Consumers Coalition Exhibit CC-4

CONSUMERS COALITION

BOOK OF DOCUMENTS

December 13, 2021

Manitoba Hydro 2021/22 Interim Rate Application

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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

14.0.0 Recommendations

In accordance with the Terms of Reference and based on the evidence presented by Manitoba Hydro, Interveners and the Independent Expert Consultants, the Panel makes the following recommendations.

Manitoba Hydro's Preferred Development Plan

The Panel was requested to assess whether the needs for Manitoba Hydro's Preferred Development Plan are thoroughly justified and sound, its timing is warranted and the factors that Manitoba Hydro relied on to prove its needs are complete, reasonable and accurate. The Terms of Reference also asked the Panel to assess whether the Preferred Development Plan is justified as superior to potential alternatives and is in the best long-term interest of the province of Manitoba. The factors that the Panel considered in reaching its conclusions and recommendations were defined by the Terms of Reference and have been discussed throughout this Report.

The Panel concludes that new generation resources will likely be required no later than 2024. However, Manitoba Hydro has not established that the Preferred Development Plan is the best alternative to meet this need, or has been justified as being in the best long-term interest of the province of Manitoba.

1. ***The Panel recommends that the Government of Manitoba not approve Manitoba Hydro's proposed Preferred Development Plan.***

However, the Panel recommends alternative actions that are better justified in terms of meeting the need for new resources and export opportunities, while addressing the risks to ratepayers and the requirement for a new approach in planning future generation resources. These actions are presented in the recommendations below.

Keeyask Project

The Panel concludes that the Keeyask Project is justified in terms of resource needs for domestic and export requirements. The Panel considered the impending domestic load requirements, and determined that even with the successful implementation of Demand Side Management programs, Manitoba requires new, long-term energy supply based on the hydropower from the Keeyask Project. The Panel was persuaded by the commercial realities of the Keeyask Project, including some $1.2 billion already spent on the Project, as well as the supporting export contracts and the socio-economic benefits from partnership agreements with First Nations.

The Panel considered the question of the in-service date and, in light of the potential impacts of Demand Side Management initiatives, whether to recommend deferral of the start of Keeyask's construction. The Panel notes the need for new capacity as a result of load demands associated with expected new pipeline construction. Agreements also have been signed with the Keeyask Cree Nations that could be adversely affected by delay. As a result, the Panel found no convincing reason to delay the in-service date of 2019 for the Keeyask Project.

2. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the construction of the Keeyask Project to achieve a 2019 in-service date.

750 MW Transmission Interconnection Project

Manitoba Hydro has demonstrated the value of constructing the proposed 750 MW Transmission Interconnection to the United States. Financial and economic analysis indicates that this Transmission Interconnection adds value to Manitoba Hydro's future plans. The Transmission Interconnection is equally justified in terms of its contribution to system reliability, and to address export and import needs during periods of drought or system emergencies.

3. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the 750 MW U.S. Transmission Interconnection Project for a 2020 in-service date.

Conawapa Project

The Panel concludes that Manitoba Hydro has not justified the construction of the Conawapa Project as part of the Preferred Development Plan, or any future plan. In light of the Panel's recommendations on Keeyask, the 750 MW Transmission Interconnection and expected impacts of future Demand Side Management efforts, Conawapa is not needed for either domestic or export needs. It makes no positive contribution to the financial value of the Preferred Development Plan or any alternative resource plans.

4. The Panel recommends that the Government of Manitoba not approve the construction of the Conawapa Project and the North-South Transmission Upgrade Project.

Given the Panel's view that the Conawapa Project has no place in future plans or strategies, there is no need to continue any activity to protect a future in-service date. Nor should existing sunk costs become a future justification for Conawapa.

5. ***The Panel recommends that the Government of Manitoba direct Manitoba Hydro to immediately cease any and all expenditures associated with the design, implementation, and future development of the Conawapa Project.***

Demand Side Management Plans and Programs

During the NFAT Review hearings, the Panel heard that Demand Side Management initiatives were "game changers." The Panel learned that Demand Side Management can have a profound impact on the need for, and timing of, new energy resources. According to its 2014 Supplementary Power Smart Plan, Manitoba Hydro can achieve 1,136 MW and 3,978 GWh of electricity savings by 2028/29. This would amount to more than 80% of the net system capacity addition from the proposed Conawapa Project.

Successful Demand Side Management initiatives are based on ambitious and achievable targets. In recent years and on an annual basis as a percentage of total demand, Manitoba Hydro's DSM savings have declined to approximately 0.4%, well below the 1.5% to 2% levels seen in many other jurisdictions. Demand Side Management savings in the order of 1.5% (including codes and standards) are achievable and economic.

Manitoba Hydro was formerly recognized as a leader in DSM but has since been surpassed by a number of jurisdictions. The Panel is concerned that the full potential for Demand Side Management will not be realized if the responsibility for Demand Side Management remains within Manitoba Hydro. Commitment, independent action and external monitoring of performance are the demonstrated and proven ingredients of successful DSM programs. Interveners encouraged the Panel to take these steps.

6. ***The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.***

7. ***The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.***

8. ***The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.***

9. ***The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.***

10. ***The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro continue to address the barriers to lower income customer participation in its Demand Side Management programs.***

11. ***The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating.***

Rates and Ratepayer Impacts

Manitoba Hydro will have to invest in replacing aging infrastructure and in building Bipole III. This will result in increasing electricity rates over the coming decade. The construction of new generation and associated transmission facilities will add to and prolong these rate increases. Furthermore, construction costs will most likely grow and revenue projections may not be achieved. This gap between rising costs and unrealized revenues will be borne by ratepayers.

Given the length of time projected for these rate increases and their magnitude, especially in the early years, the Panel is concerned about intergenerational fairness and the impact on vulnerable residents and communities. Lower income consumers, particularly those in northern and aboriginal communities where energy choices are limited or non-existent, will especially feel this impact.

The Government of Manitoba will receive significant revenues from incremental capital taxes and water rental fees from the development of the Keeyask Project. It would be reasonable for the Government of Manitoba to use some or all of the incremental revenue it will realize from the Keeyask Project to mitigate adverse rate impacts on vulnerable consumers. Furthermore, Manitoba Hydro should take internal actions to moderate rate increases.

12. ***The Panel recommends that the Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project to be used to mitigate the impact of rate increases on lower income consumers, northern and aboriginal communities.***

13. ***The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases.***

14. ***The Panel recommends that Manitoba Hydro implement cost containment measures to moderate its proposed electricity rate increases.***

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Public Utilities Board | Régie des services publics

Order No. 59/18

FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S 2017/18 AND 2018/19 GENERAL RATE APPLICATION

May 1, 2018

BEFORE: Robert Gabor, Q.C., Chair
Marilyn Kapitany, B.Sc., (Hon), M.Sc., Vice Chair
Hugh Grant, Ph.D., Member
Shawn McCutcheon, Member
Sharon McKay, BGS, Member
Larry Ring, Q.C., Member

levels of poverty. As noted by Manitoba Hydro's President and Chief Executive Officer, there may not be a single solution to this multifaceted bill affordability problem. While government has a role to play in addressing the issue of affordability, so too does Manitoba Hydro and rate design can assist the Utility in fulfilling its role.

The Board concludes that, under its mandate to set rates in the public interest, the Board can and should play a part in addressing bill affordability.

An appropriate starting point for bill affordability in Manitoba is a program targeted at on-reserve ratepayers, specifically through the creation of a First Nations On-Reserve Residential customer class with a differentiated rate to address energy poverty.

The creation of this new customer class is justified by the need to address energy poverty on-reserve, supported by evidence that 96% of First Nations people on-reserve live in poverty and that reserves in Manitoba have the highest rates of child poverty in Canada. In addition, the poor housing stock on reserves in Manitoba and the fact that the vast majority of on-reserve First Nations residential customers (61 out of 63 First Nations communities) have no access to the more economical option of natural gas for heating exacerbate the issue of energy poverty.

The new customer class and related affordability measure of a 0% rate increase are also consistent with the principle of reconciliation. As defined in *The Path to Reconciliation Act*, reconciliation is the ongoing process of establishing and maintaining mutually respectful relationships between Indigenous and non-Indigenous peoples in order to build trust, affirm historical agreements, address healing, and create a more equitable and inclusive society.

Manitoba Hydro is kept whole because the cost of the 0% rate increase for this new customer class has been factored into the level of the average general rate increase granted for the Test Year to all other customer classes. The Board is fully aware that there will be some obvious anomalies created where one household on-reserve will receive a lower rate than a nearby off-reserve household living in similar circumstances. This new customer class is a limited measure designed to reach a targeted group experiencing a high degree of poverty. The anomalies that result from this measure are best addressed by a more wide-reaching government bill affordability program. The Board envisions that, with the introduction of a comprehensive government bill affordability program, the new First Nations On-Reserve Residential customer class and lower rate built into the 2018/19 Test Year may no longer be required.

2.2 Payments to Government

Manitoba Hydro makes payments to the Province of Manitoba for water and land rentals, debt guarantees, and capital and other taxes. Manitoba Hydro also pays grants in lieu of taxes to municipalities. For the fiscal year that ends March 31, 2019, Manitoba Hydro forecasts that it will pay $433 million to governments, with $406 million to be paid to the Province of Manitoba. The evidence in the public hearing demonstrated that, excluding payments made to municipal governments, approximately 17 to 18 cents of each dollar of gross revenue is directed by Manitoba Hydro to the Province of Manitoba.

Manitoba Hydro's major capital expansion places upward pressure on rates, including due to the Utility's increased obligations to the provincial government. With respect to Keeyask, after it is fully in-service Manitoba Hydro will pay an approximate $140 million per year to the Province of Manitoba on account of water rentals, debt guarantee fees, and capital and other taxes. As noted by the Board in its 2014 NFAT Report:

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 Nations communities. This could involve rate relief programs as well as targeted DSM programs.

Previously, the provincial government indicated it would consider this recommendation from the NFAT Report. The Board continues to be of the view that the provincial government should use some of the revenues that would otherwise accrue as a result of Keeyask in order to fund a comprehensive a bill affordability program.

With respect to Bipole III, the project was initially scoped, designed, and engineered by Manitoba Hydro using the most cost effective route. While the majority of Manitobans are both taxpayers and ratepayers, there is an important distinction. Domestic ratepayers are ultimately responsible for the costs of operating Manitoba Hydro's system, including recovering the costs of Manitoba Hydro's major capital projects once the assets are in service. As a result of a policy decision by the provincial government, the routing of Bipole III was changed to a western route at an additional cost of approximately $900 million. This decision created a $900 million burden for ratepayers with no apparent technical benefit for the new route. The Board considers that this was a policy decision of government that should be a cost to taxpayers, not Manitoba Hydro's ratepayers.

The Board therefore recommends that the provincial government suspend payment of the annual Bipole III debt guarantee fee and capital taxes made by Manitoba Hydro to the provincial government starting with the 2019 fiscal year. Manitoba Hydro – and ultimately the ratepayer - should be reimbursed through suspension of such payments until the $900 million burden of a policy decision made by government is satisfied, estimated at this time to be in 13 years.

Finally, the inter-relationship between Manitoba Hydro and the provincial government will be enhanced with provincial carbon pricing. In the transition to a low-carbon economy, the Province of Manitoba does and will benefit from the strength of its clean hydroelectric resources. As the provincial government will receive revenue from the planned carbon tax, the Board further recommends that the provincial government transfer a portion of the carbon tax revenues to Manitoba Hydro to strengthen Manitoba Hydro's financial health, which may allow for lower consumer rate increases.

2.3 Capital Project Review per Order in Council 92/2017

On April 5, 2017, by Order in Council 92/2017, for the GRA anticipated to be filed by Manitoba Hydro in 2017, the Board was assigned the duty of considering capital expenditures made by the Manitoba Hydro-Electric Board as a factor in the Board reaching a decision regarding setting Manitoba Hydro's rates for services in a manner that balances the interests of ratepayers and the financial health of the Utility.

The Board's review of Manitoba Hydro's capital expenditures included the following projects:

- Keeyask, with a focus on the reasonableness of Manitoba Hydro's capital cost estimates filed in support of the Utility's financial forecasts. The timeframe for the review began with the cost estimates presented at the NFAT;
- Bipole III, also focused on the reasonableness of the capital cost estimates beginning with the initial western routing control budget for Bipole III;

The 7.9% per year rate trajectory in Manitoba Hydro's new 10-year financial plan drives rates to high levels (81% above 2017's level by 2027/28), net income to record levels of $650 million per year and more, with Manitoba Hydro's financial targets (interest coverage and capital coverage) being far exceeded. The Manitoba Industrial Power Users Group maintains the analyses demonstrate that there is no overall financial deterioration compared to the NFAT or the previous GRA and there is therefore no need to deviate from the prior rate trajectory.

Representatives of General Service Small and General Service Medium Customer Classes and the Keystone Agricultural Producers adopt the Morrison Park Advisors' expert evidence, as well as the general positions as to rate increases of the Consumers Coalition and Manitoba Industrial Power Users Group.

The City of Winnipeg maintains that Manitoba Hydro's position as to financial metrics is without sufficient justification and is arbitrary. Most importantly, it states that Manitoba Hydro completely fails to take into consideration the interests of ratepayers. As such, the City of Winnipeg argues that the Utility has failed to demonstrate its proposal results in just and reasonable rates as it considered only half of the legal test the Board must apply – that test being the balancing of the interests of ratepayers and the financial health of the utility.

Simply put, the City of Winnipeg submits the Utility has not established that circumstances have so drastically changed that the conclusions of the NFAT Report are no longer are valid. On this point, this Intervener reminds the Board that Manitoba Hydro does not expect to meet all of its financial targets during periods of major capital expansion. Additionally, the uncertainty analysis from the NFAT modelling shows that rate increases of approximately 3.95% are sufficient to maintain the long-term viability of the Utility.

The Business Council of Manitoba recommends the Board deviate from the historical rate path in favour of a short-term rate path increase along the lines proposed by Manitoba Hydro. This Intervener calculates the difference between the 3.95% rate path and the MH16 Update with Interim rate path as being an incremental revenue increase of about $70 million in the next year. Interest rates going higher than forecast by 1.5% would result in $350 million in additional interest costs that would have to be borne by Manitoba Hydro in 2021 if the Utility's debt is $23.3 billion, as is currently forecasted.

The Business Council of Manitoba sees increases in interest rates and Manitoba Hydro being found to be a non-self-supporting entity as virtual certainties. This Intervener submits that, based on the current credit rating reports, the risk of a credit downgrade of Manitoba Hydro or the Province is extremely high. This Intervener concludes that the risk that any of these factors will negatively affect Manitoba Hydro and the Province in the short and long term is very high.

4.3 Board Findings

Having considered the interests of the Utility's ratepayers and the financial health of Manitoba Hydro, the Board finds that a particular equity level target and pace to achieve that target should not determine the rate increases approved in this GRA. Although the Board finds that the rate increase should not be driven by achievement of a particular equity level, the Board's assessment must include consideration of the circumstances of Manitoba Hydro's operations. Because of Manitoba Hydro's use of hydraulic resources to meet the electricity needs of the province, it has historically undertaken large investments such as generating stations and transmission lines that have initial large surpluses of capacity for the needs of Manitobans. These assets have large upfront construction costs but relatively low annual operating costs that extend through a very long expected useful life – which, in some cases, can be as much as one hundred years. With Manitoba Hydro's investments currently underway in Keeyask and Bipole III, the situation today is no different.

An important question from a rate-setting perspective is how these large investments should be funded. On the one hand, if they are to be paid for exclusively by revenues from new rates charged to domestic ratepayers, this would result in a "saw tooth" pattern of rates featuring sharp spikes when new facilities are under construction, and a return to lower rates once the desired equity portion of the project has been funded. On the other hand, if projects are funded through borrowing, rate increases may be "smoothed" over time but the cost of servicing the debt becomes an issue. The concern is to find the right balance between rate increases and the level of debt to fund large capital projects.

In making this determination, the Board is guided by two considerations. The first is: what "reserves" should Manitoba Hydro hold to manage risk and which risks should it take into account? As an example, as per the question posed in the evidence of Morrison Park Advisors, what is the level of retained earnings needed in the event of a five-year drought? The second is to place concerns about the amount of debt and retained earnings in a different perspective by also considering cash flow, using two long-standing financial metrics used by Manitoba Hydro: interest coverage ratio and the capital coverage ratio.

As detailed below, on assessment of these considerations, the Board finds that raising consumer rates by an amount equivalent to four times the rate of inflation is not required to support Manitoba Hydro's current operations. The Board recognizes the sincerity of Manitoba Hydro's concerns about potential future risks materializing. However, as the Board has demonstrated in past decisions – including in years of drought where the Board awarded rates in excess of those sought by the Utility – it will consider all of the not be met during a period of large capital expenditures when newly constructed assets are placed in service. Accordingly, the 75/25 could remain the long-term objective." The Board supports this view. The Board agrees with the evidence that there is a cost associated with equity as equity is provided by ratepayers who could otherwise use those funds. As such, the Board is not prepared to look at the issue of pacing to achieve a particular equity level target at least until the current phase of major capital construction is completed, now projected by Manitoba Hydro to be in 2024.

The current 25% equity level target was established by the Manitoba Hydro-Electric Board in 1995 when the Utility had 8% equity and less than $300 million of Retained Earnings. Except for approximately five years during the last 20 years, immediately prior to the start of Keeyask construction, this target has not been achieved.

The 25% equity level target is "self-imposed" by Manitoba Hydro. While Manitoba Hydro may determine that the 25% target remains relevant, the Board does not accept that consumer rate increases should be granted at the level proposed by Manitoba Hydro so that the Utility can achieve its target within a 10-year time frame. As stated by the Board in the NFAT report:

> *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.*

Financial Reserves

The Board finds that Manitoba Hydro's forecast achievement of $6.56 billion of Retained Earnings by 2027 is too aggressive considering that the two major capital projects contributing most to the doubling of the Utility's assets are still under construction. This increase in Retained Earnings would be funded by ratepayers, with a resulting opportunity cost. In assessing this cost to ratepayers against the benefits to Manitoba Hydro, the Board finds that under the Utility's MH16 Update with Interim rate path, and as illustrated in Manitoba Hydro's sensitivity analysis and as confirmed by Manitoba Hydro in its testimony, Manitoba Hydro's Retained Earnings would continue to increase even during a five-year drought. Even though a five or seven-year drought would result in Manitoba Hydro not accumulating the same Retained Earnings as it otherwise would have, such a drought would also not result in a reduction in the Utility's Retained Earnings. The Board agrees with the evidence of Morrison Park Advisors, that this raises a question: if a primary purpose of having Retained Earnings is to withstand a drought, why does Manitoba Hydro need rates at a level that would allow it to build Retained Earnings during a drought? The Board concludes this supports the determination that a 7.9% rate increase for 2018/19 is not required.

In addition, the Board accepts the evidence of Morrison Park Advisors that Retained Earnings should be used to manage drought risk in combination with regulatory action by the Board. The Board further agrees that interest rate and export price risks over the long term should be addressed with rate increases as and when those risks materialize. Rates should not be set to increase Retained Earnings to manage those longer-term risks. As discussed elsewhere in this Order, the Board is prepared to consider regulatory action when required to address emerging risks facing Manitoba Hydro. In this context, and having considered Manitoba Hydro's new financial plan and the opportunity costs to ratepayers, the Board finds that the 7.9% requested and projected rate plan is not the appropriate balanced plan for meeting the risks and challenges that confront the Utility.

Public Utilities Board — Régie des services publics

However, the Board concludes that there is merit to gaining better understanding of the financial reserves required for Manitoba Hydro under various circumstances. This would include consideration of risk tolerances, what risks should be protected by reserves, and the circumstances which would guide the need for more aggressive rate increases to continue full cost recovery for Manitoba Hydro. The Board is mindful that the financing and depreciation expenses related to these new major capital assets entering service already require additional revenues from rate increases. Consideration of the appropriate level of financial reserves, for example a minimum retained earnings test, is best done through a collaborative approach with stakeholders.

The Board directs Manitoba Hydro to participate in a technical conference hosted by Board Staff or an external consultant appointed by the Board for the consideration of the establishment of a minimum retained earnings or similar test to provide guidance in the setting of consumer rates for use in rule-based regulation. The test or rule is to be based on maintaining appropriate or minimum levels of retained earnings and meeting other financial metrics in the face of potential risks to the Utility. The Board will develop the terms of reference for the technical conference. Parties will be invited to contribute to the scope and terms of reference for this initiative.

Cash Flow from Operations

The Board finds that, in assessing whether Manitoba Hydro is meeting its ongoing financial obligations, the focus should be on the accrual accounting methodology used in the Utility's audited financial statements and the financial forecasts used for rate setting. This methodology was also previously used by Manitoba Hydro for rate setting purposes and continues to be used by Manitoba Hydro for its financial forecasting and reporting. Accrual accounting used by Manitoba Hydro includes capitalizing interest to capital projects until those new assets enter service for ratepayers. Once in service, the

The Consumers Coalition further submits that, while Manitoba Hydro engineers know their system and deliver good reliability results, the Utility has not demonstrated that it does so in a cost effective manner. Manitoba Hydro may not be doing the right project at the right time. The Consumers Coalition states that Manitoba Hydro does not have a consistent definition of risk that can be used across the three business units: Generation, Transmission, and Distribution. The Utility also does not have a means of planning and prioritizing capital spending across the different business units or across the different geographical areas it serves. For example, Manitoba Hydro may be spending on a Transmission project when the greater need and the greater reliability benefit may be realized with a Distribution project.

In addition, the Consumers Coalition argues that Manitoba Hydro has underspent on Business Operations Capital by 18% over the past three years compared to its planned spending, indicating that Manitoba Hydro's estimates for Test Year Business Operations Capital spending cannot be relied upon for rate setting purposes.

The Manitoba Industrial Power Users Group noted the assessment of the Boston Consulting Group that the equity ratio benefits from reduced spending on Business Operations Capital. In what was described by the Boston Consulting Group as a "Realistic 5-year Change", the deferral of low value capital projects totaling $100 million per year for five years shows a sustained benefit to the equity ratio through the year 2035 (i.e. the deferral was not depicted as a temporary change). In the view of the Manitoba Industrial Power Users Group, Manitoba Hydro has opportunities to reduce its Business Operations Capital spending, and has proven in the past that it is capable of reducing expenditures from forecast amounts.

6.3 Board Findings

The Board finds that, while in a period of major capital spending on Keeyask and Bipole III, Manitoba Hydro should find savings in Business Operations Capital.

The Board does not accept the Business Operations Capital spending forecast in Capital Expenditure Forecast CEF16. The Board does not accept that all Test Year investments are condition-driven and reasonably required for the safe and reliable operation of the system. The Board finds that Business Operations Capital spending can be safely decreased by $160 million, based on Manitoba Hydro's evidence that it can defer $160 million of spending in the Test Year. This is consistent with the Board's findings in Order 73/15 that Manitoba Hydro has not adequately evaluated the long-term pacing and prioritization requirements for Business Operations Capital spending. In that Order, the Board did not endorse Manitoba Hydro's long-term Business Operations Capital plan. The Board accepts the evidence that Manitoba Hydro can reduce the level of spending from its forecast and has shown that it has done so in the past, as with the Gillam Town Site Redevelopment project and with the lower spending in the past three years than was originally forecast.

Based on the suggestion of the Boston Consulting Group in its initial report that the spending reductions can be maintained over a longer period, this issue will be revisited at future GRAs. Reducing Business Operations Capital helps offset the expenditures on Keeyask, which are anticipated to mostly be complete by 2023. Reductions in Business Operations Capital result in a reduced need to borrow funds and will enhance Manitoba Hydro's cash flow. Furthermore, the additional reliability obtained from Bipole III and additional generating capacity from Keeyask mean Manitoba Hydro will have added system-level redundancy, reducing the need for non-critical generation investments.

In addition to the positive impact on Manitoba Hydro's cash flow, reducing Business Operations Capital also results in improvement to the debt-to-equity ratio. Manitoba Hydro's analysis also shows that a reduction of capital spending of $100 million annually increases its retained earnings by $414 million after 10 years.

The Board accepts METSCO's evidence that Manitoba Hydro cannot demonstrate the proposed spending is necessary or has been optimized to any extent. Manitoba Hydro acknowledges that it has not evaluated alternative Business Operations Capital spending scenarios or the performance and reliability impacts of different Business Operations Capital spending levels.

The Board recognizes that Order in Council 92/2017 does not give the Board authority to direct Manitoba Hydro to amend its planned Business Operations Capital spending. Rather, the Board has factored into its rate decision the reduction in Business Operations Capital of $160 million. Manitoba Hydro can decide whether to accept the Board's finding and reduce its Test Year Business Operations Capital spending, or to incur additional debt in order to maintain spending at the proposed levels in CEF16.

The reduction in spending on Business Operations Capital in no way diminishes Manitoba Hydro's responsibility and obligation to provide for an ongoing safe and reliable supply of energy to its customers in the most efficient and environmentally sensitive manner. The Board expects that Manitoba Hydro will appropriately assess, plan, and prioritize Business Operations Capital spending in order to meet its obligations in this regard.

The Board finds that Manitoba Hydro has taken initial steps towards developing asset management processes, and is to be commended for doing so in order to better ensure that the financial resources allocated to Business Operations Capital bring maximum

Rate Increase for 2018/19

Manitoba Hydro's request for an April 1, 2018 rate increase of 7.9% is denied. The Board finds that Manitoba Hydro has not met its onus of proving that a 7.9% rate increase is just and reasonable. A 7.9% rate increase is not required for Manitoba Hydro's operations in the Test Year. In addition, the Board does not accept that achieving a 25% equity level in 10 years is an adequate reason in itself to justify a rate increase of 7.9% in 2018/19.

The Board finds that Manitoba Hydro failed to present economic impacts of the 7.9% rate increase or the impact on customers in various sectors – such as residential, commercial, and industrial. In future rate applications, the Utility is to assess the broader impacts of rate increases beyond only the financial health of Manitoba Hydro. The Board is concerned about the impact of electricity rate increases that are four times the rate of inflation in light of impending carbon taxes, both of which will affect individuals and Manitoba businesses, groups, and organizations. Representatives from industry, as well as agricultural representatives and individual ratepayers that presented evidence, stressed the need for stable and predictable rate increases. A summary of the evidence provided by presenters in the GRA proceeding is contained at Appendix C to this Order.

Based on a balancing of the interests of the ratepayers with the financial health of Manitoba Hydro, the Board approves on a final basis an overall rate increase of 3.6% effective June 1, 2018. As discussed below, the Board also approves rate increases that vary by customer class.

The Board finds an overall rate increase of 3.6% to be just and reasonable and in the public interest as it affords Manitoba Hydro sufficient revenues for financial purposes including cash flow and payments of operating expenses, interest expense, and capital expenses. With this rate increase, the Board finds that Manitoba Hydro has sufficient revenue to operate its business, manage its risks, and pay its finance expenses. From the evidence, the Board finds that the overall rate increase awarded in this Order will provide the revenues required to maintain Manitoba Hydro's cash flow and to allow the Utility to manage its debt advantageously for ratepayers. The Board's recommendations on capital expenditures and demand side management will also assist the Utility in this regard.

The Integrated Financial Forecast filed in the proceeding as Manitoba Hydro Exhibit 93 supports the Board's decision on the level of the overall rate increase. This financial scenario included: continued deferral of $20 million in ineligible overheads, amortized at a 30-year rate; Average Service Life depreciation methodology, without amortization of the difference with the Equal Life Group methodology; achievement of a 25% equity level over a longer period of time, specifically by 2035/36; and debt management based on a weighted average term to maturity of 12 years. In many respects, and as a departure from Manitoba Hydro's plan and Integrated Financial Forecast assumptions, Manitoba Hydro Exhibit 93 is therefore reflective of many of the Board's decisions in this Order.

Beginning in the Test Year, the Manitoba Hydro Exhibit 93 Integrated Financial Forecast scenario results in equal annual rate increases of 3.57%. The Board finds that with minor adjustments, this scenario is directionally consistent with the Board's decisions in this Order.

The Board finds that the 3.6% overall rate increase is to be effective June 1, 2018 in order to begin to move Manitoba Hydro back to a regulatory cycle that is consistent with the start of its fiscal year. The Board accepts that there is a benefit to both Manitoba Hydro and ratepayers in moving back to a regular regulatory cycle. If Manitoba Hydro does not adjust its planning to allow for sufficient time for the Board's review of the next GRA, any rate increase granted will not be effective April 1, regardless of the Board's intention to return the Utility to a regular regulatory cycle.

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Public Utilities Board

Régie des services publics

Order No. 69/19

FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S 2019/20 GENERAL RATE APPLICATION

May 28, 2019

BEFORE: Robert Gabor, Q.C., Chair
Marilyn Kapitany, B.Sc., (Hon), M.Sc., Vice-Chair
Hugh Grant, Ph.D., Member
Shawn McCutcheon, Member
Larry Ring, Q.C., Member

The Board notes Manitoba Hydro has historically provided IFFs that included projections of equal annual rate increases premised on the Utility attaining a financial target over a specific timeframe, roughly 20 years. In prior Orders dating back to the time of the 2014 Needs For and Alternatives To Review, the Board relied on IFFs that included projected equal annual rate increases in the range of 3.57% to 3.95%.

As the MHEB is in the process of developing a new financial plan for Manitoba Hydro, those prior rate trajectories based on now out-dated financial targets are of questionable value in the current proceeding. However, those rate trajectories provide directional guidance to the Board in determining the appropriate level of the rate increase for 2019/20 to assist in smoothing consumer rates when major new capital projects enter service. This further supports the 2.5% rate increase approved by the Board.

The Board notes the evidence of the expert witness for the Manitoba Industrial Power Users Group that the Board's rate regulation of Manitoba Hydro has long used long-term financial forecasts as a tool in rate setting. This so-called "modified cost of service" approach allows for consideration of rate stability, measured rate transitions, and the appropriate level of customer-funded reserves. In the absence of a long-term financial forecast, the Board is challenged in its ability to assess the appropriate level of a rate increase in the 2019/20 test year to reduce the likelihood of future rate shock to consumers. While the evidence in this GRA establishes that it is just and reasonable to approve a 2.5% rate increase in 2019/20 for certain rate classes with the full revenues from the rate increase directed to a Major Capital Deferral Account, the Board expects that it will be necessary to assess future rates in the context of a long-term financial forecast given the expected in-service for Keeyask.

The limitations in this proceeding that arose from the Utility not filing an IFF demonstrate the importance of such long-term financial forecast being available as a tool in rate setting. The Board finds that it is not reasonable to consider another GRA absent a full IFF or other long-term financial forecast. The Board directs Manitoba Hydro to file with its next GRA filing an IFF or other long-term financial forecast in a form consistent with an IFF.

4.0 Operation & Administrative Expenses

Operating and administrative ("O&A") expenses are one of Manitoba Hydro's highest expense categories in its revenue requirement, at over half a billion dollars per year. These expenses primarily consist of wages and benefits, materials, contracted services, and overhead costs associated with operating and maintaining Manitoba Hydro's facilities and providing services to customers. O&A expenses do not include capitalized salaries and benefits for employees who work on capital projects, or materials and services related to those capital projects.

In February 2017, Manitoba Hydro began implementing a plan to reduce its total workforce by 15%, or 900 positions, through a combination of a reduction of the executive leadership and senior management teams and a Voluntary Departure Program. As of March 31, 2018, 821 employees were approved to leave under the Voluntary Departure Program resulting in annual employee-related cost savings of $92.6 million. Due to the timing of the Voluntary Departure Program, Manitoba Hydro was not able to file detailed O&A budgets and related detailed schedules as part of the last GRA. Although there were no detailed budgets, IFF16 incorporated forecast O&A expenses of $518 million in 2017/18, $501 million in 2018/19, and $511 million in 2019/20.

In Order 59/18, the Board accepted Manitoba Hydro's evidence that a detailed O&A forecast could not be filed at that time because of the ongoing Voluntary Departure Program. The Board directed Manitoba Hydro to file with its next GRA the details of its O&A expenditures. While the Board acknowledged Manitoba Hydro's efforts to implement cost containment measures, the Board recommended that Manitoba Hydro continue those efforts both in terms of staff reductions and supply chain management after the conclusion of the Voluntary Departure Program transition. The Board noted that in the 2014/15 & 2015/16 GRA, Manitoba Hydro expressed a commitment to reducing the growth of O&A expenses to 1% annually, excluding the impact of accounting changes.

In the current GRA, Manitoba Hydro relies on a high-level preliminary O&A target of $511 million, reflecting an inflationary increase of 2% over the $501 million of O&A expenses included in the 2018/19 Financial Outlook. The starting point for Manitoba Hydro's establishment of the $511 million O&A target for 2019/20 is the ending 2017/18 actual O&A result, which was used by the Utility to in calculating the 2018/19 O&A budget of $501 million. Manitoba Hydro then escalated the 2018/19 budget by 2% to arrive at the $511 million target for 2019/20.

Manitoba Hydro did not provide a detailed O&A budget for 2019/20. The targeted levels of total OM&A expense for 2018/19 and 2019/20 remain unchanged from what was forecast at the last GRA.

Manitoba Hydro's Position

Manitoba Hydro submits that the $511 million target is valid for rate-setting purposes. This target reflects an inflationary increase of 2% over the $501 million of O&A expenses included in the 2018/19 Financial Outlook. However, the $511 million target has been re-validated by Manitoba Hydro based on current staffing levels and current business requirements. Manitoba Hydro states that the $511 million target will not change with the development of a detailed O&A budget and that it is not possible to achieve further O&A reductions. Manitoba Hydro also stated that limiting growth in O&A expenses to 1% is not sustainable, given the significant staffing reductions that have already taken place, negotiated wage settlements, and cost escalation for materials and services.

Responding to the evidence of the expert witness for the Consumers Coalition, Manitoba Hydro submits that the $22 million reduction in O&A expense identified by that witness is not achievable. Manitoba Hydro states that, in order to reduce O&A expense by $22 million, a staffing reduction of 300 employees would be required – in addition to the 821 positions that have already been reduced through the Voluntary Departure Program. Further staffing reductions would significantly increase risks to public and employee safety, system reliability, and the ability of the Utility to provide reasonable levels of customer service. Regardless, Manitoba Hydro says that its levels of Equivalent Full-Time positions are comparable to the levels in 2004/05, despite growth in Manitoba Hydro's operations in the last 15 years. Further, Manitoba Hydro argues that reductions in O&A

expense in 2019/20 will not address the fundamental issue facing Manitoba Hydro's financial health: the significant revenue shortfall following the in-service date of Keeyask and associated transmission projects.

Intervener Positions

The Consumers Coalition, the only Intervener to take a position on this issue, argues that Manitoba Hydro has not provided key supporting evidence for its 2019/20 O&A target, particularly due to the fact that the Utility did not file an updated or detailed O&A forecast or budget for this test year. As such, the Consumers Coalition submits that the Board should not adopt Manitoba Hydro's O&A budget for rate-setting purposes.

Adopting the evidence of its expert witness, the Consumers Coalition takes the position that the $511 million O&A target for 2019/20 should first be reduced for rate-setting purposes to $495.6 million, and second, should further be reduced to $489 million through the use of an escalation number of 1%. The first budget reduction is to normalize both for an $8.1 million non-recurring increase in collection costs from 2017/18 (the starting point for the Utility's O&A target) and a $7.3 million provision for unallocated transitional contingency funds for which there are no planned costs. The second reduction, based on the use of a 1% escalation number, is recommended by this Intervener as a means of sending a signal to Manitoba Hydro to further reduce costs in a period of transition while reducing the trajectory of O&A costs going forward. The Consumers Coalition argues that these reductions are equivalent to a 1.9% rate decrease by 2022/23 for customers – or put another way, a 1.9% rate increase that Manitoba Hydro does not need to collect from ratepayers.

Board Findings

The Board finds that Manitoba Hydro's 2019/20 O&A target is not accepted for rate-setting purposes. First, the target is premised on a high-level target calculation from early 2017 for the 2017/18 year, and includes two prior non-recurring costs that should be normalized in establishing a target for rate-setting purposes.

The Board finds that the 2019/20 O&A target should be reduced by $8.1 million. This is the amount of a one-time increase in collection costs in 2017/18 as a result of an assessment of collectability of arrears. The $8.1 million was used in the calculation of the 2018/19 budget, which was in turn used in establishing the 2019/20 target. The Board does not accept that the 2019/20 test year O&A target should include this $8.1 million for rate-setting purposes, as it is a one-time occurrence.

Similarly, the Board finds that the 2019/20 O&A target should be reduced by a further $7.3 million – the amount included in the 2019/19 O&A budget to support transitional business requirements arising from the Voluntary Departure Program. This amount was unallocated to specific Operating/Corporate groups and was held as a contingency. These expenses were not incurred in 2018/19 and Manitoba Hydro is not planning for these costs in 2019/20. There are also no actual expenditures associated with this unallocated funding. For these reasons, the test year O&A target should also not include this $7.3 million expense for rate-setting purposes.

Removing both of these expenses from the 2019/20 O&A target reduces the target from $511 million to $495.6 million.

Second, the Panel finds that, in developing the 2019/20 O&A target for rate-setting purposes, an escalation of 1% above the 2018/19 Financial Outlook is to be used. The Utility's primary basis for the 2% escalation rate was that it is an inflationary increase. Manitoba Hydro's evidence did not establish that a 2% escalation rate should be used. Moreover, the Board is concerned that the use of a rate of escalation of 2% will erode all of the O&A savings achieved by Manitoba Hydro through the Voluntary Departure

Program and supply chain management within the early years of Keeyask entering service. This offsetting of savings would be inconsistent with the intent of the Voluntary Departure Program and contrary to the need for Manitoba Hydro to find savings in controllable costs during a period of major capital expansion and related rate pressures.

In the absence of evidence demonstrating the appropriateness of a 2% escalation number, the Board finds that a 1% rate of escalation is to be used for rate setting purposes. This is consistent with Manitoba Hydro's prior commitment dating back to 2013 to limit operating cost increases to 1% per year. As the Board stated in Order 59/18, the Board expects Manitoba Hydro continue its efforts to reduce O&A costs, both in terms of staff reductions and supply chain management. The Board reiterates that cost control should be ongoing, and that it should continue in the post-Voluntary Departure Program years.

Reducing the escalation rate to 1% further reduces the O&A target to $489 million, or $22 million less than Manitoba Hydro's $511 million target. This is equivalent to a 1.3% rate decrease for ratepayers in 2019/20 and will have enduring benefits for ratepayers over time.

The Board is concerned about the lack of detailed information provided by Manitoba Hydro in evidence to support the O&A expenditures incorporated into the filing. As noted by the expert witness for the Consumers Coalition, the Voluntary Departure Program was complete approximately one year ago. It is difficult to understand why Manitoba Hydro has not yet been able to develop a detailed O&A budget. Given the materiality of this expense in Manitoba Hydro's revenue requirement, the Board directs Manitoba Hydro to develop and file a detailed O&A budget with the next GRA filing and provide the year over year dollar and percentage increases for the past five fiscal years. That detailed O&A budget is to include the 2019/20 year, as well as similar detail in support of any years for which Manitoba Hydro seeks a rate increase.

4

Needs For and Alternatives To
DSM Evaluation - 2013 Electric Load Forecast
Pro Forma Financial Statements

Development Plan
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES													
General Consumers Revenue at approved rates	1,331	1,396	1,401	1,408	1,404	1,409	1,413	1,426	1,440	1,455	1,470	1,486	1,501
Additional General Consumers Revenue	-	-	55	110	167	226	288	355	426	501	580	664	752
Extraprovincial	357	408	383	373	430	491	522	571	853	964	993	1,005	1,005
Other	14	15	15	15	15	16	16	16	17	17	17	18	18
Total Revenue	1,702	1,819	1,854	1,906	2,017	2,142	2,240	2,368	2,735	2,938	3,060	3,172	3,276
EXPENSES													
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711
Finance Expense	454	462	511	542	611	693	815	839	1,098	1,201	1,199	1,215	1,214
Depreciation and Amortization	408	439	433	463	476	505	543	553	622	662	670	671	675
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266
Capital and Other Taxes	87	95	103	112	121	129	135	139	142	142	143	145	146
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8
Total Expenses	1,673	1,746	1,835	1,944	2,064	2,218	2,404	2,461	2,869	3,044	3,073	3,112	3,146
Non-Controlling Interest	(14)	(24)	(22)	(17)	(15)	(13)	(9)	(8)	(7)	0	2	7	9
Net Income	43	97	41	(21)	(32)	(64)	(155)	(85)	(127)	(107)	(16)	53	122
Additional General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%
Cumulative General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	7.84%	11.87%	16.06%	20.40%	24.90%	29.58%	34.42%	39.45%	44.67%	50.08%
Debt Ratio	76	78	83	85	87	88	89	90	91	92	92	91	91
Interest Coverage Ratio	1.07	1.16	1.06	0.97	0.96	0.94	0.86	0.93	0.89	0.91	0.99	1.04	1.10
Capital Coverage Ratio	1.04	0.97	0.84	0.85	1.11	1.26	0.97	1.39	1.22	1.25	1.30	1.42	1.57

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
REVENUES												
General Consumers Revenue at approved rates	1,517	1,532	1,548	1,566	1,583	1,601	1,618	1,636	1,649	1,668	1,686	1,704
Additional General Consumers Revenue	845	943	1,046	1,156	1,272	1,394	1,522	762	795	887	910	991
Extraprovincial	939	1,000	987	991	996	1,030	1,035	1,020	1,008	998	988	899
Other	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	3,320	3,494	3,599	3,732	3,872	4,045	4,196	3,439	3,473	3,574	3,606	3,617
EXPENSES												
Operating and Administrative	724	738	752	768	780	793	815	832	852	870	887	907
Finance Expense	1,209	1,185	1,168	1,131	1,094	1,107	1,070	1,037	1,035	1,073	1,088	1,100
Depreciation and Amortization	684	689	682	680	682	704	717	700	695	716	718	721
Water Rentals and Assessments	127	128	128	128	129	132	131	131	131	131	132	132
Fuel and Power Purchased	259	273	275	287	295	284	313	325	344	360	350	319
Capital and Other Taxes	148	149	151	154	157	164	165	167	169	171	173	175
Corporate Allocation	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	3,159	3,170	3,165	3,157	3,145	3,191	3,217	3,198	3,231	3,328	3,354	3,361
Non-Controlling Interest	8	12	14	16	19	21	23	25	27	29	30	32
Net Income	152	312	420	559	707	833	956	215	215	217	221	224
Additional General Consumers Revenue Percent Increase	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	-24.47%	1.08%	3.38%	0.50%	2.74%
Cumulative General Consumers Revenue Percent Increase	55.70%	61.52%	67.56%	73.83%	80.34%	87.08%	94.08%	46.59%	48.18%	53.19%	53.95%	58.17%
Debt Ratio	90	89	87	85	82	79	75	74	73	73	72	71
Interest Coverage Ratio	1.12	1.26	1.35	1.47	1.60	1.72	1.87	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.74	2.31	2.20	2.27	2.40	2.51	3.18	1.56	1.36	1.32	1.27	1.22

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REFERENCE:

Tab 2, PUB MFR12

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an updated table revising the last two columns to provide Actual/ Forecast.

RATIONALE FOR QUESTION:

RESPONSE:

Please see the table below.

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.

6

REFERENCE:

Current Application p.1, PUB/MH I 62 (b)

PREAMBLE TO IR (IF ANY):

In the response to PUB/MH 1-62 (b), MH provides a calculation of the net present value of the proposed annualized rate increase to 2036 utilizing its Weighted Average Cost of Capital.

QUESTION:

Please provide the present value of the (i) total proposed annualized rate increase of $59 million and (ii) annualized rate increase proposed for residential customers of $25 million – in perpetuity using an assumed nominal social discount rate of 5%?

RESPONSE:

i) Based on the Supplement to the 2019/20 Electric Rate Application and a June 1, 2019 implementation, the 3.5% increase is now expected to provide approximately $50 million in revenue for the 2019/20 Year.

   Given the uncertainty of Efficiency Manitoba's DSM Savings levels, the present value in perpetuity was calculated using a 0% growth rate and a 1% 18 year average growth rate. The present value of the proposed annualized revenue associated with the proposed rate increase of 3.5% at a 5.00% nominal social discount rate is $1,303 million (0% growth rate) or $1,457 million (1% growth rate).

In Millions of Dollars

	Nominal Social Discount Rate	Discount Factor	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue
2019	5.00%	1.000	0.00%	0.00%	$0	$0
2020	5.00%	1.050	3.50%	2.97%	50	48
2021	5.00%	1.103	0.00%	3.50%	60	54
2022	5.00%	1.158	0.00%	3.50%	59	51
2023	5.00%	1.216	0.00%	3.50%	60	49
2024	5.00%	1.276	0.00%	3.50%	60	47
2025	5.00%	1.340	0.00%	3.50%	61	45
2026	5.00%	1.407	0.00%	3.50%	61	43
2027	5.00%	1.477	0.00%	3.50%	61	42
2028	5.00%	1.551	0.00%	3.50%	62	40
2029	5.00%	1.629	0.00%	3.50%	62	38
2030	5.00%	1.710	0.00%	3.50%	63	37
2031	5.00%	1.796	0.00%	3.50%	63	35
2032	5.00%	1.886	0.00%	3.50%	64	34
2033	5.00%	1.980	0.00%	3.50%	65	33
2034	5.00%	2.079	0.00%	3.50%	66	32
2035	5.00%	2.183	0.00%	3.50%	66	30
2036	5.00%	2.292	0.00%	3.50%	67	29
PV						**$688**

		Additional Domestic Revenue	0% Growth Rate	1% Growth Rate
A		Nominal Social Discount Rate	5.00%	5.00%
B		Growth Rate	0.00%	1.00%
C	= (A-B)/(1+A)	Capitalization Rate	4.76%	3.81%
D	= 1/C	Terminal Value Multiple	21	26
E		Additional Domestic Revenue (in 2036)	$67	$67
F	= D*E	Terminal Value	$1 411	$1 764
G		Discount Factor (in 2036)	2.292	2.292
H	= F/G	Discounted Terminal Value	$616	$770
I		PV Additional Domestic Revenue (to 2036)	$688	$688
J	= H+I	**PV Additional Domestic Revenue in Perpetuity**	**$1 303**	**$1 457**

Note: Numbers may differ due to rounding.

ii) Based on the Supplement to the 2019/20 Electric Rate Application and a June 1, 2019 implementation, the 3.5% increase for residential customers is now expected to provide approximately $21 million in revenue for the 2019/20 Year.

Given the uncertainty of Efficiency Manitoba's DSM Savings levels, the present value of perpetuity was calculated using a 0% growth rate and a 1% 18 year average growth rate. The present value of the proposed annualized revenue associated with the proposed rate increase of 3.5% at a 5.00% nominal social discount rate is $561 million (0% growth rate) or $628 million (1% growth rate).

In Millions of Dollars

	Nominal Social Discount Rate	Discount Factor	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Residential Revenue	Discounted Additional Residential Revenue
2019	5.00%	1.000	0.00%	0.00%	$0	$0
2020	5.00%	1.050	3.50%	2.97%	21	20
2021	5.00%	1.103	0.00%	3.50%	25	23
2022	5.00%	1.158	0.00%	3.50%	25	22
2023	5.00%	1.216	0.00%	3.50%	25	21
2024	5.00%	1.276	0.00%	3.50%	26	20
2025	5.00%	1.340	0.00%	3.50%	26	19
2026	5.00%	1.407	0.00%	3.50%	26	19
2027	5.00%	1.477	0.00%	3.50%	26	18
2028	5.00%	1.551	0.00%	3.50%	26	17
2029	5.00%	1.629	0.00%	3.50%	27	16
2030	5.00%	1.710	0.00%	3.50%	27	16
2031	5.00%	1.796	0.00%	3.50%	27	15
2032	5.00%	1.886	0.00%	3.50%	28	15
2033	5.00%	1.980	0.00%	3.50%	28	14
2034	5.00%	2.079	0.00%	3.50%	28	14
2035	5.00%	2.183	0.00%	3.50%	29	13
2036	5.00%	2.292	0.00%	3.50%	29	13
NPV						**$294**

		Additional Residential Revenue	0% Growth Rate	1% Growth Rate
A		Nominal Social Discount Rate	5.00%	5.00%
B		Growth Rate	0.00%	1.00%
C	= (A-B)/(1+A)	Capitalization Rate	4.76%	3.81%
D	= 1/C	Terminal Value Multiple	21	26
E		Additional Domestic Revenue (in 2036)	$29	$29
F	= D*E	Terminal Value	$612	$765
G		Discount Factor (in 2036)	2.292	2.292
H	= F/G	Discounted Terminal Value	$267	$334
I		PV Additional Domestic Revenue (to 2036)	$294	$294
J	= H+I	**PV Additional Residential Revenue in Perpetuity**	**$561**	**$628**

Note: Numbers may differ due to rounding.

7

Manitoba Hydro

2017/18 & 2018/19 ELECTRIC GENERAL RATE APPLICATION

Follow-Up Questions to Manitoba Hydro Undertaking Nos. 7 & 8 from Counsel for MIPUG (email dated December 21, 2017)

On December 21, 2017, MIPUG requested the following:

1. Please provide the data values, by year, used to generate Undertaking 8.

2. Add a line (scenario) to Undertaking 8 (the 1990 base scenario) that is based on an IFF as follows (please provide the underlying IFF 6 page financial forecast scenario as well):
   a) IFF16 Update with Interim assumptions, except where noted.
   b) 12 year WATM
   c) Overhead accruals at $20M continue throughout, amortized at 30 year rate (consistent with PUB/MH-I-1(e))
   d) Depreciation at ASL throughout, no amortization of difference with ELG.
   e) Rate increases as necessary consistent with the approach in Coalition-MH-II-19 (i.e., equal annual increases to target 75:25 by 2035/36)
   f) Make sure the graph goes out to 2035/36.
   g) Please also provide the summary data for this scenario as per Undertaking #9 page 2 (i.e., max net debt, etc.)

Response:

Notwithstanding the concerns outlined below, Manitoba Hydro is providing the data values included in Undertaking No. 8 and the projected financial statements, including data values, reflecting the December 21, 2017 MIPUG Scenario.

As noted in the responses to PUB/MH II-21 and PUB/MH II-28, Manitoba Hydro's financial plan reflects a goal to return to its target 25% equity to capitalization ratio in 10 years and believes limited value should be ascribed to forecasts a decade or more in the future. The potential for volatility in key assumptions, many of which are beyond Manitoba Hydro's ability to control, reduces the second half of a 20 year forecast to little more than a hypothetical modeling exercise.

Manitoba Hydro maintains all the same concerns outlined in PUB/MHI-1d) and e) related to items c) and d) of MIPUG's request. Furthermore, the 12 Year WATM in Manitoba Hydro's debt management strategy is justifiable only if there is a reasonable expectation of sufficient cash flow to retire the repositioned debt. The sufficient cash flow stems from the path of higher rate increases in MH16 Update with Interim and not from the rate path included in the scenario requested by MIPUG and presented below.

Manitoba Hydro

The table below outlines the accounting treatment in MH16 Update with Interim, and the assumptions in part c) and d), of the MIPUG scenario.

	MH16 Update with Interim	**MIPUG Scenario Dec 21/17**
Ineligible Overhead		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferral Until	2022/23	Indefinite
Equal Life Group (ELG)/Average Service Life (ASL)		
ELG/ASL Amortization Period	20 years	None
ELG/ASL Deferred Until	2022/23	Indefinite

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MIPUG Scenario December 21, 2017
(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	110	168	228	292	357	425	498	577	660
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	2 178	2 251	2 443	2 642	2 791	2 816	2 891	2 845	2 949
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	831	907	1 159	1 205	1 213	1 211	1 226
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(13)	(12)	(13)	(14)
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	166	174	175	176	177	177
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	2 660	2 406	2 533	2 869	2 965	3 006	3 022	3 069
Net Income before Net Movement in Reg. Deferral	(46)	13	27	(409)	38	109	(78)	(149)	(115)	(177)	(120)
Net Movement in Regulatory Deferral	66	72	115	473	82	78	59	50	50	51	55
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	142	64	120	187	(19)	(99)	(66)	(126)	(65)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	94	143	61	115	178	(29)	(111)	(69)	(128)	(68)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**94**	**143**	**61**	**115**	**178**	**(29)**	**(111)**	**(69)**	**(128)**	**(68)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	142	64	120	187	(19)	(99)	(66)	(126)	(65)
* Additional Domestic Revenue											
Percent Increase		3.36%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
Cumulative Percent Increase		3.36%	7.05%	10.87%	14.82%	18.92%	23.16%	27.56%	32.11%	36.82%	41.70%
Financial Ratios											
Equity	16%	15%	14%	14%	13%	14%	13%	13%	12%	12%	12%
EBITDA Interest Coverage	1.51	1.54	1.64	1.58	1.62	1.69	1.58	1.52	1.57	1.53	1.58
Capital Coverage	1.53	1.40	1.35	1.18	1.41	1.64	1.33	1.27	1.24	1.12	1.20

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MIPUG Scenario December 21, 2017
(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*	747	839	936	1 038	1 152	1 273	1 401	1 538	1 682
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 045	3 167	3 301	3 433	3 569	3 714	3 866	4 029	4 111
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 239	1 242	1 234	1 255	1 242	1 240	1 228	1 195	1 161
Finance Income	(16)	(21)	(19)	(15)	(16)	(17)	(22)	(23)	(25)
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	179	180	181	183	184	186	188	189	196
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 111	3 142	3 170	3 231	3 232	3 265	3 286	3 296	3 288
Net Income before Net Movement in Reg. Deferral	(66)	25	131	202	337	449	580	733	823
Net Movement in Regulatory Deferral	57	61	67	69	72	75	76	76	75
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	(9)	86	197	271	409	525	655	809	899
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	(13)	81	190	261	398	512	641	793	883
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**(13)**	**81**	**190**	**261**	**398**	**512**	**641**	**793**	**883**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	(9)	86	197	271	409	525	655	809	899
* Additional Domestic Revenue									
Percent Increase	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
Cumulative Percent Increase	46.76%	52.00%	57.42%	63.04%	68.85%	74.88%	81.12%	87.58%	94.27%
Financial Ratios									
Equity	12%	12%	13%	14%	15%	17%	19%	22%	25%
EBITDA Interest Coverage	1.63	1.72	1.82	1.87	2.01	2.11	2.25	2.42	2.56
Capital Coverage	1.29	1.39	1.57	1.61	1.81	1.95	2.12	2.12	2.21

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MIPUG Scenario December 21, 2017
(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	2 199	2 477	2 505	1 928	1 682	1 681	1 628	1 770	1 744
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	27 057	28 431	29 997	30 109	30 103	30 051	29 940	30 035	29 969
Regulatory Deferral Balance	462	534	649	1 121	1 204	1 281	1 340	1 390	1 440	1 491	1 546
	21 733	24 839	27 706	29 552	31 200	31 390	31 443	31 442	31 380	31 526	31 515
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 650	24 862	24 735	24 447	24 186	25 228
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 359	4 147	3 027	3 184	3 468	3 993	2 998
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	2 986	3 047	3 162	3 340	3 311	3 200	3 132	3 003	2 935
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(437)	(339)	(338)	(337)	(337)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 657	29 504	31 152	31 341	31 395	31 393	31 331	31 477	31 466
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 706	29 552	31 200	31 390	31 443	31 442	31 380	31 526	31 515
Net Debt	15 427	18 473	20 813	22 628	23 759	24 424	24 666	24 702	24 765	24 891	24 963
Total Equity	2 856	3 163	3 443	3 558	3 698	3 881	3 549	3 532	3 478	3 363	3 309
Equity Ratio	16%	15%	14%	14%	13%	14%	13%	13%	12%	12%	12%

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MIPUG Scenario December 21, 2017
(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	2 012	2 450	2 194	2 054	2 443	2 521	3 066	3 434	4 183
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 192	30 601	30 294	30 127	30 480	30 519	31 020	31 407	32 175
Regulatory Deferral Balance	1 603	1 664	1 731	1 800	1 871	1 947	2 022	2 098	2 174
	31 795	32 265	32 025	31 927	32 351	32 465	33 043	33 505	34 349
LIABILITIES AND EQUITY									
Long-Term Debt	25 560	23 583	21 090	22 750	22 713	23 363	23 080	23 459	23 543
Current and Other Liabilities	2 949	5 307	7 361	5 332	5 386	4 329	4 539	3 819	3 685
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	2 922	3 002	3 192	3 453	3 851	4 363	5 004	5 798	6 680
Accumulated Other Comprehensive Income	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)
Total Liabilities and Equity before Regulatory Deferral	31 747	32 216	31 976	31 878	32 302	32 417	32 994	33 456	34 300
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 795	32 265	32 025	31 927	32 351	32 465	33 043	33 505	34 349
Net Debt	24 971	24 899	24 713	24 476	24 091	23 592	22 950	22 221	21 403
Total Equity	3 310	3 396	3 594	3 863	4 269	4 789	5 439	6 242	7 134
Equity Ratio	12%	12%	13%	14%	15%	17%	19%	22%	25%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

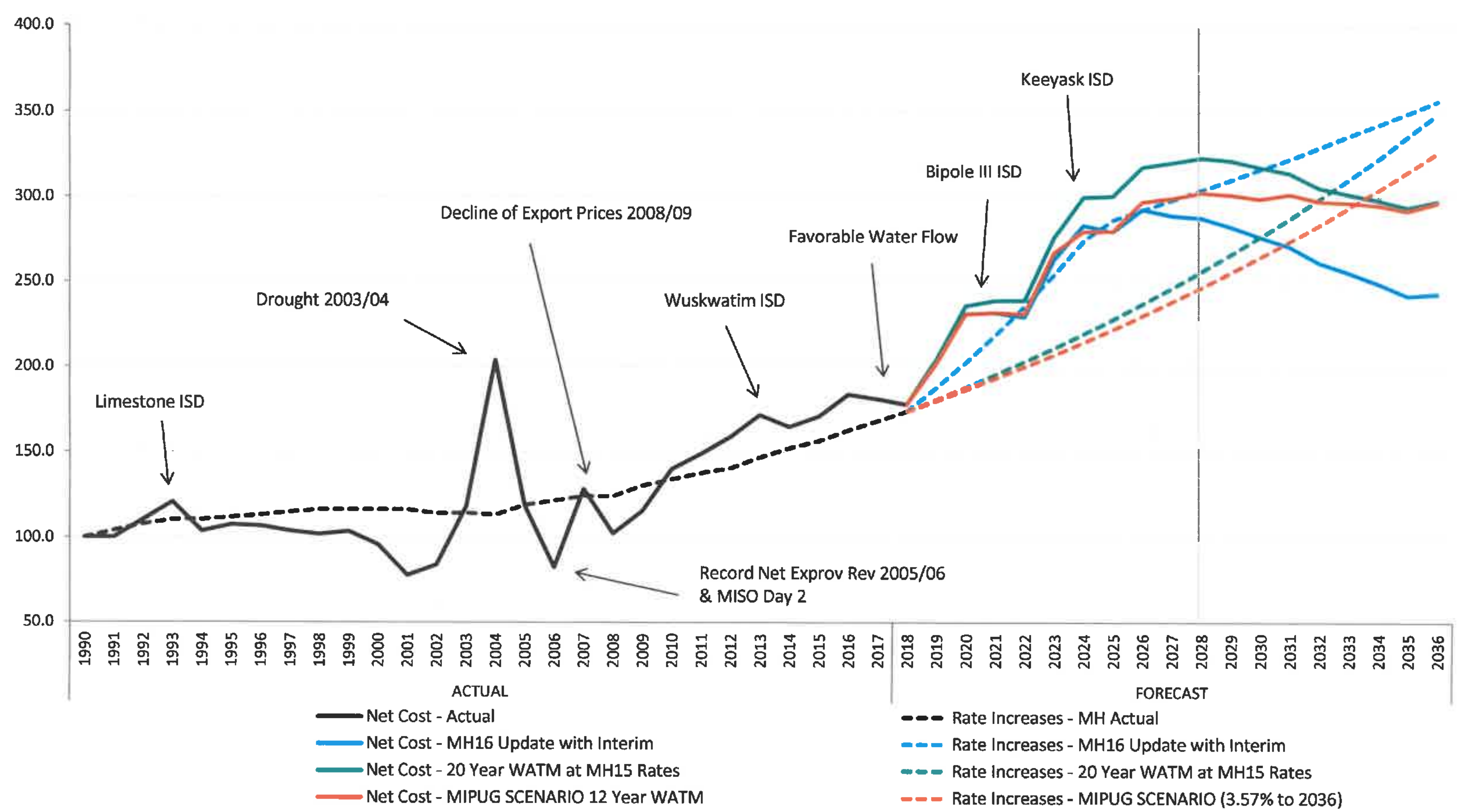
For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 164	2 160	2 352	2 550	2 699	2 777	2 878	2 833	2 936
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(916)	(934)	(934)	(948)
Interest Paid	(553)	(531)	(635)	(704)	(774)	(857)	(1 106)	(1 176)	(1 187)	(1 188)	(1 202)
Interest Received	17	5	11	22	26	19	6	4	6	5	7
	810	734	697	608	718	817	695	690	763	715	792
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 390	1 560	390	390	950	1 190
Sinking Fund Withdrawals	146	0	0	120	318	813	182	54	350	155	253
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(248)	(261)	(270)	(266)	(273)
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	473	364	(111)	53	119	(13)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(720)	(724)	(752)	(776)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 748)	(3 059)	(2 437)	(1 850)	(1 477)	(997)	(816)	(820)	(834)	(858)
Net Increase (Decrease) in Cash	(309)	(146)	4	31	(23)	(187)	62	(237)	(3)	(0)	(78)
Cash at Beginning of Year	943	634	488	492	523	500	313	375	138	135	134
Cash at End of Year	634	488	492	523	500	313	375	138	135	134	56

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MIPUG Scenario December 21, 2017
(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	3 032	3 154	3 287	3 419	3 555	3 700	3 851	4 014	4 097
Cash Paid to Suppliers and Employees	(963)	(979)	(996)	(1 019)	(1 015)	(1 028)	(1 049)	(1 073)	(1 083)
Interest Paid	(1 216)	(1 232)	(1 239)	(1 246)	(1 226)	(1 237)	(1 224)	(1 210)	(1 175)
Interest Received	14	28	27	15	12	23	30	41	41
	867	972	1 079	1 169	1 326	1 458	1 609	1 773	1 880
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	390	1 970	3 990	2 350	1 940	1 160	1 100	570
Sinking Fund Withdrawals	150	60	510	540	0	230	51	10	463
Sinking Fund Payment	(274)	(282)	(291)	(278)	(266)	(276)	(274)	(282)	(289)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 284)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	111	103	(256)	(149)	(294)	(503)	(351)	(663)	74
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(787)	(818)	(813)	(852)	(860)	(877)	(890)	(968)	(986)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(867)	(893)	(884)	(925)	(933)	(948)	(960)	(1 036)	(1 053)
Net Increase (Decrease) in Cash	111	182	(62)	96	99	7	298	75	901
Cash at Beginning of Year	56	167	348	287	383	482	489	787	862
Cash at End of Year	167	348	287	383	482	489	787	862	1 763

MH16 Update with Interim Rate Increases and Net Cost/ Domestic Load



Manitoba Hydro

MH16 Update with Interim														
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
							Millions of Dollars							
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	1990		100	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34		100
	1991	4.00%	104	650	50	67	4	-	-	529	15 447	34	0.1%	100
	1992	3.50%	108	735	54	97	3	-	-	582	15 397	38	10.2%	110
	1993	2.70%	111	843	53	143	3	-	-	644	15 577	41	9.5%	121
	1994	0.00%	111	851	53	232	3	-	-	564	15 870	36	-14.1%	104
	1995	1.20%	112	885	54	253	4	-	-	574	15 600	37	3.6%	107
	1996	1.20%	113	915	56	245	4	-	-	609	16 654	37	-0.7%	107
	1997	1.50%	115	922	50	268	5	-	-	599	16 851	36	-2.8%	104
	1998	1.30%	116	931	46	297	5	-	-	582	16 681	35	-1.8%	102
	1999	0.00%	116	982	48	326	7	-	-	600	16 929	35	1.6%	104
	2000	0.00%	116	976	42	376	11	-	-	547	16 696	33	-7.51%	96
	2001	0.00%	116	1 002	46	480	7	-	-	469	17 590	27	-18.7%	78
	2002	-1.92%	114	1 158	47	588	11	-	-	512	17 805	29	7.9%	84
	2003	0.00%	114	1 277	20	463	15	-	-	779	19 246	40	40.7%	118
	2004	-0.72%	113	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	204
	2005	5.00%	119	1 370	-	554	15	-	-	801	19 735	41	-41.9%	119
	2006	2.25%	122	1 408	-	827	18	-	-	563	19 935	28	-30.4%	83
	2007	2.25%	124	1 511	-	592	16	-	-	902	20 510	44	55.7%	128
	2008	0.00%	124	1 370	-	625	8	-	-	738	21 061	35	-20.4%	102
	2009	5.00%	131	1 478	-	623	16	-	-	839	21 210	40	12.9%	116
	2010	2.84%	134	1 418	-	427	6	-	-	985	20 486	48	21.6%	140
	2011	2.80%	138	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	149
	2012	2.00%	141	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	159
	2013	4.40%	147	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	172
	2014	3.50%	152	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	165
	2015	2.75%	156	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	171
	2016	3.95%	163	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	184
	2017	3.36%	168	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	181
Forecast	2018	3.36%	174	1 995	-	514	30	8	72	1 371	22 510	61	-1.8%	178
	2019	7.90%	187	2 150	-	469	31	1	114	1 535	22 224	69	13.4%	202
	2020	7.90%	202	2 655	-	420	31	(2)	464	1 741	21 977	79	14.7%	231
	2021	7.90%	218	2 392	-	567	33	(5)	71	1 726	21 750	79	0.2%	232
	2022	7.90%	235	2 507	-	693	33	(9)	64	1 725	21 971	79	-1.1%	229
	2023	7.90%	254	2 822	-	779	34	(10)	43	1 977	21 940	90	14.8%	263
	2024	7.90%	274	2 893	-	788	34	(11)	(48)	2 130	21 947	97	7.7%	283
	2025	4.54%	287	2 904	-	805	35	(3)	(50)	2 117	22 103	96	-1.3%	280
	2026	2.00%	292	2 887	-	667	35	(2)	(49)	2 236	22 303	100	4.6%	293
	2027	2.00%	298	2 889	-	671	36	(3)	(45)	2 231	22 531	99	-1.2%	289
	2028	2.00%	304	2 894	-	662	36	(4)	(44)	2 243	22 758	99	-0.5%	288
	2029	2.00%	310	2 892	-	677	37	(5)	(40)	2 223	22 976	97	-1.8%	283
	2030	2.00%	316	2 888	-	697	38	(8)	(35)	2 196	23 204	95	-2.2%	276
	2031	2.00%	323	2 878	-	709	38	(10)	(33)	2 173	23 443	93	-2.1%	271
	2032	2.00%	329	2 833	-	705	39	(11)	(31)	2 130	23 819	89	-3.5%	261
	2033	2.00%	336	2 818	-	701	40	(13)	(28)	2 118	24 216	87	-2.2%	255
	2034	2.00%	342	2 792	-	696	40	(14)	(28)	2 099	24 614	85	-2.5%	249
	2035	2.00%	349	2 762	-	694	40	(15)	(28)	2 071	25 024	83	-2.9%	242
	2036	2.00%	356	2 714	-	602	41	(16)	(30)	2 117	25 442	83	0.5%	243

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

Manitoba Hydro

MH16 Update with Interim with 20 Year WATM and MH15 Rates														
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
							Millions of Dollars							
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	1990		100	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34		100
	1991	4.00%	104	650	50	67	4	-	-	529	15 447	34	0.1%	100
	1992	3.50%	108	735	54	97	3	-	-	582	15 397	38	10.2%	110
	1993	2.70%	111	843	53	143	3	-	-	644	15 577	41	9.5%	121
	1994	0.00%	111	851	53	232	3	-	-	564	15 870	36	-14.1%	104
	1995	1.20%	112	885	54	253	4	-	-	574	15 600	37	3.6%	107
	1996	1.20%	113	915	56	245	4	-	-	609	16 654	37	-0.7%	107
	1997	1.50%	115	922	50	268	5	-	-	599	16 851	36	-2.8%	104
	1998	1.30%	116	931	46	297	5	-	-	582	16 681	35	-1.8%	102
	1999	0.00%	116	982	48	326	7	-	-	600	16 929	35	1.6%	104
	2000	0.00%	116	976	42	376	11	-	-	547	16 696	33	-7.51%	96
	2001	0.00%	116	1 002	46	480	7	-	-	469	17 590	27	-18.7%	78
	2002	-1.92%	114	1 158	47	588	11	-	-	512	17 805	29	7.9%	84
	2003	0.00%	114	1 277	20	463	15	-	-	779	19 246	40	40.7%	118
	2004	-0.72%	113	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	204
	2005	5.00%	119	1 370	-	554	15	-	-	801	19 735	41	-41.9%	119
	2006	2.25%	122	1 408	-	827	18	-	-	563	19 935	28	-30.4%	83
	2007	2.25%	124	1 511	-	592	16	-	-	902	20 510	44	55.7%	128
	2008	0.00%	124	1 370	-	625	8	-	-	738	21 061	35	-20.4%	102
	2009	5.00%	131	1 478	-	623	16	-	-	839	21 210	40	12.9%	116
	2010	2.84%	134	1 418	-	427	6	-	-	985	20 486	48	21.6%	140
	2011	2.80%	138	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	149
	2012	2.00%	141	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	159
	2013	4.40%	147	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	172
	2014	3.50%	152	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	165
	2015	2.75%	156	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	171
	2016	3.95%	163	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	184
	2017	3.36%	168	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	181
Forecast	2018	3.36%	174	1 998	-	514	30	8	72	1 374	22 510	61	-1.8%	178
	2019	3.95%	181	2 171	-	469	31	1	114	1 556	22 224	70	14.7%	204
	2020	3.95%	188	2 692	-	420	31	(2)	464	1 778	21 977	81	15.6%	236
	2021	3.95%	195	2 449	-	567	33	(5)	71	1 783	21 750	82	1.3%	239
	2022	3.95%	203	2 584	-	693	33	(9)	64	1 802	21 971	82	0.0%	239
	2023	3.95%	211	2 925	-	779	34	(10)	43	2 080	21 940	95	15.6%	276
	2024	3.95%	219	3 022	-	788	34	(11)	(48)	2 259	21 947	103	8.6%	300
	2025	3.95%	228	3 067	-	805	35	(3)	(50)	2 280	22 103	103	0.2%	301
	2026	3.95%	237	3 085	-	667	35	(2)	(49)	2 433	22 303	109	5.8%	318
	2027	3.95%	246	3 136	-	671	36	(3)	(45)	2 478	22 531	110	0.8%	320
	2028	3.95%	256	3 176	-	662	36	(4)	(44)	2 525	22 758	111	0.9%	323
	2029	3.95%	266	3 206	-	677	37	(6)	(40)	2 537	22 976	110	-0.5%	322
	2030	3.95%	277	3 223	-	697	38	(8)	(35)	2 531	23 204	109	-1.2%	318
	2031	3.95%	287	3 232	-	709	38	(10)	(33)	2 527	23 443	108	-1.1%	314
	2032	3.95%	299	3 199	-	705	39	(11)	(31)	2 497	23 819	105	-2.8%	305
	2033	3.95%	311	3 207	-	701	40	(13)	(28)	2 507	24 216	104	-1.2%	302
	2034	3.95%	323	3 213	-	696	40	(14)	(28)	2 519	24 614	102	-1.1%	298
	2035	3.95%	336	3 214	-	694	40	(16)	(28)	2 524	25 024	101	-1.4%	294
	2036	3.95%	349	3 197	-	602	41	(16)	(30)	2 600	25 442	102	1.3%	298

* CGAAP 2000-2014, IFRS 2015-2027

** Includes Water Rentals & Assessments and Fuel and Power Purchased

***2017 includes $20 million non-recurring gain

Manitoba Hydro

	MIPUG DECEMBER 21, 2017 SCENARIO													
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
							Millions of Dollars							
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	1990	0	100	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34	0.0%	100
	1991	4.00%	104	650	50	67	4	-	-	529	15 447	34	0.1%	100
	1992	3.50%	108	735	54	97	3	-	-	582	15 397	38	10.2%	110
	1993	2.70%	111	843	53	143	3	-	-	644	15 577	41	9.5%	121
	1994	0.00%	111	851	53	232	3	-	-	564	15 870	36	-14.1%	104
	1995	1.20%	112	885	54	253	4	-	-	574	15 600	37	3.6%	107
	1996	1.20%	113	915	56	245	4	-	-	609	16 654	37	-0.7%	107
	1997	1.50%	115	922	50	268	5	-	-	599	16 851	36	-2.8%	104
	1998	1.30%	116	931	46	297	5	-	-	582	16 681	35	-1.8%	102
	1999	0.00%	116	982	48	326	7	-	-	600	16 929	35	1.6%	104
	2000	0.00%	116	976	42	376	11	-	-	547	16 696	33	-7.51%	96
	2001	0.00%	116	1 002	46	480	7	-	-	469	17 590	27	-18.7%	78
	2002	-1.92%	114	1 158	47	588	11	-	-	512	17 805	29	7.9%	84
	2003	0.00%	114	1 277	20	463	15	-	-	779	19 246	40	40.7%	118
	2004	-0.72%	113	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	204
	2005	5.00%	119	1 370	-	554	15	-	-	801	19 735	41	-41.9%	119
	2006	2.25%	122	1 408	-	827	18	-	-	563	19 935	28	-30.4%	83
	2007	2.25%	124	1 511	-	592	16	-	-	902	20 510	44	55.7%	128
	2008	0.00%	124	1 370	-	625	8	-	-	738	21 061	35	-20.4%	102
	2009	5.00%	131	1 478	-	623	16	-	-	839	21 210	40	12.9%	116
	2010	2.84%	134	1 418	-	427	6	-	-	985	20 486	48	21.6%	140
	2011	2.80%	138	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	149
	2012	2.00%	141	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	159
	2013	4.40%	147	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	172
	2014	3.50%	152	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	165
	2015	2.75%	156	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	171
	2016	3.95%	163	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	184
	2017	3.36%	168	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	181
Forecast	2018	3.36%	174	1 995	-	514	30	8	72	1 370	22 510	61	-1.8%	178
	2019	3.57%	180	2 150	-	469	31	1	115	1 534	22 224	69	13.4%	202
	2020	3.57%	186	2 660	-	420	31	(2)	473	1 738	21 977	79	14.5%	231
	2021	3.57%	193	2 406	-	567	33	(5)	82	1 729	21 750	79	0.5%	232
	2022	3.57%	200	2 533	-	693	33	(9)	78	1 738	21 971	79	-0.5%	231
	2023	3.57%	207	2 869	-	779	34	(10)	59	2 007	21 940	91	15.7%	267
	2024	3.57%	214	2 965	-	788	34	(11)	50	2 104	21 947	96	4.8%	280
	2025	3.57%	222	3 006	-	805	35	(3)	50	2 120	22 103	96	0.0%	280
	2026	3.57%	230	3 022	-	667	35	(2)	51	2 271	22 303	102	6.2%	297
	2027	3.57%	238	3 069	-	671	36	(3)	55	2 311	22 531	103	0.7%	299
	2028	3.57%	247	3 111	-	662	36	(4)	57	2 359	22 758	104	1.1%	303
	2029	3.57%	255	3 142	-	677	37	(5)	61	2 373	22 976	103	-0.4%	302
	2030	3.57%	265	3 170	-	697	38	(8)	67	2 376	23 204	102	-0.8%	299
	2031	3.57%	274	3 231	-	709	38	(10)	69	2 424	23 443	103	0.9%	302
	2032	3.57%	284	3 232	-	705	39	(11)	72	2 427	23 819	102	-1.4%	298
	2033	3.57%	294	3 265	-	701	40	(13)	75	2 462	24 216	102	-0.2%	297
	2034	3.57%	304	3 286	-	696	40	(14)	76	2 489	24 614	101	-0.5%	295
	2035	3.57%	315	3 296	-	694	40	(15)	76	2 501	25 024	100	-1.2%	292
	2036	3.57%	327	3 288	-	602	41	(16)	75	2 585	25 442	102	1.7%	297

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

Manitoba Hydro

To note, in Appendix 1.6 in Manitoba Hydro's Rebuttal Evidence, 3.95% rate increases to 2035/36 results in a 27% equity ratio in that year. Targeting a 25% equity ratio in 2035/36 would yield even annual rate increases of 3.88%. The table below breaks down the impacts of MIPUG's accounting and debt terming assumptions to arrive at 3.57%.

Assumption	Scenario	Even Annual Rate Impact from 2018/19 - 2035/36	Even Annual Rate Increase from 2018/19 - 2035/36
Targeting 25% Equity in 2035/36	MH16 Update with Interim with 20 Year Debt		3.88%
MIPUG's Accounting Changes	MH16 Update with Interim with 20 Year Debt and MIPUG Scenario Ineligible Overhead and ELG/ASL Assumptions	- (0.16%)	3.72%
Debt Terming	MH16 Update with Interim with 12 Year Debt and MIPUG Scenario Ineligible Overhead and ELG/ASL Assumptions	- (0.15%)	3.57%

As requested, the summary data for the December 21, 2017 MIPUG Scenario has been added to the table shown on page 2 of Undertaking #9. The updated table is provided below.

	Long Term Rate Increase	25% Equity Ratio	Maximum Long-Term Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34	Maximum Net Debt
NFAT Plan 5 - High Keeyask Level 2 DSM	3.95% in 2014/15; 3.99% 2015/16 to 2031/32	2031/32	$22.490 B in 2023/24	8% in 2021/22 - 2023/24	Total of $638 M in 8 years during 2015/16 - 2022/23	$6.659 B	$21.606 B in 2022/23
MH14	3.95% 2015/16 to 2030/31	2033/34	$24.476 B in 2028/29	10% in 2022/23 - 2026/27	Total of $977 M in 8 years during 2018/19 - 2025/26	$5.557 B	$23.227 B in 2024/25
MH15	3.95% 2016/17 to 2028/29	2031/32	$23.495 B in 2026/27	12% in 2021/22 - 2023/24	Total of $58 M in 3 years during 2018/19 - 2022/23	$7.402 B	$22.589 B in 2021/22
Coalition/MH II-19 (Based on MH16 Update with Interim)	3.36% in 2017/18; 4.14% 2018/19 to 2033/34	2033/34	$24.972 B in 2027/28	12% in 2025/26 - 2026/27	Total of $347 M in 4 years during 2023/24 - 2026/27	$6.385 B	$24.506 B in 2022/23
Coalition/MH II-19 20 Year WATM (Based on MH16 Update with Interim)	3.36% in 2017/18; 4.34% 2018/19 to 2033/34	2033/34	$25.315 B in 2028/29	11% in 2025/26 - 2026/27	Total of $507 M in 5 years during 2022/23 - 2026/27	$6.377 B	$24.692 B in 2025/26
MIPUG Scenario December 21, 2017	3.36% in 2017/18; 3.57% 2018/19 to 2035/36	2035/36	$25.560 B in 2027/28	12% in 2024/25 - 2028/29	Total of $418 M in 6 years during 2022/23 - 2026/27	$5.004 B	$24.971 B in 2027/28

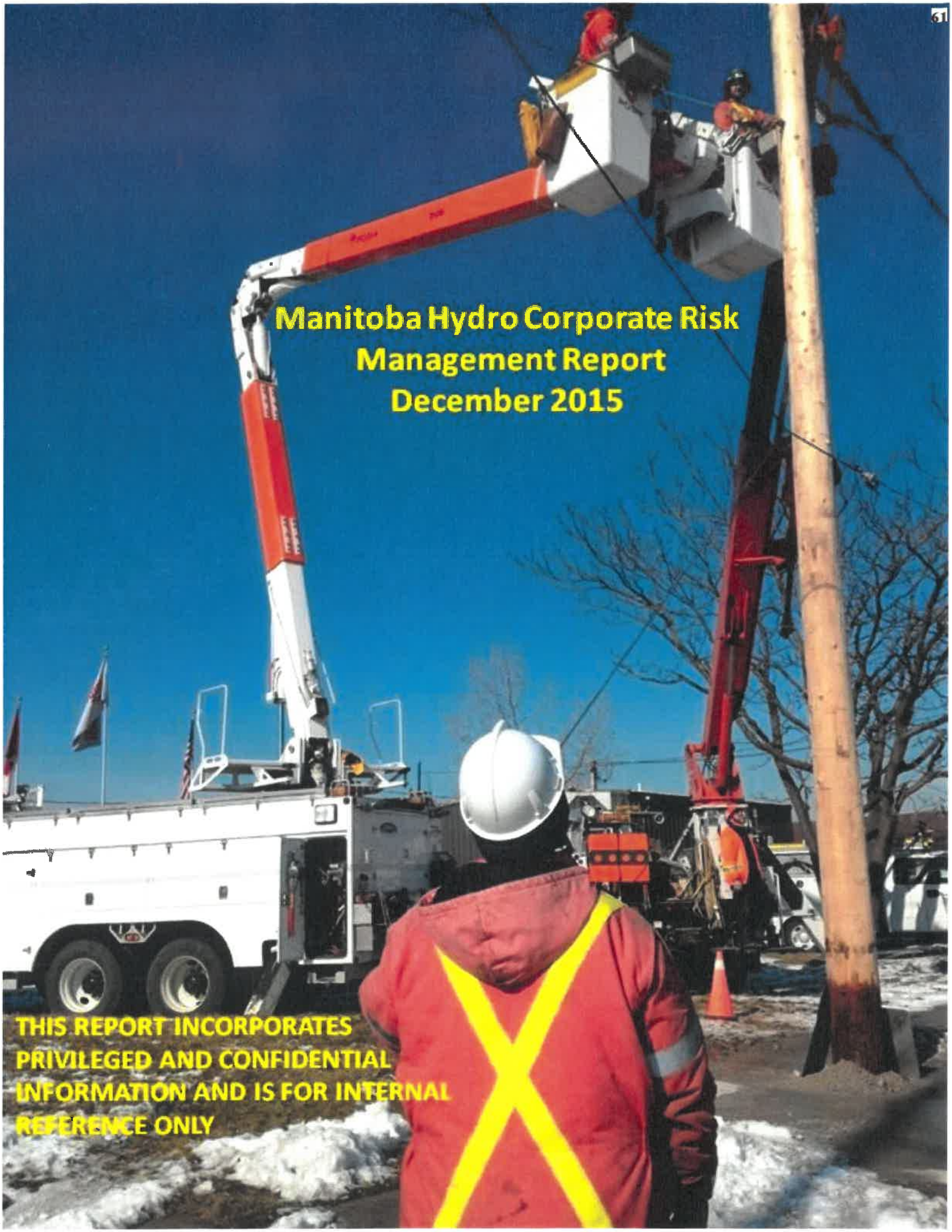
8

PUB MFR 9 (Revised)
Corporate Overview

Corporate Risk Analysis Report and Specific Risk Management Plans for all major risks including drought. [Appendix 11.7, 2015/16 GRA]

The response to PUB MFR 9 has been updated to include the redacted version of Manitoba Hydro's Corporate Risk Management Report Appendices.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro has filed a motion seeking confidential treatment of the redacted information contained in the attachment to this response pursuant to Rule 13.



Manitoba Hydro Corporate Risk Management Report December 2015

THIS REPORT INCORPORATES PRIVILEGED AND CONFIDENTIAL INFORMATION AND IS FOR INTERNAL REFERENCE ONLY

response to the 2014 rupture of the TransCanada main gas pipeline, the Corporation is constructing a compressed natural gas facility to help mitigate small scale outages during a natural gas supply interruption.

- Water retaining structures and flow control management, including: surveillance inspections, instrumentation monitoring, and engineering analyses of dams and dykes including emergency plans for individual facilities; systematic utilization of failure modes-based condition assessment techniques; and rehabilitation of the Pointe du Bois spillway facility.

- Continual improvement to enhance and strengthen the Corporate Emergency Management Program. In 2015, the Emergency Preparedness Policy was revised, and an Executive Emergency Management Committee was created to provide oversight of the program and to directly support the Corporate Emergency Center during an emergency event. In addition the Corporation continues to develop and maintain emergency preparedness and response management plans.

2.2 Water Supply Variation / Drought Risk (C.1 and D.2)

On average, there is a high likelihood of a drought occurring about once in every ten years. In the circumstances of an extreme drought that is more severe than the worst on record, there is a possibility of insufficient energy supplies being available to meet firm load demands. This would result in extreme financial and reputational impacts on the Corporation. The cost of a five year drought similar to the worst on record is estimated to be $1.9 billion (IFF 15) for a drought commencing in 2017/18.

Risk Treatment

There are several measures in place to manage the impacts of a drought, as follows:

- **Manitoba Hydro's** current generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. A drought more severe than the worst on record could occur and would require non-normal operations. This may include operating reservoirs outside of the normal range for power production. Non-normal operation may also include demand reduction measures such as public appeal for conservation, enforced conservation, or rotating reductions of non-essential load. Actions to manage drought will depend on its duration and severity and any other conditions that prevail at the time.

- Once built, the new Manitoba-Minnesota Transmission interconnection with the U.S. will provide the Corporation with increased ability to access additional amounts of energy through higher imports and through financial settlement of firm export contracts.

- Adequate financial reserves are required to protect against a repeat of the worst drought on record. At March 31, 2015 retained earnings totaled $2.8 billion. It should be noted, however, that while drought is a major quantifiable risk, an adequate level of retained earnings is required to recover from other significant risks such as a prolonged loss of supply or the loss of export market access.

2.3 Export Market Access Risk (Category A.2)

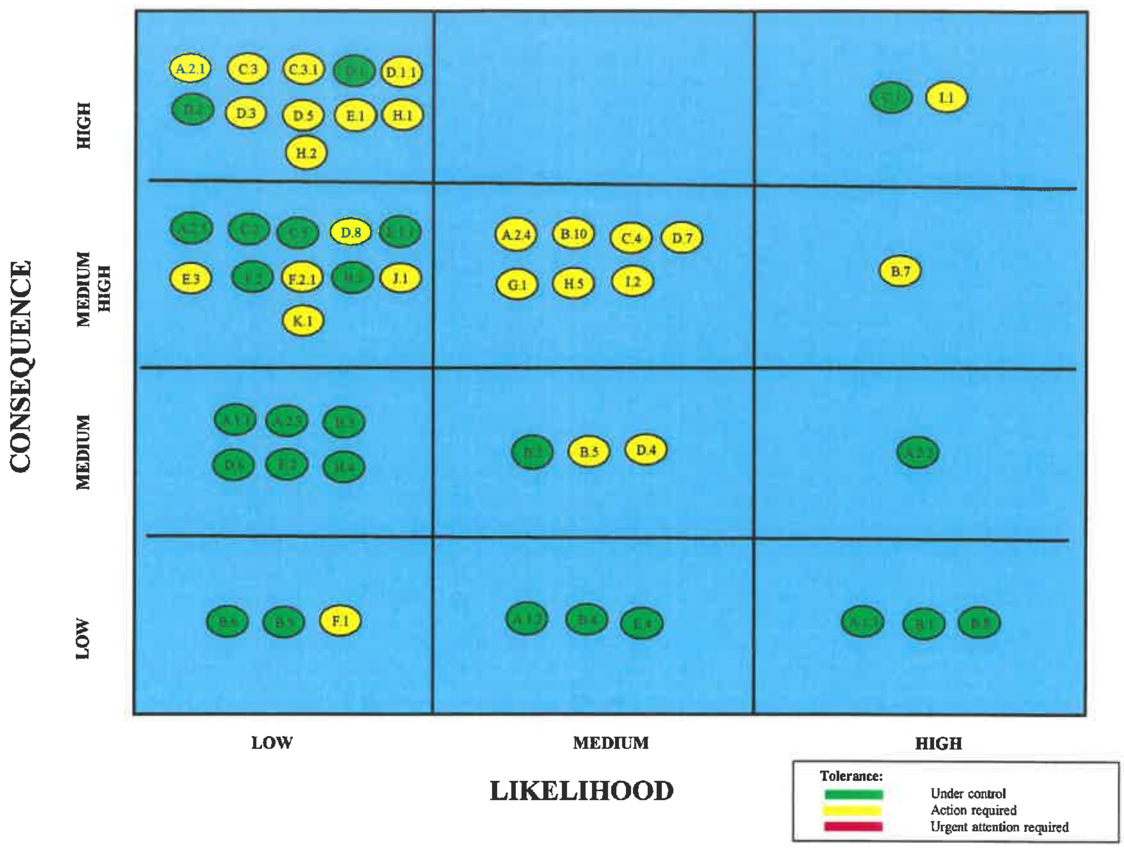
On average Manitoba Hydro derives a significant portion of its revenue from export sales to U.S. and Canadian markets. The prime impact of restricted market access would be significantly reduced net export revenues which are fundamental in keeping domestic rates low and offsetting the upfront costs of capital investments. Market access risk also includes restrictions on Manitoba Hydro's ability to import which could increase the cost of droughts, and degrade system reliability.

Risk Treatment

Manitoba Hydro continues to actively work to mitigate and manage market access uncertainties, as follows:

- In alliance with other industry participants such as the Canadian Electricity Association, and other stakeholders, Manitoba Hydro continues to lobby MISO, IESO and FERC for the development or elimination of market rules that affect electricity trade and facilitate full participation of Manitoba Hydro in US and Canadian electricity markets.

CORPORATE RISK MAP



A. Market

1. Domestic
   1. Competition
   2. Uneconomic Loads
   3. Load Growth Uncertainty
2. Export
   1. Regulatory Environment
   2. Long Term Price Uncertainty
   3. Transmission Interconnection Capacity
   4. Special Interest Groups
   5. Protectionism

B. Financial

1. Exchange
2. Interest Rates
3. Credit
4. Inflation
5. Upstream Gas Cost Uncertainty
6. Gas Derivative Instruments
7. Financial Targets
8. Energy / Fuel Price Volatility
9. Power Financial Instruments
10. Liquidity

C. Environmental

1. Water Supply Variation / Drought
2. Climate Change
3. Operational Impact and Infrastructure
   1. Legal - Species at Risk Act
4. Reliability of Supply
5. Upstream Regulation and Water Withdrawals

D. Infrastructure

1. Loss of Plant (all property, all perils)

1.1. Water Retaining Structures and Flow Control

2. Extreme Drought – Shortfall Energy
3. Prolonged Loss of System Supply
4. System Shutdown (Short Term)
5. System Shutdown (Natural Gas)
6. Technology
7. Concerned Stakeholders
8. Emergency Management Program

E. Human

1. Safety and Health
   1. Infectious Disease
2. Union / Employee Issues
3. Workforce Management
4. Technology

F. Business Operational

1. Supply Chain
2. Operational Controls
   1. Cyber Security

G. Reputation

1. Reputation

H. Governance / Regulatory / Legal

1. Regulation and Licencing
2. Export Market Access
3. Legal Compliance
4. Contracts and Ventures
5. NERC/MRO Reliability Standards

I. Indigenous

1. Relationships
2. Legal

+

J. Emerging Energy Technologies

1. Emerging Energy Technologies

K. Strategic

1. Strategic Direction and Execution

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
9. Power Financial Instruments	Low	As defined in the Wholesale Export Power Policy.	Within established guidelines.	Corporate Risk Management is finalizing the installation of risk software that will provide enhanced risk measurement capability.
10. Liquidity	Low	As per the Manitoba Hydro Act, the temporary borrowing limit shall not exceed in the aggregate the sum of $500 million.	Within established guidelines.	Cash receipts and disbursements are closely monitored on a daily basis. Short term debt balances and forecasted cash requirements are also monitored, with short term debt converted to long term debt as required. Fund three months in advance of requirements.
C. ENVIRONMENTAL				
1. Water Supply Variation / Drought	Medium	Operation Planning Criteria and adequate financial reserves. Potential 5 year drought impact is $1.9 billion for a drought commencing in 2017/18 (IFF 15)	Good water conditions that could change within a year. Sufficient retained earnings to withstand extended drought. Natural gas and power prices are expected to be low for the near-term.	Retained earnings sufficient for reduced flow/revenue due to drought.
2. Climate Change	Low	Climate change impacts expected to occur gradually	Climate change issues on water supply are being studied. Any required adaptation to operations and resource plans will be made as information becomes available.	Continue to monitor progress on determining climate change impacts and respond accordingly.

Green	Risk is being managed appropriately and is not expected to materially change.
Yellow	Some emerging issues need to be monitored and additional action may be required.
Red	Urgent attention required

Likelihood	High
Consequence	High
Tolerance	Med

CATEGORY: C. Environmental

TITLE: 1. Water Supply Variation / Drought

RISK: Reduced water supply impacts generation output

DESCRIPTION:

Variation in water (fuel) supply is a fundamental characteristic of a predominately hydro system. Actual annual hydraulic generation will vary from the long term average of all flow conditions assumed in the planning process with lower than average flows occurring approximately 40% of the time. Reduced water supply has a direct financial impact through reduced hydro generation and in turn reduced export revenues and/or the need for more expensive replacement of supply

Water Supply Variation/Drought risk is defined as a change in revenue due to deviations from average flows, under expected export market prices. The overall cost of a drought to the Corporation is a combination of this Water Supply Variation/Drought risk (i.e. volumetric risk) and the Short-Term Energy Price Volatility / Fuel Price Volatility (B.8). The possibility of a drought more severe than the drought of record is discussed in Extreme Drought-Shortfall of Energy Supply (D.2).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Reduced water supplies impact the Corporation's ability to maximize net export revenues and maintain the projected electricity rates for Manitoba customers. The severity of impacts ranges from relatively modest costs due to subtle change in the timing of inflows, up to extreme financial losses as a result of a multi-year drought. The lost revenue due to a five year drought at expected export prices was estimated to be $1.9 billion (IFF 15) including financing costs. Risk due to Energy / Fuel Price Volatility (B.8) would be in addition to this amount.

Regulation changes that limit hydraulic operating flexibility may reduce dependable energy and, consequently, reduce net export revenue and add costs due to advancement of the in-service date for new generation. Similar effects may be realized if regulation changes upstream of Manitoba or climate change impacts alter the timing or supply of flows entering the province.

RISK TREATMENT:

The Corporation intends to have adequate retained earnings to protect against a repeat of the worst recorded drought. In addition, the Corporation constantly monitors supply conditions, updates inflow forecasts, and reviews long-term weather forecasts.

At least quarterly, the Export Power Risk Management Committee (EPRMC) reviews a quantitative assessment of the current water supply conditions and any potential financial impacts resulting from variations in market prices and water supplies including the consequences of extreme drought. During periods of increased risk, the EPRMC increases the frequency of its meetings to review and approve risk tolerances, risk mitigation strategies and significant operational decisions. The Manitoba Hydro Electric Board is also kept updated in periods of increased drought risk. Energy purchase decisions are timed and distributed appropriately to protect against price risk of electricity purchases. To protect against gas price risk, purchases are structured such that a portion of the gas needs are purchased in advance, with the option to take, store or sell the fuel.

9

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

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) 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.

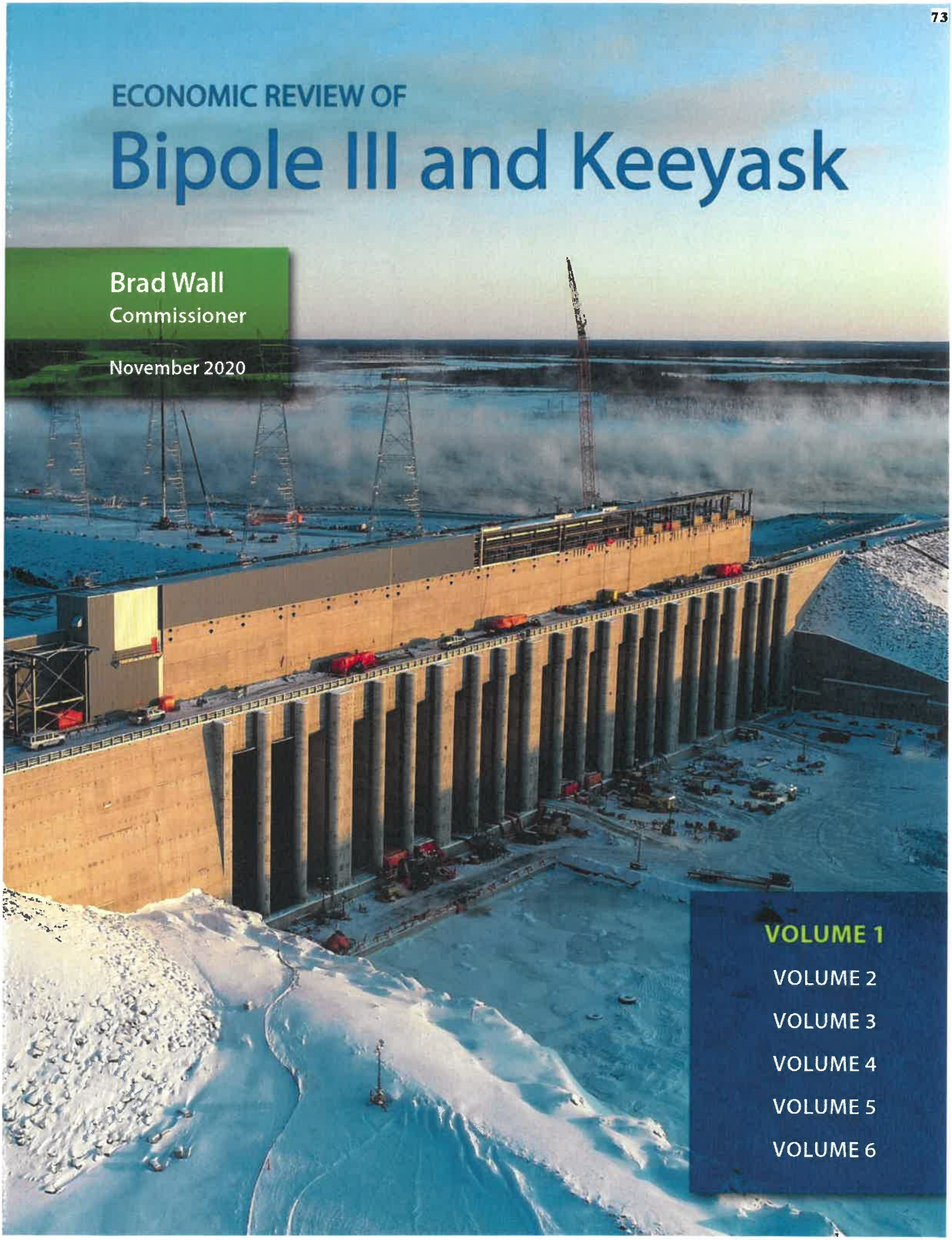
And this is a quote from DBRS, Dominion Bond Rating Service, on their report on Manitoba Hydro in September of 2013. And this, I think, is also in the book of documents; and it may be part of the cross-examination from Mr. Peters later on today. But this is from that report. This is -- indicate, actually, 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

10

ECONOMIC REVIEW OF

Bipole III and Keeyask



Brad Wall
Commissioner

November 2020

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generation. Failure to fulfill the contracts would have risked Manitoba Hydro's commercial reputation, as it argued during the NFAT in favour of approval for Keeyask.[191]

A Government of Manitoba news release from 2011 states that then-Premier Greg Selinger announced the signing of the MP and WPS export contracts by Manitoba Hydro and indicates that he said they would trigger the development of Keeyask, as follows:

> The premier said these sales will require the construction of new hydroelectric generating capacity in Manitoba. They will trigger the development of the 695-MW Keeyask (Cree for gull) Generating Station located on the lower Nelson River 175 km northeast of Thompson in the Split Lake Resource Management Area. Keeyask is to be developed by a partnership consisting of Manitoba Hydro and the Keeyask Cree Nations-Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation. The $5.6-billion project will provide some 4,500 person-years of construction employment, said Selinger.
>
> "I am very pleased that Manitoba Hydro is moving forward with these power sales which will significantly increase our exports and lead to further development of Manitoba's renewable hydro power resources," stated Selinger. "These sales will add to Manitoba's reputation as a sustainable energy leader and help reduce global greenhouse-gas emissions by reducing the need for thermal generation in the United States. At the same time, the development of Keeyask will deliver jobs, training and business opportunities to the Keeyask Cree Nations, the north and all of Manitoba."[192]

Finding #2.10: The approval of export contracts set to begin in 2020, on the understanding that new hydroelectric generation and transmission was required to serve them, created an imperative for new generation and transmission to be built and operational by 2020. This imperative constrained the decision making of both Manitoba Hydro and the NFAT Panel.

Recommendation #2.6: Manitoba Hydro's ratepayers should not bear the risk associated with new generation projects that will, for an extended period of time, be commercial in nature, used for exports, and not needed to serve domestic demand. In other words, they should not be used as involuntary equity investors for projects to serve export demand in a risky market. Since it is the Government that approves export contracts and new generation projects like Keeyask, not ratepayers, and the Government that benefits (through water rentals, capital taxes and debt guarantee fees from Manitoba Hydro) even if such projects do not turn out well financially (as discussed in Chapter 4), it is the Government that should bear this risk. Accordingly, if a Government in the future approves a generation project that is, for an extended period of time, primarily for export and not needed for domestic demand, then the Government should bear the risk if this commercial plant is not successful during that period. If the market plan fails and export revenues do not cover the costs of operating the plant during that period and the proportion of capital costs for that part of the plant's operating life, then the Government should reduce or suspend its collection of transfers from Manitoba Hydro until those cost shortfalls are made up. This will have the effect of putting government's budget at risk for decisions that are made by Government, rather than ratepayers.

The Commissioner believes that this recommendation will add accountability that will improve decision making at the government level and will provide a proper incentive to the Government of Manitoba to provide greater oversight and accountability with respect to any future major capital projects.

To implement this recommendation, Government may wish to legislate a reduction or suspension in the transfers that Manitoba Hydro is required to pay to the Government in the circumstances set out above.

191 NFAT, Exhibit MH-204, Manitoba Hydro Final Argument, pp. 285-286 [Appendix A, Tab 18].

192 Government of Manitoba, News Release, "$4 billion in power sales to U.S. for Manitoba Hydro: Selinger," May 25, 2011 [Appendix A, Tab 86].

FISCAL IMPLICATIONS OF THE PROJECTS

Government Processes

A former government staff member noted that prior to the change in government in 2016, the Treasury Board Secretariat had very limited involvement in Crown corporations. The same individual confirmed that Treasury Board did not discuss individual projects at Manitoba Hydro during their tenure.[378]

A former government staff person reported that it was not the role of the former Government's Cabinet subcommittees to review Manitoba Hydro's capital expenditures. They further noted that these expenditures were approved by the MHEB and provided to Cabinet committees as updates.[379]

In its report, BCG cited "systemic decision governance issues," including a lack of "clear objective function and criteria/constraints" among Manitoba Hydro, the PUB, and the Province, as a factor that needs to be addressed.[380]

Finding #4.17: Based on the materials that the Commission received from the Government (including Cabinet documents), there is no evidence of the former Government having formal internal processes for reviewing the financial implications of either Bipole III or Keeyask.

Finding #4.18: In the Commissioner's view, there is a need for clarification as to the respective functions, roles, and responsibilities of Manitoba Hydro and the Government as they relate to reviewing fiscal implications for major projects like Keeyask or Bipole III. The Commissioner was troubled to hear that the Treasury Board Secretariat at the time had very limited involvement in major projects at Manitoba Hydro or Crown corporations generally, especially given the Secretariat's concern about summary net debt. The Commissioner was also troubled to hear that the former Government's Cabinet subcommittees did not review Manitoba Hydro's capital expenditures and were merely provided updates. The Commissioner is encouraged to hear that Cabinet and the Treasury Board Secretariat appear to have become more involved in Manitoba Hydro's financial affairs under the current Government. This finding is addressed by Recommendation #1.2.

Recommendation #4.10: As discussed in Chapters 2 and 3 of this report, the Government should revise Manitoba Hydro's statutory mandate as set out in *The Manitoba Hydro Act* to make it clear that Manitoba Hydro's mandate is to meet Manitoba's peak domestic load in the most cost-effective manner possible and not to maximize jobs in the north or carry out the Province's environmental policy, unless otherwise directed by the Government through a transparent process. It should not preclude Manitoba Hydro from exporting power provided it is done in accordance with provincial energy policy which, as recommended in this report, should provide guidance regarding exports including commercial targets for projects built for exports (regardless of whether they eventually are used to serve domestic demand).

Financial Implications of Bipole III Routing

The Commission heard from a former elected official that no information about the cost difference of Bipole III East and Bipole III West was provided to the former Government by Manitoba Hydro, at least as of the time that the former Government mandated a route other than the east side of Lake Winnipeg. This former elected official acknowledged that Bipole III West would have been more

378 Information received from participant, March 10, 2020.
379 Information received from participant, March 24, 2020.
380 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 5 [Appendix A, Tab 22].

expensive because of its greater length, but also implied that there would be costs of longer delays associated with obtaining necessary permits on the east side (because of Indigenous opposition, among other reasons).[381]

The Commission heard a different recollection from a former Manitoba Hydro executive, who noted that the cost of routing Bipole III on the west side of the Province was presented to the Government of the day.[382] The former executive noted that the Government's response to the cost information was that they could route Bipole III any way other than down the east side of Lake Winnipeg.

Cost estimates for the various routes were included in documents provided by the Government to the Commission. According to the document with cost estimates for Bipole III West and Bipole III East that was closest in date to when the former Government mandated a route other than the eastern route (September 2007), Bipole III West was expected to cost $500 million more than the eastern route and would require $1.2 billion in converters to be advanced.[383] It is not clear what level of scrutiny these cost estimates received or what government approval process considered this cost information (if any).

In *Hansard* from September 2007, Hugh McFayden, then Leader of the Official Opposition, referenced the same cost differential for Bipole III East and Bipole III West ($500 million more for the latter) and cited a statement by Manitoba Hydro's CEO at the time, Bob Brennan, in support of the differential. In response, then Premier Gary Doer admitted that Bipole III East would have been cheaper to build given its shorter distance, as follows:

> We fully admitted that the cost of doing the west side transmission line was higher from a straight, straight-line basis. It's obviously cheaper to build a straight line than it is to have a more circuitous route. We admitted that during the campaign.[384]

In December 2007, Bob Brennan, then CEO of Manitoba Hydro, testified before the Standing Committee on Crown corporations that Bipole III West would take two years longer to complete than Bipole III East: one year because of more consultation required and another year because of the greater distance.[385]

In an op-ed in the Winnipeg Free Press in April 2008, Greg Selinger, then Minister Responsible for Manitoba Hydro, noted that the cost of Bipole III East was $1.8 billion, compared to $2.2 billion for Bipole III West based on information provided by Manitoba Hydro. Then leader of the Progressive Conservative opposition, Hugh McFadyen countered with his own article in the same paper later that month, noting that the cost quoted by Greg Selinger for Bipole III East was inflated by $1.1 billion due to the inclusion of a converter station that was not needed, making the extra cost of Bipole III West $1.5 billion, not the $400 million noted by Selinger.[386]

381 Information received from participant, July 15, 2020.
382 Information received from participant, February 26, 2020.
383 Briefing Note, Department of Finance, "Bipole III - Routing Options," November 23, 2005.
384 Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 1st Sess., Vol. 59, No. 10 (September 26, 2007) [Appendix A, Tab 6].
385 Manitoba, Legislative Assembly, Standing Committee on Crown Corporations, *Debates*, 39th Leg., 2nd Sess., Vol. 60, No. 4 (December 19, 2007) [Appendix A, Tab 134].
386 Brandon Sun, "Why the west side is the best side," April 9, 2008 [Appendix A, Tab 135]; Brandon Sun, "West side is wrong, but you don't have to take my word for it," April 12, 2008 [Appendix A, Tab 136].

Finding #4.19: The Commission heard conflicting statements about the availability of information from Manitoba Hydro to the former Government regarding the comparative costs of Bipole III East and Bipole III West. The Commission also reviewed conflicting information about the comparative costs of these routes, including those resulting from delays. However, based on the information reviewed and outlined above, it appears that, at the time the former Government mandated a route other than Bipole III East, Bipole III East would have been at least $400 million to $500 million less expensive to build than Bipole III West, largely based on its shorter distance. Any costs associated with delay likely cannot be quantified in hindsight, given the passage of time (among other reasons).

A review of *Hansard* indicates a lack of concern for Bipole III routing costs on the part of the former Government. In May 2009, concerns were raised in the Legislature regarding the soundness of the costs of building Bipole III on the west side of the Province. Greg Selinger (then Minister Responsible for Manitoba Hydro) responded by generally discussing the need for stimulus and employment in the economy which, at the time, was in the midst of a global recession.[387] This response ignored the fact that Bipole III could have been built less expensively on the east side of Lake Winnipeg while also bringing employment and stimulus to that part of the Province, where it was greatly needed.

Later that year, concerns were again raised in the Legislature regarding the cost of Bipole III West particularly to individual Manitobans. At that time, Rosann Wowchuk (the Minister Responsible for Manitoba Hydro) responded that Bipole III East would be much more expensive and would "put at risk $20-billion worth of [export] sales."[388] This claim that Bipole III East would be more expensive than Bipole III West is contrary to all of the documents reviewed by the Commission.

This $20 billion export sales figure cited by former Minister Wowchuk increased in subsequent years. In 2010, Minister Wowchuk stated that with Bipole III and new generation stations operational, revenues from hydro exports were projected to exceed $20 to $22 billion over the next two decades.[389] In 2013, Dave Chomiak (then Energy Minister) stated that Keeyask and Conawapa would "pay for themselves" because of $7 billion in firm export contracts and "another $20 billion" that were being negotiated.[390] Mr. Chomiak also stated that year that export contracts were "projected to generate $29 billion in export revenue over the next 30 years."[391]

Finding #4.20: The evidence available to the Commission suggests that the former Government gave little consideration to the cost differences between Bipole III West and Bipole III East. As discussed in Chapter 1 of this report, Bipole III East was rejected by the former Government because of its concerns with U.S.-based opposition to the route, a UNESCO World Heritage Site designation, opposition by some east side First Nations, and effects on export opportunities (which could not be substantiated), after which time the only option that was seriously considered by Manitoba Hydro was Bipole III West. This concern is addressed by Recommendation #1.2.

387 Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 3rd Sess., Vol. 61, No. 38B (May 7, 2009), p. 1790 [Appendix A, Tab 137].

388 Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 4th Sess., Vol. 62, No. 12 (December 15, 2009), p. 361 [Appendix A, Tab 138].

389 Brandon Sun, "Bipole III route best for Hydro's future," August 13, 2010 [Appendix A, Tab 139]; Brandon Sun, "Project must proceed," February 1, 2010 [Appendix A, Tab 140]; Brandon Sun, "McFadyen misses mark with Hydro comments" September 23, 2010 [Appendix A, Tab 141].

390 Winnipeg Free Press, "Hydro, gas hikes get go-ahead," April 27, 2013 [Appendix A, Tab 142].

391 Brandon Sun, "Halting hydro projects puts long-term prosperity at risk," February 12, 2013 [Appendix A, Tab 143].

Finding #4.21: As found in Chapter 3 of this report, Manitoba Hydro's (and the former Government's) export forecasts were overly optimistic given the inherent risks and uncertainties underlying Manitoba Hydro's assumptions about carbon "premiums" and demand for hydro-electric power in the U.S. export market, and the competition that Manitoba Hydro will face in the export market. At the start of the NFAT, Manitoba Hydro estimated export revenues from firm contracts of $9 billion, which fell to $6.9 billion during the NFAT and even lower afterwards with the cancellation of its largest contract, the WPS 308 MW sale (as discussed in Chapter 3 of this report).

Manitoba Hydro Internal Processes

Manitoba Hydro's IFFs speak of financial implications of its major projects along with other estimates and assumptions about the future that are subject to change. The IFFs show an evolving forecast of impacts on borrowing, as well as some passing references to impacts on rates, but the issue is reported as an outcome of Manitoba Hydro's development plan as opposed to an important implication to be considered in determining the appropriateness of that development plan relative to alternatives.

Manitoba Hydro's November 2008 IFF08-1 included a PUB-approved 5% electricity rate increase in 2008 and 4% (conditional) increase in 2009, followed by annual increases of 2.9% per year starting in 2010. It was forecasted that Manitoba Hydro would achieve its target debt/equity ratio (75/25) by the end of 2008/09 and maintain it until 2014/15, "when capital expenditure levels begin to grow as a result of the construction of Keeyask, Conawapa and Bipole III."[392] Manitoba Hydro's 20-Year Financial Outlook released shortly thereafter projected that Manitoba Hydro would again achieve its target-debt equity ratio (after capital expenditures associated with major projects) by 2024.[393] Drought was noted as a major risk in both documents, and interest rates and foreign exchange, export prices, domestic load growth, and increased capital costs were also noted in IFF08-1. Citing IFF08-1 and its proposed rate increases, one former Manitoba Hydro executive concluded and advised the MHEB that it would be possible for Manitoba Hydro to build Keeyask and Bipole III (among other planned projects) without undue negative impacts on financial ratios.[394] This advice was based on extra-provincial revenue estimates and project capital cost estimates at the time, which proved too high in the case of the former and too low in the case of the latter. The presentation with this advice was received as information during a meeting of the MHEB.[395]

In its report, BCG noted that the decision to build Keeyask was imprudent "due to a failure to fully assess the risks" including:

- Financial modelling that did not fully reflect the specific project risks (e.g., construction execution, market prices, domestic demand);
- Discount rates that favoured high capital projects over lower upfront cost projects; and
- The magnitude of the overall level of debt that both Manitoba Hydro and the Province of Manitoba would ultimately be exposed to, especially given the concurrent build of Bipole III.[396]

The BCG report further noted that risks such as these have "adversely impacted the economics of the projects and continued to put Hydro into a more and more difficult financial position, making construction of Keeyask and the tie-line in particular an even more questionable decision."[397]

392 Manitoba Hydro, Integrated Financial Forecast (IFF08-1), November 2008, p. 15 [Appendix A, Tab 144].
393 2010/11 GRA, Appendix 16, p. 6, Figure 3 [Appendix A, Tab 145].
394 Vince Warden, Vice-President, Finance & Administration and Chief Financial Officer, Manitoba Hydro, "20 Year Financial Forecast," August 14, 2008.
395 Minutes of MHEB Meeting, August 20, 2008.
396 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 2 [Appendix A, Tab 22].
397 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 3 [Appendix A, Tab 22].

Sanford Riley, then Chair of the MHEB, accepted BCG's findings in September 2016 but concluded that the projects were too far along to cancel.[398]

Finding #4.22: As BCG's review made clear and the MHEB accepted, the decision to build Keeyask was imprudent due to a failure to fully assess the risks, including its fiscal implications and the level of debt that both Manitoba Hydro and the Province would ultimately be exposed to, especially given the concurrent build of Bipole III. The degree of risk was attendant on export market forecasts (which, as discussed in Chapter 3, were overly optimistic) and executing Keeyask and Bipole III on budget, which did not happen.

Recommendation #4.11: The decision to build a project of the scale and cost of Keeyask should not be made until after the risks have been fully assessed, including the project's immediate and long-term fiscal implications for Manitoba Hydro (and its ratepayers) and the Province (and its taxpayers). As recommended in Chapter 1 of this report, the need for a project should be justified through comprehensive IRP completed by Manitoba Hydro and then reviewed by an independent regulator such as the PUB in a public proceeding.

Under Bill 35, the required NFAT of a major new facility should also include a full assessment of risk and fiscal implications.

One former executive of Manitoba Hydro suggested that Manitoba Hydro should develop an internal finance area that more rigorously evaluates capital expenditures and project justifications. The former executive stated that major projects were a historic issue for the company and recommended that the internal finance area should have staff with wide-ranging expertise to determine the best ways to proceed with these projects based on financial implications. They noted that, in the case of Keeyask, a dichotomy developed whereby engineers at Manitoba Hydro were generally in favour of the project whereas those in finance advised against it.[399]

In its response to MGF's report, Manitoba Hydro noted that in 2016 it established the MPEC comprising Manitoba Hydro's President and CEO as well as five vice- presidents with accountability over the areas of the company responsible for the execution of major capital projects. The MPEC was established to provide oversight, direction, and strategic decision making with respect to Keeyask, Bipole III, the Manitoba Minnesota Transmission Project (**"MMTP"**), and the **Great Northern Transmission Line** project in Minnesota.[400]

Finding #4.23: Based on the decision to proceed with Keeyask despite the concerns of Hydro's finance staff, it appears that Manitoba Hydro's internal processes and decision-making structures placed a greater emphasis on the input of the engineers over other disciplines such as finance.

Recommendation #4.12: As discussed in Chapter 5, the Commissioner views Manitoba Hydro's establishment of the MPEC as a good decision and a positive development in terms of project oversight, coordination, and accountability within Manitoba Hydro. The MPEC or a structure with similar, direct executive involvement (including the President and CEO) should be in place at the beginning of any future large-scale capital project at Manitoba Hydro. Such a structure helps provide clear lines of responsibility and executive oversight within the company.

398 Winnipeg Free Press, "Hydro board slams handling of Bipole III, Keeyask dam projects – but says it's too late," September 21, 2016 [Appendix A, Tab 146].

399 Information received from participant, February 18, 2020.

400 2017/18 GRA, Exhibit MH-117, p. 13 [Appendix A, Tab 130].

PUB Processes

Financial Targets

Incorporating the capital costs of Keeyask and Bipole III (as forecasted at the time), financial modeling during the NFAT considered what the rate trajectories of different development plans would have to be to reach Manitoba Hydro's 75/25 debt/equity target in 18 years (i.e., by 2031/32, the same timeline in the aforementioned 2015 Corporate Risk Management Report).[401] This was done using Manitoba Hydro's 20-year IFF as well as longer-term rate trajectories.[402] In the case of Plan 6 (Keeyask and the 750 MW interconnection, the development plan that is currently proceeding), equal annual rate increases of 3.75% were projected until 2031/32 achieve the target. In its report, the NFAT Panel recommended relaxing the debt/equity target to mitigate such rate increases.[403]

During the 2017/18 GRA, Manitoba Hydro requested 7.9% rate increases to achieve a 75/25 debt/equity level in 10 years (i.e., by 2026/27, not by 2031/32 as in the NFAT). Instead, the PUB approved a 3.36% interim rate increase and a 3.6% rate increase in 2018,[404] based on a consideration of the interests of Manitoba Hydro's ratepayers and the financial health of Manitoba Hydro (as required by the PUB's mandate).[405] This most closely approximated a rate scenario of annual 3.57% rate increases to achieve the target debt/equity ratio by 2035/36.[406]

During the 2019/20 electric rate application, Manitoba Hydro requested a 3.5% interim rate increase to avoid a projected net loss of $28 million from electrical operations in 2019/20. While Manitoba Hydro did not update its long-term financial forecast, it noted that, even if the requested 3.5% rate increase in 2019/20 was granted, its cumulative earnings from 2017/18 to 2019/20 would be almost $200 million less than it assumed during the 2017/18 GRA. It further noted that those lower-than-expected financial results would exacerbate the longer-term losses projected during the 2017/18 GRA.[407] The fact that the requested 3.5% increase was not granted (a 2.5% increase was granted instead, with all revenues therefrom to be placed in a deferral account for major capital projects under construction)[408] would have only further exacerbated those projected losses. Absent consistently higher rate increases than the 3.57% annual increase projected during the 2017/18 GRA, those increased losses over the longer term would lead to a later recovery to the targeted 25% equity ratio than was projected during the 2017/18 GRA (i.e., later than 2035/36).[409]

In its report to the PUB as part of the review of Manitoba Hydro Financial Targets and the 2017/18 GRA, MPA concluded that the debt/equity ratio should not be the primary financial target that is taken into

401 NFAT Report, p. 169 [Appendix A, Tab 15]; NFAT, Exhibit MH-111, p. 36 [Appendix A, Tab 147].
402 NFAT Report, p. 168 [Appendix A, Tab 15].
403 NFAT Report, p. 191 [Appendix A, Tab 15].
404 PUB Order No. 59/18, p. 266 [Appendix A, Tab 34].
405 PUB Order No. 59/18, p. 43 [Appendix A, Tab 34].
406 2017/18 GRA, Exhibit MH-93, p. 4 [Appendix A, Tab 148]; PUB Order No. 59/18, p. 173 [Appendix A, Tab 34].
407 2019/20 Electric Rate Application, pp. 2, 4 [Appendix A, Tab 149].
408 PUB Order No. 69/19, p. 3 [Appendix A, Tab 82].
409 2019/20 Electric Rate Application, pp. 2, 4 [Appendix A, Tab 149].

account when setting rates for the future, largely on the basis that it is not the focus of capital market observers:

> This emphasis on capital structure is not shared by capital market observers, who instead are more focused on measures of cash flow sufficiency to meet debt obligations, in keeping with their primary interest of protecting their debt investments. While capital structure is an important consideration, it is nevertheless secondary in credit analysis, and only indirectly sheds light on financial risk. This suggests that if preventing negative impacts on the credit rating of the Province of Manitoba is a concern, then pursuing a Debt : Equity ratio is a secondary way of doing so. Instead, a more direct focus on ensuring cash flow sufficiency through rate-setting would be more likely to provide that support. However, lest the importance of stability and predictability be forgotten, the need to ensure the support of the capital markets for Manitoba Hydro should be balanced against the need to avoid wildly swinging rates. Cash flow sufficiency need not be an annual condition, but can rather be ensured on a rolling forward basis, which will help to manage both the predictability of rates, and the sufficiency of cash flows.[410]

MPA also described issues with debt/equity targets in terms of rate stability and predictability and changing variables:

> However, if it is determined that Debt : Equity Ratio should be a primary focus, then the question arises whether the goal of meeting the target in 2027 is appropriate.
>
> A glaring issue with this goal, even in a scenario where all reference assumptions were to prove miraculously accurate, is that in the year following the achievement of the target a very significant rate decrease would be warranted, otherwise the target would be substantially exceeded in short order. This casts into doubt the value of this timing goal from the perspective of rate stability and predictability, and also from the perspective of cash flow stability and predictability.
>
> Manitoba Hydro stated in the risk assessment included in the original application that a 7.9% rate path would have a 50% probability of achieving the Debt target by 2027, in the face of a variety of uncertain variables... No clarity was provided about which variables would be allowed to undermine the reaching of that goal, and how they would relate to rate-making. For example, interest rates have already risen somewhat, presumably reducing the probability of reaching the goal: what should be the rate response, if any? A fixed target for a specific date, which does not take into account changing variables and contexts, and is not adjustable and related to real drivers of rate-making policy, does not appear credible.[411]

MPA further questioned the prioritization of "equity" in financial targets for Manitoba Hydro, as follows:

> As a pure cost recovery, government-owned utility, it is not clear why "equity" should be a priority per se. From the perspective of the ratepayers who are the ultimate funders of all of the utility's operations, "equity" is essentially "dead money": it earns no return, but nevertheless has been taken out of the hands of the ratepayers who could otherwise use it. A review of rate paths through the lens of discounting at the social discount rate helps to stress the importance of making use of ratepayer funds in the most economical way.[412]

410 2017/18 GRA, Exhibit CC-17, p. 55 [Appendix A, Tab 150].
411 2017/18 GRA, Exhibit CC-17, p. 56 [Appendix A, Tab 150].
412 2017/18 GRA, Exhibit CC-17, p. 55 [Appendix A, Tab 150].

KPMG LLP ("**KPMG**") was retained by the MHEB to undertake a review of Manitoba Hydro's current financial targets prior to the 2017/18 GRA. KPMG recommended that the primary measure of Manitoba Hydro's financial position should remain the debt/equity ratio. Specifically, it recommended Manitoba Hydro should maintain a long-term debt/equity target in the range of 75/25 to 70/30 with a minimum of 85/15 during major capital programs, for the following reasons:

> 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...
>
> 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.[413]

KPMG also recommended that Manitoba Hydro should maintain a minimum EBITDA interest coverage ratio target of 1.8 or greater and a minimum capital coverage ratio target of 1.2 or greater. Regarding the former, KPMG stated:

> 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.[414]

Regarding the minimum capital coverage ratio target of 1.2 or greater, KPMG stated:

> 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.[415]

As part of its review, KPMG compared average residential prices of electricity to those in cities in other provinces and nearby states, which showed that Manitoba had the second lowest prices in the country

413 2017/18 GRA, Appendix 4.5, pp. 7-8 [Appendix A, Tab 151].
414 2017/18 GRA, Appendix 4.5, p. 8 [Appendix A, Tab 151].
415 2017/18 GRA, Appendix 4.5, p. 8 [Appendix A, Tab 151].

for residential consumers (next to Quebec). The average price for residential customers in Winnipeg was 9.75 cents per kWh, compared to an average of 14.1 cents per kWh among the 12 Canadian cities that were compared.[416]

KPMG also compared the financial targets/plans of Government-owned power utilities in Canada, including Manitoba Hydro which showed that, like Manitoba Hydro, the following utilities also have a debt/equity target:

- BC Hydro (65/35);
- Hydro-Quebec (75/25);
- Nalcor [Newfoundland/Labrador] (70/30); and
- NB Power (70/30).

KPMG noted that the only other public power utility with an EBITDA interest coverage ratio target is Nalcor, whose target is 1.5 or greater (compared to Manitoba Hydro's target of 1.8 or greater), and that no other public utility has a minimum capital coverage ratio target.[417]

A former Manitoba Hydro executive told the Commission that, rather than a debt/equity ratio, a more apt financial target could be determined by identifying and quantifying the risks that Manitoba Hydro faces and the equity that Manitoba Hydro needs to meet them. Then other measures regarding cash flow (e.g., EBITDA) would follow, which would measure the cash flow that assets are generating for Manitoba Hydro. The former executive expressed the belief that while a debt/equity target is convenient to explain to credit agencies and the PUB how Manitoba Hydro will build up equity and to show progress, such a target as a standalone target (i.e., independent of an assessment and quantification of risks) is the wrong approach.[418]

The PUB has also recently questioned the debt/equity metric and accepted MPA's evidence, as follows:

> The Board accepts Morrison Park Advisors' evidence that debt-to-equity is a questionable metric for a vertically integrated monopoly Crown utility with a debt guarantee from the provincial government. The equity level target does not have the prominence suggested by Manitoba Hydro given the context in which the Utility operates. The concern regarding the value of the equity level target is compounded when Manitoba Hydro is going through an unprecedented major investment period to more than double the value of its assets in the next four years. As noted by Manitoba Hydro's external consultant KPMG, there is a "practical recognition that this target will not be met during a period of large capital expenditures when newly constructed assets are placed in service. Accordingly, the 75/25 could remain the long term objective." The Board supports this view.... As such, the Board is not prepared to look at the issue of pacing to achieve a particular equity level target at least until the current phase of major capital construction is completed, now projected by Manitoba Hydro to be in 2024.[419]

The Commission is aware of cases in which the Province of Manitoba has experienced credit downgrades from two rating agencies, both of whom have tied the finances of Manitoba Hydro to the

416 2017/18 GRA, Appendix 4.5, p. 41 [Appendix A, Tab 151].
417 2017/18 GRA, Appendix 4.5, p. 48 [Appendix A, Tab 151].
418 Information received from participant, February 13, 2020.
419 PUB Order No. 59/18, pp. 63-64 [Appendix A, Tab 34], as cited in PUB Order No. 69/19, p. 28 [Appendix A, Tab 82].

Province's rating. In the case of its July 2017 downgrade of the Province's rating (from "AA-" to "A+"), Standard and Poor's noted the following in its ratings report about Manitoba Hydro:

> Our assessment of the province's debt burden fully incorporates the debt on-lent to MHEB, which accounts for more than 40% of total tax-supported debt and for which the province expects to borrow heavily to finance capital projects over the next several years. We do not view MHEB as self supporting due to its very high and rising leverage.[420]

Moody's downgraded the Province's rating in August 2014 and, in a subsequent report, noted the following concern about Manitoba Hydro's finances:

> The province issues debt on behalf of its wholly-owned electric utility company Manitoba Hydro. Given its steady revenue stream that generates sufficient cash flow to support operations including interest payments, we view Manitoba Hydro as a self-supporting entity and therefore exclude the related debt from our debt metrics of the province.
>
> We note, however, that Manitoba Hydro's total reported debt net of sinking of funds has risen considerably, doubling from CAD6.9 billion at March 31, 2008 to an estimated CAD14.2 billion as of March 31, 2016. We expect that its debt will continue to rise over the medium-term as the utility moves forward with construction projects, including the Keeyask hydroelectric station and the Bipole III transmission line, in anticipation of demand increases over the next few years and in order to boost electricity exports. The anticipated increase in debt continues to pressure the province's rating since it raises the contingent liability of the province.[421]

Finding #4.24: The Commissioner notes that other government-owned power utilities in Canada continue to use debt/equity targets which are not materially different from Manitoba Hydro's current 75/25 target. In the Commissioner's view, a long-term debt/equity target has value by helping prevent negative impacts on the Province's credit rating, particularly during adverse developments like the COVID-19 pandemic. However, achievement of a debt/equity target should not be the singular focus and an interest coverage ratio target should also be used. The Commissioner recognizes that in the short-term, aggressive debt/equity targets can have a negative impact on rate stability and predictability and, therefore, cash flow stability and predictability. The Commissioner further recognizes that financial targets must take into account changing variables and context and be adjustable based on real drivers of rate-making policy, including risks.

Government Transfers

In the NFAT, the PUB considered returns to the Government from Keeyask in the form of debt guarantee fees, capital taxes, and water rentals.[422] Evidence regarding transfers to the Province from Bipole III and Keeyask was also before the PUB in the 2017/18 GRA.[423]

The evidence in those proceedings was that no matter how the projects turned out financially, the Province would receive annual transfers from Manitoba Hydro in the form of debt guarantee fees, capital taxes, and (in the case of Keeyask) water rentals. These amounts of these transfers were estimated to be up to:

- $143 million annually (declining over time) related to Keeyask; and
- $74 million annually (declining over time) related to Bipole III.[424]

420 2017/18 GRA, Appendix 4.5, p. 53 [Appendix A, Tab 151].
421 2017/18 GRA, Appendix 4.5, pp. 54-55 [Appendix A, Tab 151].
422 See, for example, NFAT Report, p. 225 [Appendix A, Tab 15].
423 2017/18 GRA, Information Request (IR) PUB/MH I-21 [Appendix A, Tab 152].
424 2017/18 GRA, Information Request (IR) PUB/MH I-21 [Appendix A, Tab 152].