest Paid	(1 195)	(1 203)	(1 198)	(1 205)	(1 184)	(1 195)	(1 178)	(1 167)	(1 148)
Interest Received	15	23	24	15	13	23	28	40	44
	959	1 080	1 166	1 221	1 339	1 425	1 529	1 637	1 675
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	(10)	1 970	3 990	2 350	1 740	1 160	1 300	970
Sinking Fund Withdrawals	150	60	502	520	0	230	43	10	275
Sinking Fund Payment	(270)	(277)	(283)	(270)	(258)	(268)	(265)	(273)	(282)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 096)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	115	(292)	(256)	(161)	(286)	(695)	(162)	(454)	294
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	226	(85)	46	155	140	(197)	428	168	935
Cash at Beginning of Year	57	283	199	245	400	540	342	770	938
Cash at End of Year	283	199	245	400	540	342	770	938	1 873

REFERENCE:

Appendix 3.8; PUB MFR 72 Attachment Page 195 of 615

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an alternative scenario IFF16 Update with Interim based on a 32 month delay in Keeyask, as suggested may be plausible by BCG.

b) Please provide an alternative scenario IFF16 Update with Interim based on a 32 month delay in Keeyask, as suggested may be plausible by BCG, but based on the P90 Keeyask cost estimate.

RATIONALE FOR QUESTION:

RESPONSE:

Public disclosure of portions of this information request would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

a) The work required to undertake a Keeyask 32-month delay scenario under both a P50 and P90 capital cost estimate is significant. In order to complete the response within the prescribed timeline, the PUB agreed to Manitoba Hydro providing only an IFF scenario that assumes the 32 month delay for Keeyask at the P90 cost estimate, as requested in part b).

b) Please see the following projected financial statements for MH16 Update with Interim reflecting a 32-month delay in Keeyask based on a P90 Keeyask cost estimate. The 32-month delay scenario assumes an additional 11-month delay as compared to MH16 Update with Interim. The requested scenario assumes an in-service date of July 2022 which is an 11-month delay from the current estimate of August 2021 (as shown in MH16 Update with Interim) and a 32-month delay from the previous target in-service date of November 2019. For this analysis, the budget has been increased by $1.2 billion from $8.7 billion in MH16 Update with Interim to $9.9 billion. The 32-month delay scenario assumes a revision to the original amounts carried for risk (contingency) in the capital project justification addendum ($8.7B). The contingency in the $8.7B budget was based on a P50 level, whereas this scenario assumes a P90 level and the amount carried is based on the recommended value from an external consultant.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Keeyask 32-Month Delay (P90) for PUB/MH II-25b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	[redacted]			805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	[redacted]			3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	515	531	548	559	571	583
Finance Expense	608	588	677	745	817	807	876	1 142	1 151	1 124	1 099
Finance Income	(17)	(17)	(21)	(29)	(35)	(34)	(40)	(39)	(16)	(18)	(21)
Depreciation and Amortization	375	396	471	515	555	574	615	719	742	755	768
Water Rentals and Assessments	131	130	120	110	113	113	118	127	128	131	131
Fuel and Power Purchased	132	124	140	158	165	[redacted]					
Capital and Other Taxes	119	132	145	154	161	167	172	180	181	180	181
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 996	2 150	2 655	2 392	[redacted]					
Net Income before Net Movement in Reg. Deferral	(46)	12	96	(257)	282	[redacted]					
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	84	209	208	353	[redacted]					
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	92	210	205	348	[redacted]					
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	53	92	210	205	348	[redacted]					
Non-controlling Interest	(12)	(8)	(1)	2	5	9	3	11	3	2	3
	41	84	209	208	353	[redacted]					
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	16%	18%	19%	21%	22%	24%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.03	2.16	2.07	2.15	2.15	2.27
Capital Coverage	1.53	1.39	1.48	1.48	1.87	2.38	2.56	2.34	2.28	2.12	2.23

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Keeyask 32-Month Delay (P90) for PUB/MH II-25b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 088	1 070	1 041	964	910	863	803	738	704
Finance Income	(31)	(47)	(53)	(17)	(19)	(18)	(22)	(27)	(63)
Depreciation and Amortization	781	791	806	821	838	856	872	888	904
Water Rentals and Assessments	131	131	132	132	132	133	133	133	134
Fuel and Power Purchased	[redacted]								
Capital and Other Taxes	182	182	183	184	185	186	187	189	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	[redacted]								
Net Income before Net Movement in Reg. Deferral	[redacted]								
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	[redacted]								
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	[redacted]								
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	[redacted]								
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	[redacted]								
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	26%	29%	32%	35%	39%	43%	48%	54%	59%
EBITDA Interest Coverage	2.37	2.52	2.71	2.91	3.22	3.51	3.91	4.41	4.91
Capital Coverage	2.32	2.39	2.60	2.63	2.86	2.97	3.16	3.07	3.15

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Keeyask 32-Month Delay (P90) for PUB/MH II-25b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	21 235	28 747	32 190	32 826	33 490	34 101
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 102)	(3 608)	(4 235)	(4 865)	(5 546)	(6 167)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	18 133	25 139	27 955	27 960	27 944	27 934
Construction in Progress	7 079	9 615	6 926	7 640	8 113	9 111	2 924	380	421	417	414
Current and Other Assets	1 773	1 769	2 088	2 381	2 468	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 304	27 127	28 453	30 060	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 837	27 774	29 565	31 242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	23 050	24 268	23 747	23 059	21 798	22 640
Current and Other Liabilities	3 204	3 642	3 048	3 817	4 357	4 159	3 374	3 186	3 468	3 985	2 990
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 841	3 051	3 257	3 605	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(351)	(350)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 788	27 725	29 516	31 194	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 837	27 774	29 565	31 242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Debt	15 427	18 462	20 782	22 431	23 351	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Equity	2 856	3 162	3 512	3 770	4 144	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Equity Ratio	16%	15%	14%	14%	15%	16%	18%	19%	21%	22%	24%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Keeyask 32-Month Delay (P90) for PUB/MH II-25b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	34 709	35 455	36 115	36 946	37 719	38 517	39 261	40 063	41 131
Accumulated Depreciation	(6 877)	(7 590)	(8 314)	(9 059)	(9 823)	(10 627)	(11 432)	(12 250)	(13 073)
Net Plant in Service	27 832	27 865	27 801	27 887	27 896	27 891	27 829	27 813	28 058
Construction in Progress	495	457	493	403	377	369	409	464	260
Current and Other Assets	[redacted]								
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	[redacted]								
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	[redacted]								
LIABILITIES AND EQUITY									
Long-Term Debt	22 572	20 195	15 902	16 962	16 126	15 963	15 080	15 259	15 143
Current and Other Liabilities	2 935	5 286	7 340	5 104	5 156	4 103	4 495	3 366	3 233
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	[redacted]								
Accumulated Other Comprehensive Income	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	[redacted]								
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	[redacted]								
Net Debt	[redacted]								
Total Equity									
Equity Ratio	26%	29%	32%	35%	39%	43%	48%	54%	59%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Keeyask 32-Month Delay (P90) for PUB/MH II-25b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	[redacted]			3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	[redacted]					
Interest Paid	(553)	(533)	(635)	(699)	(764)	(756)	(820)	(1 114)	(1 127)	(1 109)	(1 076)
Interest Received	17	5	12	23	26	19	7	5	10	11	14
	810	733	767	761	958	[redacted]					
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	1 190	1 560	(10)	(10)	(50)	990
Sinking Fund Withdrawals	146	0	0	120	318	813	182	48	344	144	238
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(242)	(255)	(259)	(251)	(248)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	(11)	17	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	273	347	(489)	(342)	(877)	(203)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 647)	(3 052)	(2 378)	(1 789)	(1 640)	(1 460)	(861)	(782)	(732)	(757)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 736)	(3 109)	(2 424)	(1 879)	(1 748)	(1 559)	(957)	(877)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(135)	24	(2)	(12)	[redacted]					
Cash at Beginning of Year	943	634	499	523	521						
Cash at End of Year	634	499	523	521	508						

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Keeyask 32-Month Delay (P90) for PUB/MH II-25b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	[redacted]								
Interest Paid	(1 070)	(1 065)	(1 044)	(958)	(898)	(865)	(808)	(762)	(721)
Interest Received	28	52	60	14	15	22	33	46	82
	[redacted]								
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	3 190	1 350	940	560	500	(30)
Sinking Fund Withdrawals	150	60	310	565	0	30	43	10	275
Sinking Fund Payment	(247)	(249)	(256)	(232)	(206)	(206)	(202)	(202)	(200)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(1 096)	(1 487)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(262)	(264)	(2 221)	(879)	(1 034)	(1 433)	(699)	(1 184)	(225)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(837)	(861)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(909)	(932)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	[redacted]								
Cash at Beginning of Year									
Cash at End of Year									

17

REFERENCE:

PUB/MH 1-1 e)

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on the MH16 Update with the August 1st, 2017 interim increase, please provide an IFF that, based on even rate increases for the years 2018/19 through 2033/34 achieves an equity ratio of 25% by 2033/34 and uses 2% per annum thereafter. (Note: This scenario differs from PUB/MH 1-1 e) in that it will use the MH 16 Update with Interim assumptions set out on page 28 of 41).

RATIONALE FOR QUESTION:

To understand the implications of Manitoba Hydro's regulatory accounting assumptions based on the new MH16 Update with Interim.

RESPONSE:

The following projected financial statements based on MH16 Update with Interim reflect annual rate increases of 4.14% from 2018/19 through 2033/34 to achieve a 25% equity ratio by 2033/34.

Sixteen years of 4.14% rate increases generate limited net income ($47 million per year on average) over the first 12 years of the forecast scenario including a 4 year period with cumulative losses of approximately $350 million following the Keeyask in-service. Levels of income that make any material contribution to debt reduction are deferred until the last 8 years of the forecast under this scenario, a period which is inherently more uncertain than the preceding period, and relies on the preceding period being at or above average water flows and other forecast assumptions. The equity ratio under this scenario deteriorates to 12% by 2026. Even without below average water conditions or drought, adverse changes in interest rates, export prices or other factors will significantly increase necessary rate increases beyond 4.14% per annum in order to restore a 25% equity to capitalization ratio by 2033/34.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	119	187	257	333	410	491	579	673	773
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 187	2 270	2 473	2 683	2 844	2 881	2 971	2 941	3 062
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	828	904	1 155	1 196	1 202	1 196	1 204
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(38)	(12)	(14)	(15)	(16)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 403	2 530	2 864	2 955	2 992	3 003	3 042
Net Income before Net Movement in Reg. Deferral	(46)	13	36	(390)	69	153	(20)	(73)	(22)	(61)	20
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	150	75	141	217	23	(121)	(71)	(110)	(25)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	151	72	135	208	13	(132)	(74)	(112)	(28)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**151**	**72**	**135**	**208**	**13**	**(132)**	**(74)**	**(112)**	**(28)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	150	75	141	217	23	(121)	(71)	(110)	(25)
* Additional Domestic Revenue											
Percent Increase		3.36%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%
Cumulative Percent Increase		3.36%	7.64%	12.09%	16.73%	21.56%	26.59%	31.83%	37.28%	42.96%	48.88%
Financial Ratios											
Equity	16%	15%	14%	14%	14%	14%	13%	13%	13%	12%	12%
EBITDA Interest Coverage	1.51	1.54	1.65	1.59	1.65	1.73	1.64	1.57	1.63	1.62	1.69
Capital Coverage	1.53	1.40	1.37	1.22	1.47	1.73	1.45	1.37	1.36	1.28	1.39

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	880	991	1 110	1 236	1 377	1 528	1 689	1 786	1 887
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 177	3 320	3 475	3 631	3 795	3 969	4 153	4 276	4 316
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 208	1 195	1 179	1 190	1 162	1 142	1 104	1 059	1 011
Finance Income	(17)	(18)	(18)	(17)	(18)	(18)	(20)	(26)	(31)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 076	3 095	3 111	3 160	3 146	3 160	3 159	3 151	3 125
Net Income before Net Movement in Reg. Deferral	101	225	364	471	649	809	994	1 125	1 190
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	58	185	329	438	618	781	965	1 097	1 161
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	54	180	321	428	607	769	951	1 081	1 144
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**54**	**180**	**321**	**428**	**607**	**769**	**951**	**1 081**	**1 144**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	58	185	329	438	618	781	965	1 097	1 161
* Additional Domestic Revenue									
Percent Increase	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	2.00%	2.00%
Cumulative Percent Increase	55.04%	61.45%	68.13%	75.09%	82.33%	89.88%	97.73%	101.69%	105.72%
Financial Ratios									
Equity	13%	13%	15%	16%	19%	21%	25%	29%	33%
EBITDA Interest Coverage	1.77	1.89	2.04	2.13	2.33	2.51	2.74	2.96	3.15
Capital Coverage	1.51	1.64	1.88	1.95	2.20	2.40	2.63	2.57	2.61

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 208	2 505	2 567	1 836	1 648	1 723	1 564	1 633	1 748
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 067	28 460	30 058	30 016	30 070	30 094	29 876	29 897	29 973
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 713	29 571	31 240	31 262	31 358	31 335	31 068	31 040	31 071
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 668	24 547	24 059	23 598	24 640
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 150	3 031	3 188	3 472	4 007	3 014
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 993	3 065	3 201	3 409	3 422	3 290	3 215	3 103	3 075
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(351)	(350)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 665	29 522	31 192	31 213	31 309	31 286	31 019	30 991	31 022
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 713	29 571	31 240	31 262	31 358	31 335	31 068	31 040	31 071
Net Debt	15 427	18 473	20 803	22 599	23 698	24 316	24 506	24 472	24 441	24 443	24 372
Total Equity	2 856	3 163	3 450	3 577	3 737	3 951	3 654	3 608	3 549	3 450	3 436
Equity Ratio	16%	15%	14%	14%	14%	14%	13%	13%	13%	12%	12%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 184	2 414	2 395	2 119	2 419	2 453	3 195	3 755	4 270
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 363	30 565	30 494	30 192	30 456	30 451	31 149	31 728	32 262
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	31 418	31 579	31 474	31 139	31 372	31 340	32 009	32 559	33 064
LIABILITIES AND EQUITY									
Long-Term Debt	24 972	22 595	20 102	21 362	20 926	21 363	20 680	20 859	20 543
Current and Other Liabilities	2 965	5 315	7 372	5 340	5 394	4 146	4 538	3 817	3 482
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	3 129	3 308	3 630	4 058	4 665	5 433	6 385	7 466	8 610
Accumulated Other Comprehensive Income	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	31 369	31 531	31 425	31 090	31 323	31 291	31 961	32 510	33 015
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 418	31 579	31 474	31 139	31 372	31 340	32 009	32 559	33 064
Net Debt	24 212	23 948	23 525	23 023	22 327	21 471	20 421	19 300	18 116
Total Equity	3 505	3 690	4 019	4 455	5 070	5 847	6 807	7 898	9 052
Equity Ratio	13%	13%	15%	16%	19%	21%	25%	29%	33%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 173	2 179	2 381	2 591	2 752	2 843	2 958	2 929	3 049
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(952)	(966)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(852)	(1 101)	(1 166)	(1 176)	(1 165)	(1 176)
Interest Received	17	5	11	22	26	19	7	4	7	7	9
	810	734	706	628	751	864	754	746	837	819	916
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 560	390	190	750	1 190
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	348	152	249
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(259)	(267)	(263)	(268)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 861	1 108	273	366	(111)	(146)	(80)	(12)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	13	51	9	(341)	123	(162)	(109)	(76)	67
Cash at Beginning of Year	943	634	488	501	552	561	221	344	182	73	(2)
Cash at End of Year	634	488	501	552	561	221	344	182	73	(2)	64

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 164	3 306	3 461	3 617	3 781	3 955	4 138	4 262	4 301
Cash Paid to Suppliers and Employees	(980)	(995)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 086)	(1 096)
Interest Paid	(1 184)	(1 191)	(1 182)	(1 186)	(1 147)	(1 141)	(1 105)	(1 073)	(1 024)
Interest Received	15	25	28	18	14	24	27	42	45
	1 015	1 144	1 295	1 415	1 618	1 794	1 997	2 145	2 226
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	(10)	1 970	3 590	1 950	1 540	760	900	(30)
Sinking Fund Withdrawals	150	60	310	708	0	230	43	10	388
Sinking Fund Payment	(268)	(275)	(280)	(275)	(252)	(258)	(251)	(256)	(260)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 096)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	117	(290)	(446)	(378)	(680)	(885)	(548)	(837)	(571)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	284	(18)	(15)	132	25	(18)	510	292	622
Cash at Beginning of Year	64	349	331	316	448	473	455	965	1 257
Cash at End of Year	349	331	316	448	473	455	965	1 257	1 879

MIPUG MFR 5

Financial Information

If different than Manitoba Hydro's new Integrated Financial Forecast, provide electric operations-only IFF scenarios with the same accounting treatment as provided in response to Attachment 28 (Financial MFR 1 of the 2016/17 Interim Application (reflecting Board directives in Order 73/15 utilizing Average Service Life Depreciation and the continuation of the capitalization of $20 million in OM&A).

The table below compares the accounting treatment reflecting Order 73/15 in MH16 and Attachment 28 from the 2016/17 Supplemental Filing:

	MH16	Attachment 28
Ineligible Overhead		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferred Until	2022/23	Indefinite
Equal Life Group (ELG)/Average Service Life (ASL)		
ELG/ASL Amortization Period	20 years	34 years (2.98%)
ELG/ASL Deferred Until	2022/23	Indefinite

Scenario 1

The financial statements provided below reflect MH16 updated for the same assumptions outlined above for Attachment 28 ("MH16 Scenario 1"), with the depreciation of the associated regulatory deferral account flowing through Net Movement. MH16 and MH16 Scenario 1 commence amortization of the regulatory deferral account midway through 2017/18.

Manitoba Hydro has observations and concerns with respect to MH16 Scenario 1 that are summarized below.

1. **Without the proposed rate increases, Manitoba Hydro's cash flow from operations is insufficient to fund its ongoing business requirements**

The indefinite deferral and extended amortization periods of the depreciation and overhead impacts of IFRS reflected in MH16 Scenario 1 yield a $1 billion growth in regulatory deferral accounts. This growth represents more than a doubling of the regulatory deferral account balances, with MH16 Scenario 1 having $1.8 billion compared to MH16 having $0.8 billion in regulatory deferral accounts by 2035/36. The $1 billion growth in the regulatory deferral account balances result in no substantive change in Manitoba Hydro's financial ratios over the 20-year period despite higher net income and retained earnings levels. The debt to equity ratio target of 25% is still achieved in 2026/27 in both MH16 and MH16 Scenario 1 with immaterial changes to the EBITDA interest coverage and capital coverage ratios.

Notably, an improvement in net income does not necessarily equate to an improvement in cash flow which is key to sustaining and improving the financial strength of Manitoba Hydro. In fact, this scenario results in a net decrease in cash flows to the utility over the forecast as a result of additional capital taxes paid on larger asset balances in the future years of the forecast. As discussed in section 2.2 of Tab 2 of this Application, without the proposed and indicative rate increases, Manitoba Hydro is $1.1 billion cash flow negative on its core operations for the next five years.

MH16 Scenario 1 does not change the need for the proposed and indicative rate increases, which allow a prospective level of income and cash flow that would begin restoring financial strength while also being capable of enduring drought or material negative deviations from forecast (export prices, interest rates) without requiring emergency relief from ratepayers.

2. Substantial growth in regulatory deferral accounts results in intergenerational inequity and poses a risk to rate stability for future ratepayers

MH16 Scenario 1 demonstrates that the indefinite deferral of customer cost recovery and the use of extended amortization periods (i.e. 30 years or more) to recognize the depreciation and overhead impacts of IFRS will result in $1 billion growth in regulatory deferral accounts.

Manitoba Hydro is of the view that a $1.8 billion regulatory deferral account balances reflect inter-generational inequity in that the burden of recovery of today's IFRS impacts is simply being pushed out to future rate payers. As previously indicated in Attachment 28 of Manitoba Hydro's 2016/17 Supplemental Filing, Manitoba Hydro's concerns are similar to those documented in the 2011 report published by the Office of The Auditor General of British Columbia titled, "*BC Hydro: The Effects of Rate-regulated Accounting*". At the time of the report, BC Hydro's regulatory deferral account balances approximated $2.2 billion. The concern of the BC Auditor General with respect to the extremely high regulatory deferral account balances was as follows:

> *p. 13 "While deferral accounts can be helpful in ensuring rate stability in the near term, over the long term significant costs deferred today may be unfairly passed on to future ratepayers who receive little or no benefit. This concept of a potential unequal matching of costs and benefits is known as intergenerational inequity."*

There is also the risk that this approach of indefinite deferral and extended amortization could result in excessive regulatory account balances such that Manitoba Hydro's external auditors will become concerned over the ability of the utility to recover these amounts from ratepayers. Under such circumstances, the auditors may require the write-off of the regulatory deferral account balances to net income as the amounts no longer qualify for recognition as a regulatory deferral.

Scenario 2

Scenario 2 of Attachment 28 from the 2016/17 Supplemental Filing requested the presentation of amortization of these regulatory accounts through Other Comprehensive Income ("OCI") as opposed to net income. As documented in Attachment 28 from the 2016/17 Supplemental Filing and as discussed in Section 10.4.4 of Tab 10 of this Application, amortization of regulatory balances in OCI is not compliant with the regulatory accounting requirements of *IFRS 14 Regulatory Deferral Accounts* unless those accounts specifically relate to balances required to be recognized in OCI as required by other IFRS standards. In understanding the relationship between the authority of the regulator and the authority for the accounting of regulatory impacts, the regulator has the authority to influence the timing of when expenditures and revenues may be recognized in net income for rate setting purposes whereas the accounting standards (IFRS) have the authority over how the regulatory impacts are to be presented in the financial statements.

Given that the amortization of the deferred regulatory accounts in OCI is not compliant with IFRS, Scenario 2 has not been prepared.

ELECTRIC OPERATIONS (MH16)
PROJECTED OPERATING STATEMENT
MH16 Scenario 1 (MIPUG MFR 5)
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
REVENUES											
Domestic Revenue											
at approved rates	1 517	1 569	1 561	1 552	1 551	1 552	1 559	1 567	1 577	1 584	1 593
additional*	-	88	255	397	551	717	766	817	870	923	979
BPIII Reserve Account	(96)	(119)	9	71	71	71	71	24	-	-	-
Extraprovincial	468	454	432	455	578	696	795	818	844	707	714
Other	27	30	31	31	33	33	34	34	35	35	36
	1 915	2 022	2 287	2 507	2 784	3 069	3 225	3 260	3 325	3 250	3 321
EXPENSES											
Operating and Administrative	535	518	501	511	513	524	536	548	559	571	583
Finance Expense	613	574	662	721	774	829	1 049	1 072	1 057	1 033	999
Finance Income	(18)	(16)	(20)	(27)	(27)	(32)	(38)	(17)	(21)	(22)	(17)
Depreciation and Amortization	384	396	471	515	554	597	689	714	725	739	751
Water Rentals and Assessments	131	124	112	113	114	117	127	128	131	131	131
Fuel and Power Purchased	130	135	166	146	162	149	140	138	141	128	129
Capital and Other Taxes	118	132	145	154	161	165	174	174	175	175	176
Other Expenses	60	115	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 962	1 987	2 153	2 623	2 354	2 449	2 755	2 829	2 842	2 833	2 835
Net Income before Net Movement in Reg. Deferral	(47)	35	134	(116)	430	620	469	431	483	416	486
Net Movement in Regulatory Deferral	69	69	111	467	76	69	50	39	37	36	38
Net Income	22	104	245	351	506	689	519	470	520	452	524
Net Income Attributable to:											
Manitoba Hydro	**34**	**112**	**246**	**349**	**501**	**681**	**510**	**459**	**517**	**451**	**521**
Non-controlling Interest	(12)	(9)	(1)	2	5	8	9	11	3	2	3
* Additional Domestic Revenue											
Percent Increase	0.00%	7.90%	7.90%	7.90%	7.90%	7.90%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	7.90%	16.42%	25.62%	35.55%	46.25%	49.18%	52.16%	55.21%	58.31%	61.48%
Financial Ratios											
Equity	15%	15%	14%	15%	16%	18%	19%	21%	22%	24%	26%
EBITDA Interest Coverage	1.50	1.57	1.76	1.88	2.01	2.21	2.15	2.13	2.22	2.20	2.32
Capital Coverage	1.08	1.31	1.49	1.69	2.11	2.60	2.33	2.30	2.17	2.00	2.09

ELECTRIC OPERATIONS (MH16)
PROJECTED OPERATING STATEMENT
MH16 Scenario 1 (MIPUG MFR 5)
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 608	1 623	1 639	1 667	1 698	1 730	1 762	1 796
additional*	1 034	1 093	1 158	1 225	1 304	1 389	1 478	1 571	1 669
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	708	721	733	744	745	743	739	732	654
Other	36	37	38	38	39	40	40	40	41
	3 378	3 458	3 551	3 647	3 756	3 869	3 987	4 106	4 161
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	989	973	938	914	871	835	791	752	712
Finance Income	(26)	(37)	(25)	(16)	(18)	(18)	(22)	(34)	(45)
Depreciation and Amortization	764	775	790	804	822	840	856	871	887
Water Rentals and Assessments	131	132	132	132	133	133	133	134	134
Fuel and Power Purchased	129	131	135	145	151	159	167	178	172
Capital and Other Taxes	176	177	179	180	181	183	184	186	192
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	2	2	2	2	2	2
	2 846	2 850	2 861	2 882	2 878	2 884	2 878	2 871	2 852
Net Income before Net Movement in Reg. Deferral	532	607	691	765	878	985	1 109	1 235	1 309
Net Movement in Regulatory Deferral	38	40	44	45	45	47	45	43	40
Net Income	571	647	735	810	923	1 032	1 154	1 279	1 349
Net Income Attributable to:									
Manitoba Hydro	**567**	**643**	**727**	**801**	**912**	**1 020**	**1 140**	**1 264**	**1 334**
Non-controlling Interest	4	5	7	9	11	12	14	15	15
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	64.71%	68.00%	71.36%	74.79%	78.28%	81.85%	85.49%	89.19%	92.98%
Financial Ratios									
Equity	28%	30%	33%	36%	39%	43%	47%	52%	56%
EBITDA Interest Coverage	2.40	2.53	2.68	2.81	3.06	3.30	3.61	3.98	4.32
Capital Coverage	2.14	2.19	2.35	2.35	2.51	2.63	2.78	2.70	2.75

ELECTRIC OPERATIONS (MH16)
PROJECTED BALANCE SHEET
MH16 Scenario 1 (MIPUG MFR 5)
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
ASSETS											
Plant in Service	13 256	13 881	19 254	19 876	20 938	26 363	30 693	31 222	31 858	32 522	33 133
Accumulated Depreciation	(985)	(1 319)	(1 749)	(2 197)	(2 634)	(3 143)	(3 724)	(4 347)	(4 961)	(5 625)	(6 231)
Net Plant in Service	12 272	12 562	17 505	17 679	18 304	23 219	26 969	26 876	26 897	26 897	26 902
Construction in Progress	6 943	9 308	6 596	7 378	7 870	3 693	224	312	276	272	269
Current and Other Assets	1 721	1 909	2 275	2 451	2 239	1 916	1 726	1 920	2 073	1 803	1 984
Goodwill and Intangible Assets	270	485	725	869	1 271	1 225	1 180	1 135	1 092	1 049	1 007
Total Assets before Regulatory Deferral	21 206	24 264	27 101	28 377	29 684	30 054	30 099	30 243	30 338	30 021	30 162
Regulatory Deferral Balance	459	528	638	1 105	1 181	1 251	1 300	1 339	1 376	1 412	1 450
	21 664	24 792	27 740	29 482	30 865	31 305	31 399	31 582	31 713	31 432	31 612
LIABILITIES AND EQUITY											
Long-Term Debt	15 578	17 920	21 157	21 782	22 554	22 881	22 905	22 474	21 786	20 525	21 167
Current and Other Liabilities	3 415	3 905	3 303	4 067	4 209	3 666	3 249	3 417	3 708	4 226	3 232
Provisions	19	19	19	18	17	16	16	15	14	14	14
Deferred Revenue	444	460	486	515	537	546	556	566	577	588	599
BPIII Reserve Account	196	316	307	236	165	94	24	(0)	(0)	(0)	(0)
Retained Earnings	2 730	2 843	3 088	3 438	3 938	4 619	5 129	5 588	6 104	6 555	7 076
Accumulated Other Comprehensive Income	(761)	(714)	(665)	(616)	(600)	(562)	(522)	(521)	(520)	(520)	(520)
Total Liabilities and Equity before Regulatory Deferral	21 621	24 748	27 696	29 439	30 821	31 261	31 355	31 538	31 670	31 389	31 569
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44	44	44
	21 664	24 792	27 740	29 482	30 865	31 305	31 399	31 582	31 713	31 432	31 612
Net Debt	15 349	18 248	20 527	22 028	22 835	22 968	22 670	22 207	21 665	21 204	20 669
Total Equity	2 778	3 106	3 470	3 873	4 380	5 073	5 271	5 729	6 260	6 724	7 259
Equity Ratio	15%	15%	14%	15%	16%	18.09%	19%	21%	22%	24%	26%

ELECTRIC OPERATIONS (MH16)
PROJECTED BALANCE SHEET
MH16 Scenario 1 (MIPUG MFR 5)
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ASSETS									
Plant in Service	33 741	34 487	35 147	35 978	36 754	37 549	38 293	39 095	40 163
Accumulated Depreciation	(6 924)	(7 621)	(8 329)	(9 059)	(9 806)	(10 595)	(11 384)	(12 186)	(12 993)
Net Plant in Service	26 817	26 866	26 817	26 919	26 948	26 955	26 909	26 909	27 170
Construction in Progress	351	313	348	258	232	224	264	319	115
Current and Other Assets	2 442	3 056	2 166	2 184	2 313	2 550	3 348	4 180	5 217
Goodwill and Intangible Assets	967	928	890	852	814	777	740	703	667
Total Assets before Regulatory Deferral	30 576	31 162	30 221	30 214	30 307	30 505	31 261	32 112	33 169
Regulatory Deferral Balance	1 489	1 529	1 573	1 617	1 663	1 709	1 754	1 798	1 838
	32 065	32 691	31 794	31 831	31 970	32 215	33 016	33 909	35 007
LIABILITIES AND EQUITY									
Long-Term Debt	21 120	17 702	15 049	16 670	16 080	16 264	16 318	15 907	15 791
Current and Other Liabilities	3 154	6 545	7 564	5 170	4 976	4 006	3 602	3 631	3 499
Provisions	14	14	14	14	14	14	14	14	14
Deferred Revenue	610	619	629	639	649	660	671	682	694
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7 643	8 286	9 014	9 814	10 727	11 747	12 887	14 151	15 485
Accumulated Other Comprehensive Income	(520)	(520)	(520)	(520)	(520)	(520)	(520)	(520)	(520)
Total Liabilities and Equity before Regulatory Deferral	32 021	32 647	31 750	31 788	31 926	32 171	32 972	33 866	34 964
Regulatory Deferral Balance	44	44	44	44	44	44	44	44	44
	32 065	32 691	31 794	31 831	31 970	32 215	33 016	33 909	35 007
Net Debt	20 087	19 439	18 692	17 895	16 972	15 941	14 771	13 537	12 231
Total Equity	7 841	8 494	9 227	10 036	10 957	11 985	13 134	14 408	15 752
Equity Ratio	28%	30%	33%	36%	39%	43%	47%	52%	56%

ELECTRIC OPERATIONS (MH16)
PROJECTED CASH FLOW STATEMENT
MH16 Scenario 1 (MIPUG MFR 5)
(In Millions of Dollars)

For the year ended March 31	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
OPERATING ACTIVITIES											
Cash Receipts from Customers	2 007	2 131	2 268	2 425	2 701	2 986	3 141	3 224	3 313	3 237	3 308
Cash Paid to Suppliers and Employees	(876)	(917)	(881)	(880)	(903)	(908)	(923)	(938)	(955)	(953)	(966)
Interest Paid	(569)	(529)	(628)	(695)	(737)	(797)	(1 013)	(1 042)	(1 035)	(1 017)	(974)
Interest Received	7	5	12	21	17	17	9	8	14	14	9
	569	689	770	871	1 077	1 298	1 214	1 252	1 337	1 280	1 377
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 743	3 370	3 590	1 970	1 790	790	360	(10)	(10)	(50)	790
Sinking Fund Withdrawals	146	0	0	182	303	767	173	50	330	131	224
Retirement of Long-Term Debt	(1 030)	(330)	(1 002)	(336)	(1 278)	(1 020)	(449)	(290)	(412)	(715)	(1 178)
Other	10	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 868	3 029	2 578	1 805	804	525	95	(255)	(97)	(639)	(169)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 609)	(3 553)	(3 015)	(2 351)	(1 742)	(1 352)	(880)	(700)	(704)	(732)	(756)
Sinking Fund Payment	(146)	(246)	(210)	(244)	(282)	(334)	(235)	(241)	(246)	(238)	(235)
Other	(68)	(51)	(55)	(44)	(128)	(91)	(84)	(83)	(83)	(80)	(79)
	(2 822)	(3 850)	(3 280)	(2 639)	(2 152)	(1 777)	(1 199)	(1 024)	(1 033)	(1 050)	(1 070)
Net Increase (Decrease) in Cash	(384)	(131)	68	37	(272)	46	110	(27)	207	(409)	138
Cash at Beginning of Year	944	559	428	496	533	262	308	418	391	598	189
Cash at End of Year	559	428	496	533	262	308	418	391	598	189	328

ELECTRIC OPERATIONS (MH16)
PROJECTED CASH FLOW STATEMENT
MH16 Scenario 1 (MIPUG MFR 5)
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 365	3 444	3 538	3 633	3 741	3 855	3 973	4 092	4 147
Cash Paid to Suppliers and Employees	(978)	(993)	(1 010)	(1 033)	(1 054)	(1 075)	(1 098)	(1 123)	(1 137)
Interest Paid	(973)	(966)	(930)	(902)	(857)	(833)	(790)	(763)	(727)
Interest Received	22	40	19	10	12	20	31	51	63
	1 435	1 526	1 617	1 708	1 843	1 967	2 116	2 257	2 346
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(20)	1 780	3 580	1 160	940	350	(90)	(30)
Sinking Fund Withdrawals	150	60	445	361	0	30	0	10	275
Retirement of Long-Term Debt	(150)	(50)	(3 450)	(4 386)	(1 982)	(1 763)	(750)	(340)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(15)	(15)	(1 230)	(450)	(828)	(800)	(404)	(424)	(25)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Sinking Fund Payment	(232)	(233)	(240)	(215)	(201)	(202)	(201)	(204)	(208)
Other	(78)	(72)	(70)	(71)	(70)	(69)	(68)	(66)	(65)
	(1 077)	(1 104)	(1 102)	(1 118)	(1 112)	(1 128)	(1 138)	(1 218)	(1 239)
Net Increase (Decrease) in Cash	343	407	(715)	140	(97)	40	574	615	1 082
Cash at Beginning of Year	328	671	1 078	363	503	406	446	1 020	1 634
Cash at End of Year	671	1 078	363	503	406	446	1 020	1 634	2 716