REFERENCE:

Appendix 7 p. 63; CSI MNG&T Quarterly Report for July to September 2018

PREAMBLE TO IR (IF ANY):

At page 63 of 81 of Appendix 7.1, Manitoba Hydro states that the fourth and final synchronous condenser is not yet installed as of September 30, 2018. In the CSI version of this report, the synchronous condensers contract has a contract value of [redacted], actual spending to September 30, 2018 of [redacted], and a forecast at completion of [redacted]. 1a, 7a, 8a

QUESTION:

Explain why the forecast at completion amount [redacted] and how the remaining costs related to the work to install the fourth synchronous condenser will affect the forecast at completion amount. 1a, 7a, 8a

RESPONSE:

The actual spending to September 30, 2018 of [redacted] for the synchronous condenser contract represents all accrued costs on the Contract. [redacted]. 1a, 7a, 8a 1a, 7a, 8a

The contract value of [redacted] and the forecast at completion of [redacted]. In this case, due to timing of the report, the synchronous condenser contract includes [redacted] 1a, 7a, 8a 1a, 7a, 8a [redacted]. 1a, 7a, 8a

Construction of the fourth and final synchronous condenser at the Riel Converter Station is now complete and was turned over to Manitoba Hydro for commercial service on November 17, 2018. The costs for the 4th synchronous condenser were almost entirely accrued and included in the contract value and the forecast at completion for the synchronous condensers contract reported in the Bipole III Project Update for the quarter ending September 30, 2018 filed in confidence with the PUB. As such, there is no impact anticipated to the forecast at completion related to the completion of the 4th synchronous condenser.

REFERENCE:

PREAMBLE TO IR (IF ANY):

QUESTION:

Confirm that Manitoba Hydro's evidence given in 2017/18 & 2018/18 GRA ("2017/18 GRA") proceeding and hearing is accepted as evidence in the 2019/20 proceeding, except where modified or changed in the 2019/20 evidence.

RESPONSE:

Not confirmed. The 2017/18 & 2018/19 GRA was based upon a long-term financial forecast which has not been endorsed by Manitoba Hydro's current Board of Directors, and may not be consistent with the outcome of the comprehensive review to be undertaken by the Board of Directors.

The evidence in support of Manitoba Hydro's 2019/20 Electric Rate Application is contained in the filing dated November 30, 2018 and in the further material filed in support of this request including correspondence to the PUB and responses to Information Requests. As discussed with Board Counsel, should the PUB wish to consider specific documents which were filed by Manitoba Hydro as part of its evidence in the 2017/18 & 2018/19 GRA in connection with the current Application, Manitoba Hydro respectfully requests that those specific documents be put to Manitoba Hydro for review and adoption as part of the evidence in support of the 2019/20 Electric Rate Application.

REFERENCE:

Order 59/18 pg. 264-265

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the status and details of Manitoba Hydro's efforts to address Recommendations to Manitoba Hydro Nos. 4, 5, 6, 7, and 8.

RESPONSE:

Recognizing that the subject matter of the aforementioned recommendations are not within the jurisdiction of the PUB, Manitoba Hydro offers the following comments:

Recommendation 4 suggests that Manitoba Hydro …"*Make efforts to find further areas to reduce O&A costs, both in terms of staff reductions and Supply Chain Management, after the Voluntary Departure Program transition concludes*. As noted at page 29 of the Application, the Voluntary Departure Program targets a workforce reduction of 900 employees by March 31, 2020. Further, as noted in the Annual Report filed as Appendix 3 to the Application, O&A savings continue to be developed through initiatives such as the Supply Change Management Program and the Strategic Sourcing Initiative. Manitoba Hydro is of the view that further staff reductions are not possible while still maintaining reasonable levels of service, maintenance levels, as well as managing the operations of the business. Please see Manitoba Hydro's response to PUB/MH I-17 for a discussion of cost savings to be realized as a result of the Supply Chain Management Initiative and Strategic Sourcing Initiative and the response to PUB/MH I-20 for a discussion of how Manitoba Hydro is limiting the growth in O&A expense to 2% per year going forward.

With respect to Recommendations 5 - 8 regarding capital project planning and approval, and the recommendation to engage external consultants in considering the process, Manitoba Hydro has reviewed the recommendations of MGF, some of which are addressed in the update on Directives contained in its November 12, 2018 correspondence. In addition, the Manitoba government has appointed Gordon Campbell to review the planning and decision-making processes relating to the Keeyask Generation Project and Bipole III Transmission and Converter Stations Project. Manitoba Hydro understands the Recommendations 5 – 8 referenced above to be focused on the planning and approval of major projects, such as Keeyask, Bioole III and Manitoba-Minnesota Transmission Project. Manitoba Hydro is not presently engaged in the planning and approval phases of any further projects. These recommendations may be considered at the commencement of planning of a future major capital project.

With respect to Recommendation 8 regarding recommendations made by MGF to improve Manitoba Hydro's execution of its existing projects, the recommendations proposed by MGF Project Services during their review of the Keeyask Project were primarily focused on improving outcomes of the General Civil Works Contractor ("GCC") with the goal of achieving the control budget of $8.7 billion and the control schedule first unit In-Service Date of August 2021. MGF recommended, among other things, closer collaboration on execution planning and oversight of the GCC's construction management by Manitoba Hydro and use of the contract to manage the GCC's performance. In January 2018, at the General Rate Application hearings, Manitoba Hydro outlined how it intended to work with the GCC to improve performance and achieve the plan for the 2018 construction season (the 2018 plan) and ultimately deliver the project within the revised control budget of $8.7B and related schedule. The intended approach laid out by Manitoba Hydro aligned with the closer collaboration on execution planning and oversight of the GCC recommended by MGF as well as working with the GCC to develop an achievable plan in 2018 based on production experienced to date.

Manitoba Hydro has increased the pressure on the GCC to perform, and has collaborated wherever possible to stimulate greater productivity. The effort invested by Manitoba Hydro and the GCC over the last two years to improve production and productivity is yielding results. The Project has met all the 2018 major milestones and exceeded concrete and earthworks plans for the year, setting the stage for schedule improvement that will reduce the overall cost. Although significant project risks remain, the progress to date has been positive and the necessary improvements to achieve the control budget of $8.7B are being realized and the first unit In-Service Date ("ISD") is currently trending ahead of the control schedule. Please see Manitoba Hydro's response to PUB-MH I-55a&b for additional information.

REFERENCE:

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide details of Manitoba Hydro's consultations with ratepayers with respect to the rate increases sought in this application, including copies of any public presentations.
b) Provide any documentation of outreach sessions with or surveys of Manitoba Hydro's customers demonstrating their preferences for trade-offs between rate increases and improved reliability performances.
c) Include copies of analysis and reports of the impact of any proposed rate increases on the Manitoba economy, each of Manitoba Hydro's customer classes/sub-classes, lower income customers, Manitoba Hydro's delinquent customers, and Manitoba Hydro's bad debt allowance.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro interacts with customers in many ways to provide information on matters related to the corporation and to provide customers with opportunities to provide feedback. Examples of these activities undertaken by the Corporation are as follows:

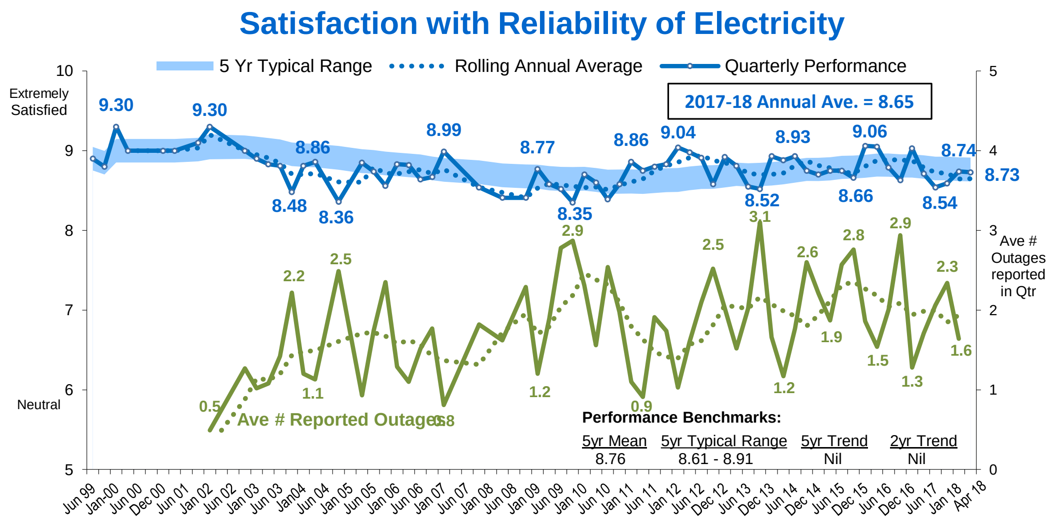
- Manitoba Hydro will be conducting three public information sessions in the Pas, Steinbach, and Winnipeg on March 13, 19, and 21, 2019 respectively. Topics will include a high level overview of the corporation's electric and gas operations, and customer billing and payment options. In addition, information on the working relationships between Manitoba Hydro and Indigenous communities, Manitoba Hydro's major projects, and its current activities throughout the Province will also be provided.

- Manitoba Hydro's Customer Contact Center staff is available Monday to Friday to answer any questions that customers may have on proposed rate increases. In addition, Manitoba Hydro Major and Key Account staff are available to answer any questions from Manitoba Hydro's large electric customers.
- Manitoba Hydro's activities, projects and electricity rates are subject to discussion at the Legislative Assembly of Manitoba sessions, and Manitoba Hydro provides updates and responds to questions related to activities, rate increases and ongoing regulatory processes before the Standing Committee on Crown Corporations.
- Manitoba Hydro also responds to a number of media inquiries with respect to the need for rate increases, as well as written inquiries from rate payers.

b) Manitoba Hydro has not undertaken research specifically investigating preferences for tradeoff between rate increases and improved reliability performance among its customers.

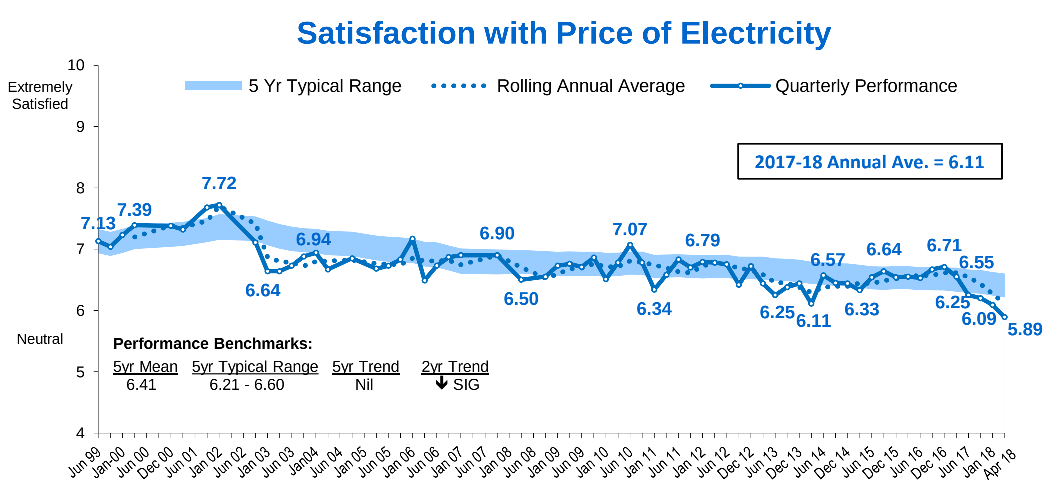
Manitoba Hydro monitors residential customer satisfaction with all aspects of its service including Reliability of Electricity and Price of Electricity through its Customer Satisfaction Tracking Study (CSTS). Reliability of Electricity continues to receive high satisfaction scores. Typically 90% or more of respondents report a score of 7 or higher on a 1-10 scale. At the end of the 2017/18 fiscal year, respondents report an average satisfaction score with Manitoba Hydro's Reliability of Electricity of 8.73, as in Figure 1 below. Manitoban's satisfaction with Reliability of Electricity ranks among the leading provinces in Canada based on annual national research done by the Canadian Electric Association.

Figure 1. Satisfaction with Reliability of Electricity (CSTS Survey)



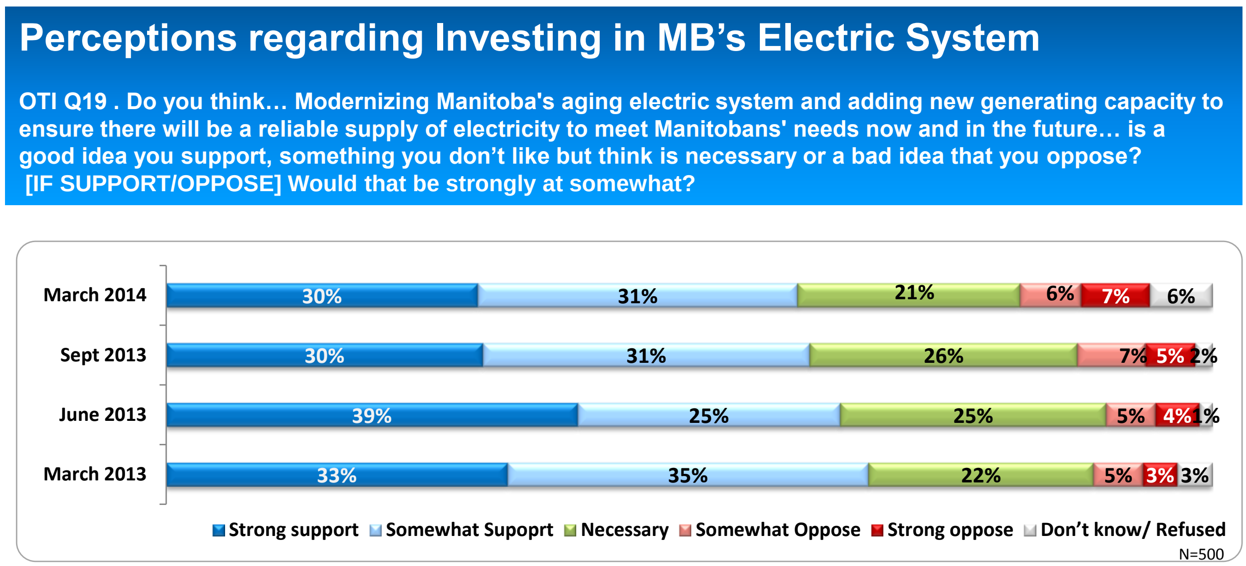
Price of Electricity typically receives satisfaction scores of 7 or higher from about 55% of respondents. This declined during 2017/18 to an annual average of 47%, with respondents reporting an average satisfaction score at the end of the 2017/18 fiscal year with Manitoba Hydro's Price of Electricity of 5.89, as shown in Figure 2. Manitobans' perceptions of the reasonableness of the Price of Electricity also ranks among the leading provinces in Canada based on annual national research done by the Canadian Electric Association.

Figure 2. Satisfaction with Price of Electricity (CSTS Survey)



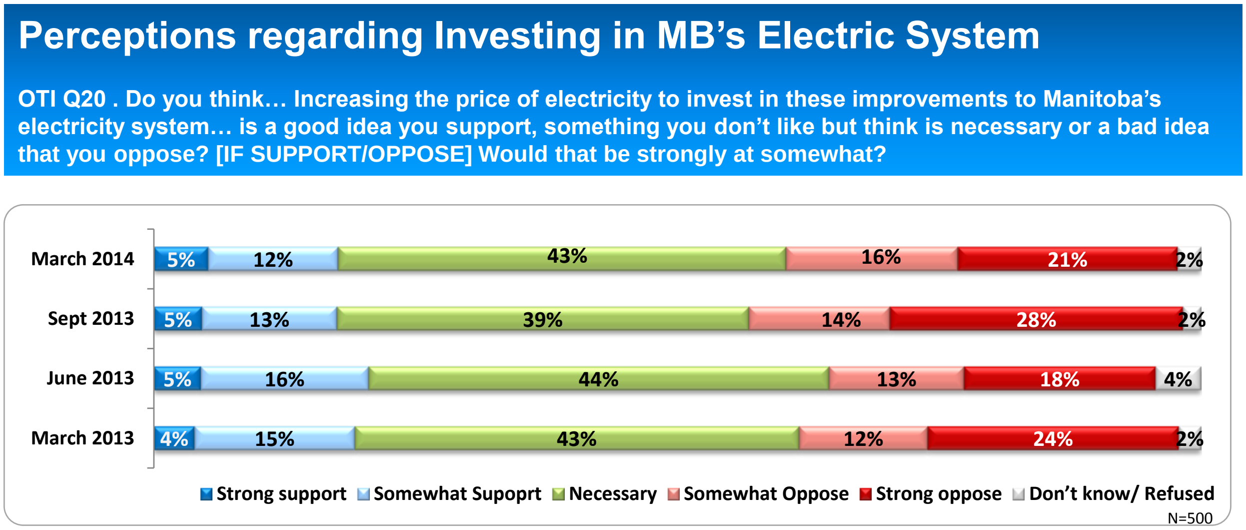
In 2013/14, Manitoba Hydro conducted research regarding Manitobans' perceptions of the need to reinvest in Manitoba's electric infrastructure. Key findings from the March 2014 survey research are illustrated in the Figures below.

Figure 3. Perceptions on Investing in Electric Infrastructure (2014 Survey)



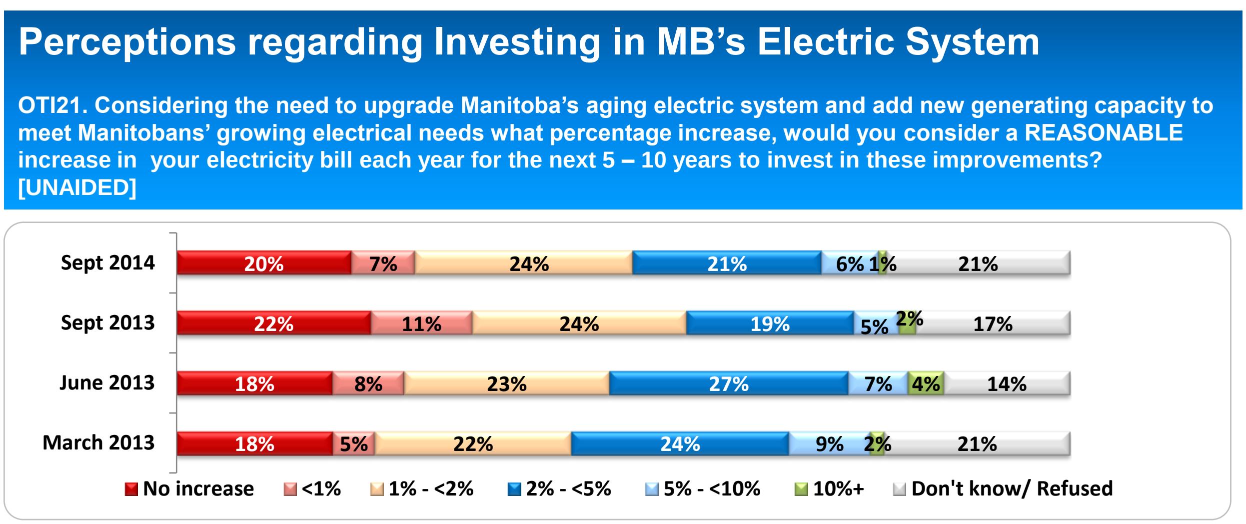
Most respondents (82%) supported modernizing Manitoba's aging electric system and adding new generating capacity to ensure there will be a reliable supply of electricity to meet Manitobans' needs now and in the future. This includes 61% who outright ("strongly" or "somewhat") supported this and 21% who "reluctantly" supported this (dislike the idea but believe upgrades are necessary). Only 13% strongly or somewhat opposed this.

Figure 4. Perceptions on Investing in Electric Infrastructure (2014 Survey)



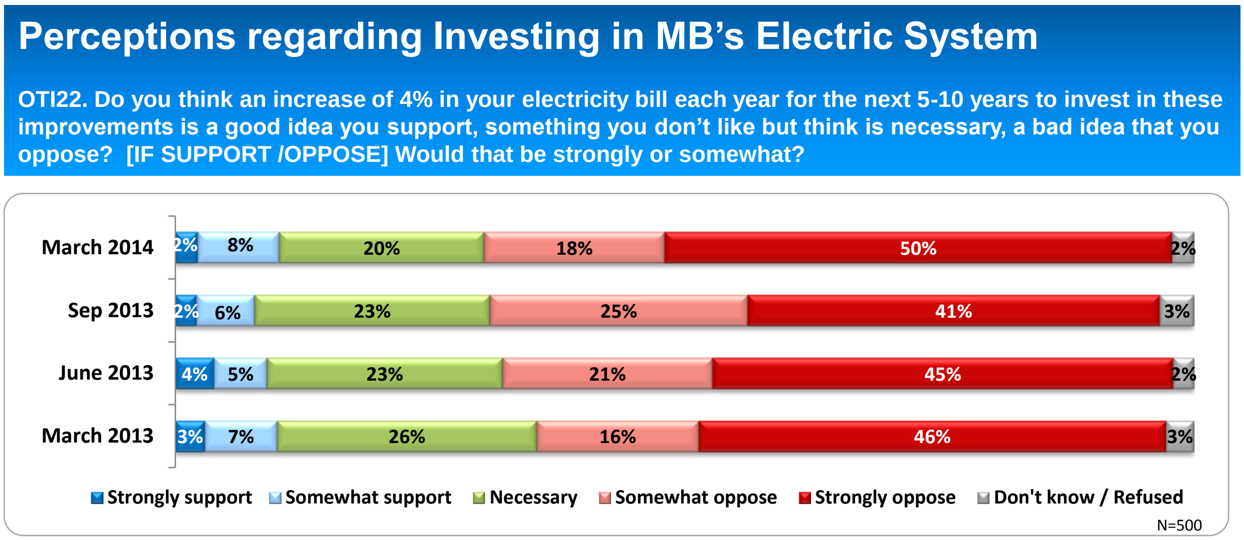
The majority of respondents (60%) supported or reluctantly supported increasing the price of electricity to invest in improvements to Manitoba's electricity system. This includes 17% who outright supported a price increase and 43% who reluctantly supported it. Over one-third (37%) of respondents opposed increasing the price of electricity to invest in improvements to Manitoba's electricity system.

Figure 5. Perceptions on Investing in Electric Infrastructure (2014 Survey)



Over half of respondents (59%) thought that some level of annual increase in their electricity bill for the next 5-10 years would be reasonable to upgrade Manitoba's aging electric system and add new generation capacity to meet Manitoban's growing electrical needs.

Figure 6. Perceptions on Investing in Electric Infrastructure (2014 Survey)



A third of respondents (30%) indicated they supported or reluctantly supported an increase of 4% in their electricity bill each year for the next 5-10 years to invest in these improvements to Manitoba's electricity system. This includes 10% who outright supported a 4% annual increase and 30% who reluctantly supported a 4% annual rate increase. 68% of respondents opposed such a rate increase.

c) Aside from the materials noted above, Manitoba Hydro has not prepared any other analyses and reports of the impact of the proposed rate increases on the Manitoba economy, Manitoba Hydro's customer classes/sub-classes, lower income customers, delinquent customers, or bad debt allowance.

REFERENCE:

Appendix 1 pg. 4; Appendix 3.1 pg 54 (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Refile the Projected Cash Flow Statement presented in Appendix 1, using the Direct Method with capitalized interest reclassified as investing activities for presentation purposes on a consistent basis with the presentation in Appendix 3.1 pg. 54 (2017/18 GRA).
b) Provide the rationale for classifying capitalized interest as an operating activity in the Cash Flow Statement as referenced in Note 3(s) of the 2017/18 Annual Report.
c) Provide a detailed breakdown of cash flow use for property plant and equipment by major project (in-service and Construction Work In Progress) for the years 2017/18, 2018/19 and 2019/20. Indicate the amount of capitalized interest in each of the years.
d) Provide a breakdown of the use of cash for additions to intangible assets for 2017/18, 2018/19, and 2019/20.

RESPONSE:

a) Please see the Projected Cash Flow below using the Direct Method with capitalized interest reclassified as investing activities.

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

For the year ended March 31	**ACTUAL 2018**	**OUTLOOK 2019**	**INTERIM BUDGET 2020**
OPERATING ACTIVITIES			
Cash Receipts from Customers	1 883	2 067	2 165
Cash Paid to Suppliers and Employees	(1 158)	(844)	(879)
Interest Paid	(538)	(689)	(750)
Interest Received	23	10	21
Cash Provided by Operating Activities	211	545	557
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt*	3 441	3 780	2 350
Retirement of Long-Term Debt	(583)	(1 000)	(346)
Repayments from/(Advances to) External Entities	(57)	(51)	(45)
Proceeds from Partnership Issuances	44	50	44
Sinking Fund Withdrawals	165	0	0
Sinking Fund Payment	(165)	(213)	(254)
Other	(11)	(0)	0
Cash Provided by Financing Activities	2 833	2 567	1 749
INVESTING ACTIVITIES			
Additions to Capital Assets	(2 949)	(2 735)	(1 810)
Additions to Intangible Assets	(135)	(239)	(223)
Additions to Regulatory Deferral Balances	(93)	(92)	(129)
Contributions Received	194	57	13
Cash Paid to the City	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(130)	(68)
Other	(3)	(0)	(0)
Cash Used for Investing Activities	(3 048)	(3 154)	(2 233)
Net Increase (Decrease) in Cash	(4)	(43)	73
Cash at Beginning of Year	634	574	530
Cash at End of Year	629	530	604

* 2018 Actuals include $3.4 billion related to proceeds from Long-Term Debt and $0.05 billion net proceeds from short-term borrowings (Notes Payable).

b) The decision to reclassify capitalized interest to operating activities from investing activities was to provide readers of the financial statements with the total interest paid by the corporation regardless of whether expensed or capitalized given the significance of the corporation's debt portfolio. The reclassification was accepted by Manitoba Hydro's external auditors in their review of the 2017/18 financial statements.

c) Please see the following table which provides a detailed breakdown of cash flow for property, plant and equipment by major project.

For the year ended March 31 ***(in millions of dollars)***	**ACTUAL 2018**	**OUTLOOK 2019**	**INTERIM BUDGET 2020**
KEEYASK			
Total Capital Spending	1 244	1 243	1 098
Capitalized Interest	151	199	253
BIPOLE III			
Total Capital Spending	1 137	800	23
Capitalized Interest	162	44	0
MMTP			
Total Capital Spending	28	160	142
Capitalized Interest	2	5	13
BIRTLE			
Total Capital Spending	2	2	20
Capitalized Interest	0	0	0

d) Portions of this response contain information considered to be confidential and commercially sensitive. The confidential portions have been highlighted, and those portions redacted in the public version of this response.

Please see the following table for a breakdown of cash used for additions to intangible assets.

INTANGIBLE ASSETS
(in millions of dollars)

GNTL	104	[redacted]		
Other Intangibles	33			3a
Capitalized Interest	3	14	25	
Total Capital Spending	137	239	223	

REFERENCE:

Appendix 1 pg. 4; Appendix 3.1 pg 54 (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Refile the Projected Cash Flow Statement presented in Appendix 1, using the Direct Method with capitalized interest reclassified as investing activities for presentation purposes on a consistent basis with the presentation in Appendix 3.1 pg. 54 (2017/18 GRA).
b) Provide the rationale for classifying capitalized interest as an operating activity in the Cash Flow Statement as referenced in Note 3(s) of the 2017/18 Annual Report.
c) Provide a detailed breakdown of cash flow use for property plant and equipment by major project (in-service and Construction Work In Progress) for the years 2017/18, 2018/19 and 2019/20. Indicate the amount of capitalized interest in each of the years.
d) Provide a breakdown of the use of cash for additions to intangible assets for 2017/18, 2018/19, and 2019/20.

RESPONSE:

a) Please see the Projected Cash Flow below using the Direct Method with capitalized interest reclassified as investing activities, updated to reflect the financial projections in Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019.

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

For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
OPERATING ACTIVITIES			
Cash Receipts from Customers	1 883	2 111	2 187
Cash Paid to Suppliers and Employees	(1 158)	(836)	(843)
Interest Paid	(538)	(690)	(717)
Interest Received	23	14	16
Cash Provided by Operating Activities	211	600	642
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt*	3 441	3 852	2 150
Retirement of Long-Term Debt	(583)	(1 775)	(227)
Repayments from/(Advances to) External Entities	(57)	(52)	(45)
Proceeds from Partnership Issuances	44	51	44
Sinking Fund Withdrawals	165	193	130
Sinking Fund Payment	(165)	(193)	(214)
Other	(11)	0	0
Cash Provided by Financing Activities	2 833	2 076	1 838
INVESTING ACTIVITIES			
Additions to Capital Assets	(2 949)	(2 193)	(2 021)
Additions to Intangible Assets	(135)	(231)	(231)
Additions to Regulatory Deferral Balances	(93)	(94)	(96)
Contributions Received	194	62	13
Cash Paid to the City	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(104)	(69)
Other	(3)	(1)	(0)
Cash Used for Investing Activities	(3 048)	(2 578)	(2 421)
Net Increase (Decrease) in Cash	(4)	98	59
Cash at Beginning of Year	634	579	678
Cash at End of Year	629	678	737

* 2018 Actuals include $3.4 billion related to proceeds from Long-Term Debt and $0.05 billion net proceeds from short-term borrowings (Notes Payable).

b) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

c) Please see the following table which provides a detailed breakdown of cash flow for property, plant and equipment by major project, based on the financial projections in Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019.

Table 1. Cash Flow Used for PP&E by MNG&T Project

For the year ended March 31 *(in millions of dollars)*	**ACTUAL 2018**	**CURRENT OUTLOOK 2019**	**APPROVED BUDGET 2020**
KEEYASK			
Total Capital Spending	1 244	1 282	1 113
Capitalized Interest	*151*	*200*	*253*
BIPOLE III			
Total Capital Spending	1 137	335	120
Capitalized Interest	*162*	*35*	*0*
MMTP			
Total Capital Spending	28	75	272
Capitalized Interest	*2*	*3*	*11*
BIRTLE			
Total Capital Spending	2	2	25
Capitalized Interest	*0*	*0*	*1*
Total Capital Spending (incl. capitalized interest)	**2 410**	**1 694**	**1 529**

d) Portions of this response contain information considered to be confidential and commercially sensitive. This response is being filed in confidence consistent with the PUB's ruling in its letter of February 5, 2019. The confidential portions have been highlighted, and those portions redacted in the public version of this response.

Please see the following table for a breakdown of cash used for additions to intangible assets, based on the financial projections in Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019. The 2017/18 figures below have been revised to reflect electric operations only.

Table 2. Cash Flow Used for Intangible Assets

For the year ended March 31 *(in millions of dollars)*	**ACTUAL 2018**	**CURRENT OUTLOOK 2019**	**APPROVED BUDGET 2020**	
GNTL	104	[redacted]	[redacted]	3a
Other Intangibles	29	[redacted]	[redacted]	
Capitalized Interest	3	13	23	
Total Intangible Spending (incl. capitalized interest)	**135**	**231**	**231**	

REFERENCE:

Application Fig 1.1; 2017/18 GRA MH-93

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide an update to Figure 1.1 detailing the specific components of the increases and decreases from MH-93 for 2017/18, 2018/19 and 2019/20.

RESPONSE:

The specific components of the increases and decreases from MH93, as summarized in Figure 1.1, were detailed in the following figures filed in the 2019/20 Electric Rate Application:

2017/18	Figure 2.2, page 9 of 43
2018/19	Figure 2.4, page 13 of 43
2019/20	Figure 2.5, page 19 of 43

REFERENCE:

Application Appendix 2, Appendix 3 pg.40

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has reported that it spent $2.924 billion in 2017/18 on investment in Property, Plant and Equipment including capitalized interest. In IFF16-1 Manitoba Hydro forecast to spend $3.6 billion in 2017/18.

QUESTION:

Provide details of and explain the underspend in capital projects of $676 million of the cash flow statement from that forecast in IFF16-Update for that year.

RESPONSE:

The $3.6 billion forecasted in the Projected Cash Flow Statement (Investment in Property, Plant & Equipment net of contributions) per IFF16-1 represents the forecasted cash based capital spend which includes spending on property, plant and equipment, intangible assets, deferred capital expenditures and mitigation and major development activities on a consolidated level (natural gas, electric and other segments). The $2.924 billion reported in the 2017/18 annual report is the accrual based capital expenditures for solely the Electric segment and in addition does not include intangible assets, deferred expenditures or mitigation items. When adjusting the IFF16 forecasted cash flow by removing the expenditures for the natural gas and other segments, intangible assets, mitigation and regulatory costs, DSM expenditures and adjustments for accruals, the forecasted 2017/18 capital spend is approximately $3.002 billion, slightly higher than the actual capital expenditures of $2.924 billion incurred. Please see the following table for a reconciliation of the IFF16 consolidated cash flow to the forecasted electric capital spending.

Reconciliation of IFF16 consolidated cash flow to forecasted electric capital spending	
Consolidated cash flow spending on PP&E per IFF16 Cash Flow	$ 3 600
Less: cash flow spending on PP&E by natural gas and other segments	(47)
Electric cash flow spending on PP&E per IFF16 Cash Flow	3 553
Remove:	
Deferred expenditures	(204)
Intangible expenditures	(8)
Mitigation expenditures	(12)
Regulatory expenditures	(7)
Demand side management expenditures	(56)
Adjust for:	
Accruals not included in cash flow	(264)
Forecasted electric Capex per IFF16	$ 3 002

REFERENCE:

Application Appendix 4 Segmented Information

PREAMBLE TO IR (IF ANY):

QUESTION:

a) File the detailed income statement and statement of cash flows by Quarter for Q1 actual electric operations, Q2 actual electric operations, and that forecast for Q3 and Q4.
b) File the Q3 quarterly report when available and provide detail of the income statement and statement of cash flows for the Quarter.
c) Provide a comparison of the forecast for Q3 with actual Q3 electric operations results for 2018/19 for both the income statement and statement of cash flow in the same level of detail as (b) and explain any difference from forecast, with comment on achievement of the annual forecast of net income for electric operations.

RESPONSE:

a) Please see the following income statement and statement of cash flows. These schedules include actual electric operations results for Q1 and Q2 of 2018/19 and reflect the 2018/19 Outlook included in Appendix 1 of the Application for Q3 and Q4.

ELECTRIC OPERATIONS
STATEMENT OF INCOME
QUARTERLY RESULTS FOR THE FISCAL YEAR ENDED MARCH 31, 2019
(in millions of dollars)

	Three Month Q1	Three Month Q2	Six Month Q3&4
Revenues			
Domestic revenue	$332	$360	$965
Extraprovincial	116	133	143
Other	8	22	57
	456	515	1 165
Expenses			
Operating and administrative	123	126	252
Net finance expense	145	195	368
Depreciation and amortization	101	120	252
Water rentals and assessments	27	27	59
Fuel and power purchased	26	33	79
Capital and other taxes	36	35	71
Other expenses	21	25	32
Corporate allocations	2	2	4
	481	564	1 118
Net income (loss) before net movement in regulatory balanc	(24)	(48)	48
Net movement in regulatory balances	17	21	31
Net Income (Loss)	**($ 7)**	**($ 27)**	**$ 78**
Net income (loss) attributable to:			
Manitoba Hydro	**($ 5)**	**($ 27)**	**$ 83**
Non-controlling interests	(2)	(0)	(4)
	($ 7)	**($ 27)**	**$ 78**

ELECTRIC OPERATIONS
CASH FLOW STATEMENT - INDIRECT
QUARTERLY RESULTS FOR THE FISCAL YEAR ENDED MARCH 31, 2019
(in millions of dollars)

	Three Month Q1	Three Month Q2	Six Month Q3&4
Operating Activities			
Net income (loss)	($7)	($27)	$78
Add back:			
Depreciation and amortization	101	120	252
Net finance expense	145	195	368
Net movement impacts on depreciation, amortization and finance expense	6	7	10
Adjustments for non-cash items	(2)	(21)	38
Adjustments for changes in non-cash working capital accounts	(92)	(6)	58
Interest received	8	8	(5)
Interest paid	(299)	(273)	(402)
Cash (used for) provided by operating activities	(139)	1	397
Investing Activities			
Additions to property, plant and equipment	(487)	(457)	(1 521)
Additions to intangible assets	(55)	(19)	(150)
Additions to regulatory deferral balances	(23)	(29)	(38)
Contributions received	62	15	(20)
Cash paid to the City of Winnipeg	-	(16)	-
Cash paid for mitigation and major development activities	(7)	(6)	(117)
Other	(5)	2	3
Cash used for investing activities	(516)	(510)	(1 843)
Financing Activities			
Proceeds from short and long-term debt	1 686	990	1 104
Retirement of short and long-term debt	(851)	(528)	380
Advances to external parties and related parties	(21)	(37)	7
Proceeds from partnership issuances	14	14	23
Sinking fund payments	-	-	(213)
Cash provided by financing activities	827	439	1 300
Net increase (decrease) in cash and cash equivalents	172	(70)	(146)
Cash and cash equivalents, beginning of year	629	801	731
Cash and cash equivalents, end of period	**801**	**731**	**585**

b) Manitoba Hydro will file its Q3 quarterly report after the results have been released publicly, as well as details of the income statement and statement of cash flows for the quarter.

c) Manitoba Hydro will provide a comparison of the forecast for Q3 with actual Q3 electric operations results for 2018/19, as well as an explanation of differences between actual and forecast once the Q3 results have been released publicly.

REFERENCE:

Application Appendix 4 Segmented Information

PREAMBLE TO IR (IF ANY):

QUESTION:

b) File the Q3 quarterly report when available and provide detail of the income statement and statement of cash flows for the Quarter.

RESPONSE:

Please see the attached quarterly report. The following schedules provide the details of the income statement and statement of cash flows, including actual electric operations results for Q1, Q2 and Q3 of 2018/19 and the 2018/19 Current Outlook filed as part of the Supplement to the Application filed on February 14, 2019 for Q4.

ELECTRIC OPERATIONS
STATEMENT OF INCOME
QUARTERLY RESULTS FOR THE FISCAL YEAR ENDED MARCH 31, 2019
(in millions of dollars)

	Three Month Q1	Three Month Q2	Three Month Q3	Projected Three Month Q4	Current Outlook 2019
Revenues					
Domestic revenue	$332	$360	$451	$515	$1 659
Extraprovincial	116	133	101	82	432
Other	8	22	27	27	85
	456	515	580	623	2 175
Expenses					
Operating and administrative	123	126	128	123	501
Net finance expense	145	195	188	184	712
Depreciation and amortization	101	120	121	123	465
Water rentals and assessments	27	27	28	32	114
Fuel and power purchased	26	33	38	38	135
Capital and other taxes	36	35	35	33	140
Other expenses	21	25	19	14	79
Corporate allocations	2	2	2	2	8
	481	564	559	550	2 154
Net income (loss) before net movement in regulatory balances	(24)	(48)	21	74	22
Net movement in regulatory balances	17	21	16	16	70
Net Income (Loss)	**($ 7)**	**($ 27)**	**$ 37**	**$ 90**	**$ 92**
Net income (loss) attributable to:					
Manitoba Hydro	**($ 5)**	**($ 27)**	**$ 38**	**$ 90**	**$ 95**
Non-controlling interests	(2)	(0)	(1)	(0)	(3)
	($ 7)	**($ 27)**	**$ 37**	**$ 90**	**$ 92**

ELECTRIC OPERATIONS
CASH FLOW STATEMENT - INDIRECT
QUARTERLY RESULTS FOR THE FISCAL YEAR ENDED MARCH 31, 2019
(in millions of dollars)

	Three Month Q1	Three Month Q2	Three Month Q3	Projected Three Month Q4	Current Outlook
Operating Activities					
Net income (loss)	($7)	($27)	$37	$90	$92
Add back:					
Depreciation and amortization	101	120	121	123	465
Net finance expense	145	195	188	184	712
Net movement impacts on depreciation, amortization and finance expense	6	7	5	3	21
Adjustments for non-cash items	(2)	(21)	(20)	60	17
Adjustments for changes in non-cash working capital accounts	(92)	(6)	(52)	118	(32)
Interest received	8	8	8	(9)	14
Interest paid	(299)	(273)	(115)	(277)	(964)
Cash (used for) provided by operating activities	(139)	1	171	293	326
Investing Activities					
Additions to property, plant and equipment	(487)	(457)	(457)	(532)	(1 933)
Additions to intangible assets	(55)	(19)	(56)	(88)	(219)
Additions to regulatory deferral balances	(23)	(29)	(22)	(19)	(93)
Contributions received	62	15	8	(23)	62
Cash paid to the City of Winnipeg	-	(16)	-	-	(16)
Cash paid for mitigation and major development activities	(7)	(6)	(7)	(84)	(104)
Other	(5)	2	(1)	4	(1)
Cash used for investing activities	(516)	(510)	(535)	(742)	(2 303)
Financing Activities					
Proceeds from short and long-term debt	1 686	990	216	960	3 852
Retirement of short and long-term debt	(851)	(528)	(242)	(154)	(1 775)
Advances to external parties and related parties	(21)	(37)	(22)	28	(52)
Proceeds from partnership issuances	14	14	13	11	51
Sinking fund payments	-	-	-	-	-
Cash provided by financing activities	827	439	(35)	845	2 076
Net increase (decrease) in cash and cash equivalents	172	(70)	(399)	396	98
Cash and cash equivalents, beginning of year	629	801	731	332	579
Cash and cash equivalents, end of period	**801**	**731**	**332**	**727**	**678**

The Manitoba Hydro-Electric Board

Quarterly Report

for the nine months ended
December 31, 2018

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

Financial Overview

Manitoba Hydro's consolidated net loss was $1 million for the first nine months of the 2018-19 fiscal year compared to a net loss of $47 million for the same period last year. The decrease in the net loss is primarily attributable to lower restructuring costs when compared to restructuring costs incurred for a significant cost reduction program in the prior year. Excluding restructuring expenses, Manitoba Hydro would have reported net income of $3 million compared to a net loss of $2 million in the prior year. The $5 million improvement is mostly attributable to weather and rate impacts resulting in an increase in domestic electric revenue, an increase in other revenue due to the recognition of the Bipole III reserve into income as well as a decrease in operating and administrative expenses associated with savings from the Voluntary Departure Program (VDP). These improvements were partially offset by an increase in net financing costs associated with higher interest on debt as well as higher depreciation and amortization expense as new assets were placed in-service. The cost of natural gas is a flow through cost passed onto customers through rates approved by the Public Utilities Board (PUB) and therefore is not a driver for the decrease in net loss compared to the prior year.

The consolidated net loss was comprised of a $5 million net profit in the electricity segment, a $12 million loss in the natural gas segment, a $4 million net profit in the other segment and a $2 million profit impact in adjustments and eliminations. The loss in the natural gas segment is the result of seasonal variations in the demand for natural gas and is expected to be recouped over the winter heating season.

Manitoba Hydro's budgeted net income for 2018-19 is $136 million; however Manitoba Hydro is currently projecting net income to be approximately $100 million. The lower expected net income factors in the impact of the PUB's decision to grant a 3.6% rate increase rather than the requested 7.9% rate increase partially offset by favourable weather impacts throughout the first nine months. The projection for the remainder of the year assumes average water flow conditions and normal winter weather.

Electric Segment

Revenues from electricity sales within Manitoba totaled $1 144 million for the nine-month period, which was $122 million or 12% higher than the same period last year. The increase in domestic revenue was primarily attributable to the impacts of weather and revenues previously deferred in the Bipole III deferral account which are now recognized as revenue compared to the prior year. Extraprovincial revenues of $350 million were $16 million or 4% lower than the same period last year reflecting lower U.S. opportunity and dependable sales volumes primarily as a result of lower generation due to less favourable water conditions compared to 2017-18, partially offset by modestly higher export prices. Overall, energy sold in the export market was 5.2 billion kilowatt-hours compared to 8.5 billion kilowatt-hours sold in the same period last year. Other revenues of $58 million were $39 million or 205% higher than the same period last year due to the amortization of the Bipole III reserve into income.

Expenses attributable to electricity operations, including the net movement in regulatory deferral balances, totaled $1 549 million for the nine-month period. This represented an increase of $97 million or 7% as compared to the same period last year. Excluding restructuring charges, expenses increased $136 million over the prior year. The increase was primarily due to an $86 million increase in net finance expense due to interest associated with Bipole III and higher debt volumes and a $46 million increase in depreciation largely due to Bipole III going into service at the beginning of July. There was also an increase in fuel and power purchase costs as a result of a one-time $9 million write off of coal inventory as the Brandon Thermal Generating Station is no longer operational as a coal powered generator. Amortization of regulatory deferrals increased $14 million due to amortization of the Conawapa deferral and ineligible overhead as per direction from the PUB. This was partially offset by a decrease of $11 million in operating and administrative expenses due to a reduction in employee related expenditures as a result of the VDP and a $13 million decrease in water rentals and assessments due to lower hydraulic generation.

The net loss before net movement in regulatory balances was $52 million. The net movement in regulatory balances captures the timing differences of revenues and expenses for financial reporting purposes and those amounts approved by the PUB for rate-setting purposes. After considering the net movement of $54 million in the regulatory deferral balances, there is a net income of $2 million, of which $5 million is attributable to Manitoba Hydro and $3 million net loss is attributable to non-controlling interest. The non-controlling interest represents Taskinigahp Power Corporation's 33% share of the Wuskwatim Power Limited Partnership's operating results for the first nine months of the 2018-19 fiscal year.

Expenditures for capital construction for the nine-month period amounted to $1 584 million compared to $2 136 million for the same period last year. Expenditures for the current period included $1 021 million related to construction of the Keeyask Project and $178 million for the Bipole III Reliability Project. The remaining capital expenditures were predominantly incurred for ongoing system additions and modifications necessary to meet the electrical service requirements of customers throughout the province. The corporation also incurred $53 million for electric demand side management programs.

Natural Gas Segment

The net loss in the natural gas segment was $12 million for the nine-month period compared to a $17 million net loss for the same period last year. The lower net loss is primarily due to increased gross margin due to weather impacts, lower restructuring costs and lower operating and administrative expenses as a result of the VDP. Delivered gas volumes were 1 347 million cubic metres compared to 1 218 million cubic metres for the same period last year.

Expenses attributable to natural gas operations excluding cost of gas sold amounted to $111 million compared to $114 million for the same period last year. The decrease in expenses is primarily attributable to lower current year employee related expenditures as a result of the VDP and higher restructuring charges in the prior year.

The net loss before net movement in regulatory balances is $20 million. After considering the net movement of $8 million in the regulatory balances, there is a net loss of $12 million.

Capital expenditures in the natural gas segment were $30 million for the current nine-month period compared to $27 million for the same period last year. Capital expenditures are related to system improvements and other expenditures necessary to meet the natural gas service requirements of customers throughout the province. The corporation also incurred $8 million for gas demand side management programs.

Other Segment

The other segment includes Manitoba Hydro International Ltd., Manitoba Hydro Utility Services, Minell Pipelines Ltd. and Teshmont Holdings Ltd. The net income was $4 million in the other segment for the nine-month period compared to net income of $5 million in the same period last year. Revenue was $42 million compared to $47 million for the same period last year. Expenses attributable to the other segment amounted to $38 million which was $4 million lower than the prior year. The decrease in both revenue and expenses is primarily due to fewer projects undertaken at Manitoba Hydro International Ltd. compared to the prior year.

There is also a $2 million profit impact in adjustments and eliminations as a result of the requirement to harmonize accounting policies between electric and natural gas operations related to the gas meter exchange program.

Keeyask Project Completes 2018 Milestones

Located approximately 725 kilometres north of Winnipeg on the lower Nelson River, the Keeyask Project is a 695-megawatt hydroelectric generating station being developed in a partnership between Manitoba Hydro and four Keeyask Cree Nation (KCN) communities: Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation.

With the 2018 construction season wrapped up, the Keeyask Project achieved all of its 2018 goals, and even exceeded some targets. Work completed included the Spillway and river diversion; placement of more than 113 000 cubic meters (m^3) of concrete, exceeding the goal of 105 000 m^3; opening of the South Access Road to construction traffic; placement of 3.6 million m^3 of earth material (equivalent to 180 000 truckloads); and the installation of the planned embedded turbine and generator components on Units 1, 2 and 3 and enclosure of Units 4 and 5.

With progress to date, the anticipated in-service date for the first unit is October 2020. With the advances in the construction schedule at end of December 2018, the project is currently tracking towards meeting the established $8.7 billion project control budget. Three years of work remain on the project.

Manitoba Hydro to Sell 215 MW of Renewable Hydroelectricity to SaskPower

October 29, 2018, Manitoba Hydro announced a term sheet had been signed between Manitoba Hydro and SaskPower which will see up to 215 megawatts of renewable hydroelectricity flow from Manitoba to Saskatchewan beginning in 2022.

The sale will last a minimum of 18 years with a potential extension up to a total of 30 years, bringing long-term benefits to electricity customers in both provinces. The sale is the largest of three recent major power deals between the two provinces. By 2022, Manitoba Hydro will be supplying up to 315 megawatts of hydroelectricity to Saskatchewan.

Revenues from the sale will assist in keeping electricity rates affordable for Manitoba customers, and help SaskPower expand and diversify its renewable energy supply. SaskPower's goal is to reduce greenhouse gas emissions by 40% by 2030.

The sale to SaskPower will utilize capacity provided by a new 230 000 volt transmission line planned for construction between Birtle, Manitoba and Tantallon, Saskatchewan. When complete, the 80 kilometre line, announced in 2015, will also improve the reliability of the electrical grid, benefiting customers in both provinces. The line is anticipated to be in service in 2021.

Upgrading Aging Infrastructure in Winnipeg

In November 2018, Manitoba Hydro began a year-long project to upgrade electrical service to customers in the Glenwood area of south-east Winnipeg. The project involves upgrading power lines originating out of Dunraven Station, located at 25 Dunraven Ave., from 4 000 volts to 24 000 volts. Many critical components of the infrastructure in the area are more than 60 years old and reaching the end of their life span. In addition to this work, about 250 old wood poles in the area will also be replaced to ensure the continued safe ground clearance and mechanical support of power lines and energized equipment. This work is part of the utility's infrastructure renewal projects throughout the province to ensure the reliability and security of electrical service to Manitobans.

Outside of Winnipeg, Manitoba Hydro is improving the reliability of service and enhancing the capacity of its system. In many cases, renewal projects involve upgrading distribution stations and power lines originally built during the Farm Electrification Program that followed World War II.

Manitoba Hydro's $10 Instant Rebate for Approved Carbon Monoxide Alarms

During the month of November 2018, Manitoba Hydro offered a $10 rebate on carbon monoxide alarms through 100 participating retailers throughout the province. The rebate, applied immediately at time of purchase, saw 4 381 units sold. The beginning of the rebate program coincided with National Carbon Monoxide Awareness Week, aimed at telling homeowners and businesses about carbon monoxide (CO) exposure and safety.

The goal of the rebate program, supported by Manitoba's Office of the Fire Commissioner and the Winnipeg Fire and Paramedic Service, was to get more Manitobans to install CO alarms in their homes and businesses, and to replace CO alarms older than 10 years. Safety materials included information on proper use and maintenance of your natural gas furnace and other fuel-burning appliances.

Participating retailers in Manitoba Hydro's rebate program were: Canadian Tire (15 locations); Costco (three locations); EG Penner Building Centres Ltd. (Steinbach); Grunthal Lumber; Home Depot (six locations); Home Hardware (45 locations); London Drugs (1225 St. Mary Rd.); McMunn & Yates (15 locations); Rona (12 locations); and WM Dyck & Sons (Niverville).

Marina R. James

Chair of the Board

Jay Grewal

President and
Chief Executive Officer

February 14, 2019

Consolidated Statement of Income

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		Three Months Ended December 31	
	2018	**2017**	**2018**	**2017**
Revenues				
Domestic – Electric	1 144	1 022	452	393
– Gas	210	202	118	114
Extraprovincial	350	366	101	91
Other	95	60	41	21
	1 799	1 650	712	619
Expenses				
Cost of gas sold	121	116	75	63
Operating and administrative	431	444	147	141
Finance expense (net)	556	471	197	147
Depreciation and amortization	363	316	128	106
Water rentals and assessments	82	95	28	31
Fuel and power purchased	97	93	38	36
Capital and other taxes	120	111	40	37
Other expenses	95	135	30	36
	1 865	1 781	683	597
Net loss before net movement in regulatory balances	(66)	(131)	29	22
Net movement in regulatory balances	62	76	21	23
Net Income (Loss)	(4)	(55)	50	45
Net income (loss) attributable to:				
Manitoba Hydro	(1)	(47)	51	46
Non-controlling interest	(3)	(8)	(1)	(1)
	(4)	(55)	50	45

Consolidated Statement of Financial Position

In Millions of Dollars (Unaudited)

	As at December 31	As at March 31	As at December 31
	2018	**2018**	**2017**
Assets			
Current assets	915	1 221	1 235
Property, plant and equipment	23 291	21 979	21 673
Non-current assets	1 100	925	854
Total assets before regulatory deferral balance	25 306	24 125	23 762
Regulatory deferral balance	1 100	1 044	635
	26 406	25 169	24 397
Liabilities and Equity			
Current liabilities	847	2 080	2 247
Long-term debt	20 560	18 200	17 285
Other long-term liabilities	1 627	1 591	1 571
Deferred revenue	864	769	776
Non-controlling interest	243	205	193
Retained earnings	2 935	2 936	2 852
Accumulated other comprehensive loss	(740)	(688)	(597)
Total liabilities and equity before regulatory deferral balance	26 336	25 093	24 327
Regulatory deferral balance	70	76	70
	26 406	25 169	24 397

Consolidated Cash Flow Statement

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		*Three Months Ended December 31*	
	2018	**2017**	**2018**	**2017**
Operating Activities	55	(153)	181	84
Investing Activities	(1 609)	(2 017)	(553)	(666)
Financing Activities	1 258	2 189	(30)	633
Net increase (decrease) in cash	(296)	19	(402)	51
Cash at beginning of period	642	646	748	614
Cash at end of period	346	665	346	665

Consolidated Statement of Comprehensive Income (Loss)

In Millions of Dollars (Unaudited)

	Nine Months Ended December 31		*Three Months Ended December 31*	
	2018	**2017**	**2018**	**2017**
Net Income (Loss) attributable to Manitoba Hydro	(1)	(47)	51	46
Other Comprehensive Income (Loss)				
Items that will be reclassified to income				
Unrealized foreign exchange gains (losses) on debt in cash flow hedges	(73)	95	(67)	(9)
Items that have been reclassified to income				
Realized foreign exchange losses on debt in cash flow hedges	21	17	7	4
	(52)	112	(60)	(5)
Comprehensive Income (Loss) attributable to Manitoba Hydro	(53)	65	(9)	41

Segmented Information

In Millions of Dollars (Unaudited)

Nine Months Ended December 31	Electric segment 2018	Electric segment 2017	Natural gas segment 2018	Natural gas segment 2017	Other segment 2018	Other segment 2017	Eliminations 2018	Eliminations 2017	Total 2018	Total 2017
Revenue	1 551	1 407	212	203	42	47	(6)	(7)	1 799	1 650
Expenses	1 603	1 518	232	230	38	42	(8)	(9)	1 865	1 781
Net income (loss) before net movement in regulatory balances	(52)	(111)	(20)	(27)	4	5	2	2	(66)	(131)
Net movement in regulatory balances	54	66	8	10	-	-	-	-	62	76
Net Income (Loss)	2	(45)	(12)	(17)	4	5	2	2	(4)	(55)
Net income (loss) attribute to:										
Manitoba Hydro	5	(37)	(12)	(17)	4	5	2	2	(1)	(47)
Non-controlling interest	(3)	(8)	-	-	-	-	-	-	(3)	(8)
	2	(45)	(12)	(17)	4	5	2	2	(4)	(55)

Three Months Ended December 31	Electric segment 2018	Electric segment 2017	Natural gas segment 2018	Natural gas segment 2017	Other segment 2018	Other segment 2017	Eliminations 2018	Eliminations 2017	Total 2018	Total 2017
Revenue	579	491	119	114	15	17	(1)	(3)	712	619
Expenses	559	485	113	102	13	14	(2)	(4)	683	597
Net income before net movement in regulatory balances	20	6	6	12	2	3	1	1	29	22
Net movement in regulatory balances	16	26	5	(3)	-	-	-	-	21	23
Net Income	36	32	11	9	2	3	1	1	50	45
Net income (loss) attribute to:										
Manitoba Hydro	37	33	11	9	2	3	1	1	51	46
Non-controlling interest	(1)	(1)	-	-	-	-	-	-	(1)	(1)
	36	32	11	9	2	3	1	1	50	45
Total assets	25 786	23 802	770	756	101	95	(251)	(256)	26 406	24 397

Generation and Delivery Statistics

	Nine Months Ended December 31 2018	2017	*Three Months Ended December 31* 2018	2017
Electricity in gigawatt-hours				
Hydraulic generation	22 569	26 302	7 642	8 376
Thermal generation	8	37	3	26
Scheduled energy imports	471	108	386	73
Wind purchases (Manitoba)	622	729	229	301
Total system supply	23 670	27 176	8 260	8 776
Gas in millions of cubic metres				
Gas sales	804	747	504	484
Gas transportation	543	471	204	204
	1 347	1 218	708	688

The Manitoba Hydro-Electric Board

Quarterly Report

for the nine months ended
December 31, 2018

For further information contact:

Manitoba Hydro
Public Affairs
360 Portage Ave. (2)
Winnipeg, Manitoba, Canada
R3C 0G8
Telephone: 1-204-360-3233

Manitoba Hydro

Available in accessible formats upon request.

REFERENCE:

Application Appendix 4 Segmented Information

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Provide a comparison of the forecast for Q3 with actual Q3 electric operations results for 2018/19 for both the income statement and statement of cash flow in the same level of detail as (b) and explain any difference from forecast, with comment on achievement of the annual forecast of net income for electric operations.

RESPONSE:

The following table provides a comparison of Manitoba Hydro's actual net income to December 31, 2018 budget for Electric operations. The budget information referenced below is the Approved Budget for 2018/19 as approved by the MHEB on March 16, 2018 and subsequently adjusted for the PUB directives in Order 59/18 including the 3.6% June 1, 2018 rate increase and accounting changes. In the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019, Manitoba Hydro projects net income for 2018/19 for Electric operations of $95 million. Manitoba Hydro does not prepare quarterly cash flow budgets; quarterly comparisons on the Statement of Cash Flow are done on a year over year basis.

MANITOBA HYDRO
ELECTRIC OPERATIONS
STATEMENT OF INCOME
For the Nine Month Period Ended December 31, 2018
(In Millions of Dollars)

	ACTUAL	BUDGET	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1 188	$1 163	$ 25
BPIII Reserve Account	(6)	(18)	12
Extraprovincial	350	341	9
Other	20	23	(3)
	1 552	1 509	43
Expenses			
Operating and administrative	378	376	(2)
Net finance expense	528	502	(26)
Depreciation and amortization	342	342	-
Water rentals and assessments	82	89	7
Fuel and power purchased	97	92	(5)
Capital and other taxes	107	107	-
Other expenses	64	53	(11)
Corporate allocation	6	6	-
	1 604	1 567	(37)
Net loss before net movement in regulatory balances	(52)	(58)	6
Net movement in regulatory balances	54	46	8
Net Income (Loss)	**$2**	**($12)**	**$14**
Net Income (Loss) attributable to:			
Manitoba Hydro	**$5**	**($7)**	**$12**
Non-controlling interests	(3)	(5)	2
	$2	**($12)**	**$14**

Domestic revenue was higher than planned primarily as a result of a warmer than normal summer and a cooler than normal spring and fall.

The Bipole III Reserve is higher than budget as a result of the early in-service date (less revenue deferred and earlier amortization of the reserve).

Extraprovincial revenue is higher than budget mainly as a result of higher prices impacting dependable revenues and foreign exchange impacts.

Other revenue is lower than budget due to an accounting standard change requiring reclassification of components of external billable overhead to deferred revenue.

Net finance expense is higher than budget primarily as a result of:

- higher net interest on debt mainly due to Bipole III going into service earlier than planned;
- foreign exchange losses on both US interest payments and cash flow hedges; partially offset by
- higher finance income as a result of higher volumes of temporary investments.

Water rentals and assessments are lower than budget as a result of lower generation.

Fuel & power purchased is higher than budget primarily as a result of the write-off of the coal inventory for the Brandon generating station. This is partially offset by lower transmission charges resulting from redirecting to lower cost nodes and lower wind purchases.

Other expenses are higher than budget primarily as a result of higher spending on Demand Side Management (“DSM”) programs. Note these expenses are offset through net movement and have no impact on net income.

Net movement in regulatory balances is higher than budget primarily as a result of higher DSM expenditures.

REFERENCE:

2017/18 GRA PUB MFR 18 and PUB/MH I-33

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide charts and respective data tables for each of the financial ratios for electric operations for 2017/18, 2018/19 and 2019/20.
b) Provide details of the determination of each of the financial ratios for electric operations for 2017/18, 2018/19 and 2019/20. Include the detail to allow for a reconciliation of the determination of each financial target with the same level of detail as PUB/MH I-33.
c) Provide a schedule in the format of PUB MFR 51 that indicates the amount of cash flow from electric operations (excluding capitalized interest in the calculation thereof), forecast electric base capital spending, and net cash flow available to finance each Major Generation & Transmission Project in 2017/18 through the test year. Include the (electric) capital coverage ratio consistent with the determination of the ratio in prior years.

RESPONSE:

Please see the response to a) and b) below.

Figure 1. Debt Ratio Calculation

Debt Ratio
Manitoba Hydro (Electric Only)
($ millions)

	A	B	C	D	E	F	G	H	(E-F+G-H) / (A+B+C+D+E-F+G-H)
Fiscal Year Ended	Retained Earnings	Unamortized Customer Contributions*	Accumulated Other Comprehensive Income	Non-Controlling Interest	Long-Term Debt	Sinking Fund Investment	Short-Term Debt	Short-Term Investments	Debt Ratio
2018	2 767	797	(688)	205	18 830	-	50	629	0.86
2019	2 818	805	(613)	251	21 722	213	-	530	0.87
2020	2 850	732	(586)	297	23 718	466	-	604	0.87

*2017/18 includes current portion of deferred revenue and a $29M FMV adjustment related to the acquisition of Centra Gas.

References in Projected Financial Statements:
Col A: Figure 5, Electric Operations Projected Balance Sheet, Retained Earnings
Col B: Figure 5, Electric Operations Projected Balance Sheet, Deferred Revenue plus Bipole III Reserve Account
Col C: Figure 5, Electric Operations Projected Balance Sheet, Accumulated Other Comprehensive Income
Col D: Figure 5, Electric Operations Projected Balance Sheet, Non-Controlling Interests
Col E: Figure 2, Column C
Col F: Figure 5, Electric Operations Projected Balance Sheet, Sinking Fund Investments
Col G: Figure 5, Electric Operations Projected Balance Sheet, Short-Term Debt
Col H: Figure 5, Electric Operations Projected Balance Sheet, Cash and Cash Equivalents

Figure 2. Long-Term Debt Calculation

Calculation of Long-Term Debt
for input into Debt:Equity Ratio
($ millions)

	A	B	C (A+B)
Fiscal Year Ended	Long-Term Debt	Current Portion of Long-Term Debt	Long-Term Debt
2018	17,830	1,000	18,830
2019	21,396	326	21,722
2020	22,430	1,288	23,718

*Long-Term Debt includes a $17M FMV adjustment for Centra Gas acquisition.

References in Projected Financial Statements:
Col A: Figure 5, Electric Operations Projected Balance Sheet, Long-Term Debt
Col B: Figure 5, Electric Operations Projected Balance Sheet, Current Portion of Long-Term Debt

Figure 3. EBITDA Interest Coverage Ratio Calculation

EBITDA Interest Coverage
Electric
($ millions)

	A	B	C	D	(A+B+C+D)/(B+C)
Fiscal Year Ended	Electric Net Income	Electric Finance Expense (net)	Electric Capitalized Interest	Electric Depreciation Expense	Electric EBITDA Interest Coverage
2018	18	584	342	407	1.46
2019	51	715	285	497	1.55
2020	31	771	315	535	1.52

References in Projected Financial Statements:

Col A: Figure 5, Electric Operations Projected Operating Statement, Net Income Attributable to Manitoba Hydro

Col B: Figure 5, Electric Operations Projected Operating Statement, Finance Expense less Finance Income plus Finance Expense Corporate Allocation

Col C: Figure 5, Electric Operations Projected Operating Statement, Capitalized Interest

Col D: Figure 5, Electric Operations Projected Operating Statement, Depreciation and Amortization plus Depreciation Corporate Allocation minus Depreciation & Amortization in Net Movement

Figure 4. Capital Coverage Ratio Calculation

Capital Coverage Ratio
Excluding Major Generation
Electric
($ millions)

	A	B	C (A+B)	D	E (C/D)
Fiscal Year Ended	Electric Funds from Operations	Electric Capitalized Interest	Electric Internally Generated Funds	Electric Capital Expenditures	Electric Capital Coverage
2018	(132)	342	210	461	0.46
2019	260	285	545	515	1.06
2020	242	315	557	511	1.09

References in Projected Financial Statements:

Col A: Figure 5, Electric Operations Projected Cash Flow Statement, Cash Flow from Operating Activities

Col B: Figure 5, Electric Operations Projected Operating Statement, Capitalized Interest

Col D: Appendix 6, Capital Expenditure Forecast (CEF18), page 12: Electric Business Operations Capital Total

Figure 5. Projected Financial Statements

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

		ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
	For the year ended March 31			
	REVENUES			
	Domestic Revenue			
	at approved rates	1 616	1 701	1 678
	additional	0	0	59
	BPIII Reserve Account	(152)	14	78
	Extraprovincial	437	392	411
	Other	30	30	29
		1 931	2 137	2 255
	EXPENSES			
	Operating and Administrative	517	501	511
	Gross Finance Expense	*943*	*1 018*	*1 114*
Figure 3 Column C	*Capitalized Interest*	*(342)*	*(285)*	*(315)*
Figure 3 Column B	Finance Expense	601	733	799
Figure 3 Column B	Finance Income	(23)	(25)	(34)
Figure 3 Column D	Depreciation and Amortization	402	473	508
	Water Rentals and Assessments	126	113	111
	Fuel and Power Purchased	130	138	160
	Capital and Other Taxes	130	142	150
	Other Expenses	501	78	111
Figure 3 Column B	*Finance Expense*	*6*	*6*	*6*
Figure 3 Column D	*Depreciation and Amortization*	*1*	*1*	*1*
	Other Revenues	*0*	*0*	*0*
	Corporate Allocation	8	8	8
		2 393	2 161	2 325
	Net Income before Net Movement in Reg. Deferral	(462)	(24)	(70)
	Operating and Administrative	*20*	*20*	*20*
Figure 3 Column D	*Depreciation and Amortization*	*(3)*	*(23)*	*(26)*
	Other Expenses	*454*	*71*	*108*
	Net Movement in Regulatory Deferral	472	69	103
	Net Income	10	45	33
	Net Income Attributable to:			
Figure 3 Column A	**Manitoba Hydro**	**18**	**51**	**31**
	Non-controlling Interest	(8)	(6)	2
		10	45	33
	PUB Approved Percent Increase	3.36%	3.60%	-
	Proposed Percent Increase	-	-	3.50%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
(In Millions of Dollars)

		For the year ended March 31	**ACTUAL 2018**	**OUTLOOK 2019**	**INTERIM BUDGET 2020**
		ASSETS			
		Plant in Service	13 681	19 106	19 645
		Accumulated Depreciation	(1 302)	(1 774)	(2 233)
		Net Plant in Service	12 380	17 332	17 412
		Construction in Progress	8 995	6 322	7 511
Figure 1	Column H	*Cash and Cash Equivalents*	*629*	*530*	*604*
		Other Current Assets	*510*	*425*	*527*
Figure 1	Column F	*Sinking Fund Investments*	*0*	*213*	*466*
		Other Non-Current Assets	*653*	*721*	*792*
		Current and Other Assets	1 792	1 890	2 388
		Goodwill and Intangible Assets	440	693	895
		Total Assets before Regulatory Deferral	23 607	26 237	28 206
		Regulatory Deferral Balance	933	948	1 050
			24 540	27 184	29 256
		LIABILITIES AND EQUITY			
Figure 2	Column A	Long-Term Debt	17 813	21 396	22 430
Figure 2	Column B	*Current Portion of Long-Term Debt*	*1 000*	*326*	*1 288*
Figure 1	Column G	*Short-Term Debt*	*50*	*0*	*0*
		Other Current Liabilities	*1 008*	*592*	*613*
Figure 1	Column D	*Non-Controlling Interests*	*205*	*251*	*297*
		Other Non-Current Liabilities	*1 515*	*1 561*	*1 586*
		Current and Other Liabilities	3 777	2 729	3 784
		Provisions	60	49	47
Figure 1	Column B	Deferred Revenue	414	472	478
Figure 1	Column B	BPIII Reserve Account	348	333	255
Figure 1	Column A	Retained Earnings	2 767	2 818	2 850
Figure 1	Column C	Accumulated Other Comprehensive Income	(688)	(613)	(586)
		Total Liabilities and Equity before Regulatory Deferral	24 491	27 184	29 256
		Regulatory Deferral Balance	49	0	0
			24 540	27 184	29 256

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

	For the year ended March 31	ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
	OPERATING ACTIVITIES			
	Cash Receipts from Customers	1 883	2 067	2 165
	Cash Paid to Suppliers and Employees	(1 158)	(844)	(879)
	Interest Paid	(880)	(974)	(1 065)
	Interest Received	23	10	21
Figure 4 Column A	**Cash Provided by Operating Activities**	(132)	260	242
	FINANCING ACTIVITIES			
	Proceeds from Long-Term Debt	3 441	3 780	2 350
	Retirement of Long-Term Debt	(583)	(1 000)	(346)
	Repayments from/(Advances to) External Entities	(57)	(51)	(45)
	Proceeds from Partnership Issuances	44	50	44
	Sinking Fund Withdrawals	165	0	0
	Sinking Fund Payment	(165)	(213)	(254)
	Other	(11)	(0)	0
	Cash Provided by Financing Activities	2 833	2 567	1 749
	INVESTING ACTIVITIES			
	Additions to Capital Assets	(2 610)	(2 465)	(1 523)
	Additions to Intangible Assets	(133)	(225)	(198)
	Additions to Regulatory Deferral Balances	(93)	(90)	(127)
	Contributions Received	194	57	13
	Cash Paid to the City	(16)	(16)	(16)
	Cash Paid for Mitigation and Major Development Liabilities	(46)	(130)	(68)
	Other	(3)	(0)	(0)
	Cash Used for Investing Activities	(2 706)	(2 869)	(1 918)
	Net Increase (Decrease) in Cash	(4)	(43)	73
	Cash at Beginning of Year	634	574	530
	Cash at End of Year	629	530	604

c) Please see the schedule below which indicates the amount of financing required to fund Major New Generation & Transmission projects for 2017/18, 2018/19 and 2019/20.

	For the year ended March 31	ACTUAL 2018	OUTLOOK 2019	INTERIM BUDGET 2020
A	**Cash Provided by Operating Activities**	(132.0)	259.6	242.2
B	**Capitalized Interest**	342.0	284.9	315.0
C = (A+B)	**Cash Flow used in Operations**	210.0	544.5	557.1
D	**Business Operations Capital Spending**	461.0	515.0	510.5
E = C-D	**Excess Cash Flow after Business Operations Capital Spending**	(251.0)	29.5	46.6
F = C/D	**Capital Coverage Ratio**	0.46	1.06	1.09
G	**Major New Generation & Transmission**	2 463.0	2 092.5	1 214.4
H	**Financing Required to Fund MNG&T**	2 714.0	2 062.9	1 167.8

It is noted that while Manitoba Hydro no longer classifies capitalized interest under Cash used for Investing Activities in its Cash Flow Statement, the calculation of the capital coverage ratio has not changed from how the ratio has been determined in prior years. Manitoba Hydro omits all capitalized interest from Cash Flow from Operations in determining the internally generated funds used in the capital coverage calculation, as illustrated in Figure 4 above.

Notably, the capital coverage ratio omits all capitalized interest and other non-discretionary cash requirements (e.g. ongoing payment to the City of Winnipeg, mitigation payments etc.) and as a result, it overstates the margin the corporation has to meet its sustaining capital expenditures including associated financing costs.

REFERENCE:

2017/18 GRA PUB MFR 18 and PUB/MH I-33

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide charts and respective data tables for each of the financial ratios for electric operations for 2017/18, 2018/19 and 2019/20.
b) Provide details of the determination of each of the financial ratios for electric operations for 2017/18, 2018/19 and 2019/20. Include the detail to allow for a reconciliation of the determination of each financial target with the same level of detail as PUB/MH I-33.
c) Provide a schedule in the format of PUB MFR 51 that indicates the amount of cash flow from electric operations (excluding capitalized interest in the calculation thereof), forecast electric base capital spending, and net cash flow available to finance each Major Generation & Transmission Project in 2017/18 through the test year. Include the (electric) capital coverage ratio consistent with the determination of the ratio in prior years.

RESPONSE:

a) and b)

The Figures have been updated to reflect the financial projections filed with the PUB on February 14, 2019 as part of Supplement to the 2019/20 Electric Rate Application.

Figure 1. Debt Ratio Calculation

Debt Ratio
Manitoba Hydro (Electric Only)
($ millions)

	A	B	C	D	E	F	G	H	(E-F+G-H) / (A+B+C+D+E-F+G-H)
Fiscal Year Ended	Retained Earnings	Unamortized Customer Contributions*	Accumulated Other Comprehensive Income	Non-Controlling Interest	Long-Term Debt	Sinking Fund Investment	Short-Term Debt	Short-Term Investments	Debt Ratio
2018	2 767	797	(688)	205	18 830	-	50	629	0.86
2019	2 862	830	(711)	253	20 916	-	-	678	0.86
2020	2 977	761	(675)	294	22 832	84	-	737	0.87

*2017/18 includes current portion of deferred revenue and a $29M FMV adjustment related to the acquisition of Centra Gas.

References in Projected Financial Statements:

Col A: Figure 5, Electric Operations Projected Balance Sheet, Retained Earnings
Col B: Figure 5, Electric Operations Projected Balance Sheet, Deferred Revenue plus Bipole III Reserve Account (including the current portion)
Col C: Figure 5, Electric Operations Projected Balance Sheet, Accumulated Other Comprehensive Income
Col D: Figure 5, Electric Operations Projected Balance Sheet, Non-Controlling Interests
Col E: Figure 2, Column C
Col F: Figure 5, Electric Operations Projected Balance Sheet, Sinking Fund Investments
Col G: Figure 5, Electric Operations Projected Balance Sheet, Short-Term Debt
Col H: Figure 5, Electric Operations Projected Balance Sheet, Cash and Cash Equivalents

Figure 2. Long-Term Debt Calculation

Calculation of Long-Term Debt
for input into Debt:Equity Ratio
($ millions)

	A	B	C (A+B)
Fiscal Year Ended	Long-Term Debt	Current Portion of Long-Term Debt	Long-Term Debt
2018	17 830	1 000	18 830
2019	20 709	207	20 916
2020	21 530	1 303	22 832

*Long-Term Debt includes a $17M FMV adjustment for Centra Gas acquisition.

References in Projected Financial Statements:

Col A: Figure 5, Electric Operations Projected Balance Sheet, Long-Term Debt
Col B: Figure 5, Electric Operations Projected Balance Sheet, Current Portion of Long-Term Debt

Figure 3. EBITDA Interest Coverage Ratio Calculation

EBITDA Interest Coverage
Electric
($ millions)

	A	B	C	D	(A+B+C+D)/(B+C)
Fiscal Year Ended	Electric Net Income	Electric Finance Expense (net)	Electric Capitalized Interest	Electric Depreciation Expense	Electric EBITDA Interest Coverage
2018	18	584	342	407	1.46
2019	95	718	275	488	1.59
2020	115	748	311	530	1.61

References in Projected Financial Statements:
Col A: Figure 5, Electric Operations Projected Operating Statement, Net Income Attributable to Manitoba Hydro
Col B: Figure 5, Electric Operations Projected Operating Statement, Finance Expense less Finance Income plus Finance Expense Corporate Allocation
Col C: Figure 5, Electric Operations Projected Operating Statement, Capitalized Interest
Col D: Figure 5, Electric Operations Projected Operating Statement, Depreciation and Amortization plus Depreciation Corporate Allocation minus Depreciation & Amortization in Net Movement

Figure 4. Capital Coverage Ratio Calculation

Capital Coverage Ratio
Excluding Major Generation
Electric
($ millions)

	A	B	C (A+B)	D	E (C/D)
Fiscal Year Ended	Electric Funds from Operations	Electric Capitalized Interest	Electric Internally Generated Funds	Electric Capital Expenditures	Electric Capital Coverage
2018	(132)	342	210	461	0.46
2019	326	275	600	478	1.26
2020	331	311	642	478	1.34

References in Projected Financial Statements:
Col A: Figure 5, Electric Operations Projected Cash Flow Statement, Cash Flow from Operating Activities
Col B: Figure 5, Electric Operations Projected Operating Statement, Capitalized Interest
Col D: 2019/20 Electric Rate Application - Supplement to the Application, Section 4.0

Figure 5. Projected Financial Statements

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

			ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
		For the year ended March 31			
		REVENUES			
		Domestic Revenue			
		at approved rates	1 616	1 703	1 699
		additional	-	-	50
		BPIII Reserve Account	(152)	(44)	-
		Extraprovincial	437	432	418
		Other	30	85	105
			1 931	2 175	2 272
		EXPENSES			
		Operating and Administrative	517	501	511
		Gross Finance Expense	*943*	*1 018*	*1 090*
Figure 3	Column C	*Capitalized Interest*	*(342)*	*(275)*	*(311)*
Figure 3	Column B	Finance Expense	601	743	779
Figure 3	Column B	Finance Income	(23)	(31)	(38)
Figure 3	Column D	Depreciation and Amortization	402	465	505
		Water Rentals and Assessments	126	114	117
		Fuel and Power Purchased	130	135	127
		Capital and Other Taxes	130	140	148
		Other Expenses	501	79	74
Figure 3	Column B	*Finance Expense*	*6*	*6*	*6*
Figure 3	Column D	*Depreciation and Amortization*	*1*	*1*	*1*
		Other Revenues	*0*	*0*	*0*
		Corporate Allocation	8	8	8
			2 393	2 154	2 233
		Net Income before Net Movement in Reg. Deferral	(462)	22	40
		Operating and Administrative	*20*	*20*	*20*
Figure 3	Column D	*Depreciation and Amortization*	*(3)*	*(21)*	*(23)*
		Other Expenses	*454*	*72*	*73*
		Net Movement in Regulatory Deferral	472	70	70
		Net Income	10	92	110
		Net Income Attributable to:			
Figure 3	Column A	**Manitoba Hydro**	**18**	**95**	**115**
		Non-controlling Interest	(8)	(3)	(4)
			10	92	110
		PUB Approved Percent Increase	3.36%	3.60%	-
		Proposed Percent Increase	-	-	3.50%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
(In Millions of Dollars)

		For the year ended March 31	**ACTUAL 2018**	**CURRENT OUTLOOK 2019**	**APPROVED BUDGET 2020**
		ASSETS			
		Plant in Service	13 681	18 528	19 134
		Accumulated Depreciation	(1 302)	(1 715)	(2 171)
		Net Plant in Service	12 380	16 813	16 963
		Construction in Progress	8 995	6 261	7 658
Figure 1	Column H	*Cash and Cash Equivalents*	*629*	*678*	*737*
		Other Current Assets	*510*	*505*	*536*
Figure 1	Column F	*Sinking Fund Investments*	*0*	*0*	*84*
		Other Non-Current Assets	*653*	*731*	*784*
		Current and Other Assets	1 792	1 913	2 141
		Goodwill and Intangible Assets	440	648	857
		Total Assets before Regulatory Deferral	23 607	25 635	27 619
		Regulatory Deferral Balance	933	955	1 025
			24 540	26 590	28 644
		LIABILITIES AND EQUITY			
Figure 2	Column A	Long-Term Debt	17 813	20 709	21 530
Figure 2	Column B	*Current Portion of Long-Term Debt*	*1 000*	*207*	*1 303*
Figure 1	Column G	*Short-Term Debt*	*50*	*0*	*0*
		Other Current Liabilities	*1 008*	*853*	*838*
Figure 1	Column D	*Non-Controlling Interests*	*205*	*253*	*294*
		Other Non-Current Liabilities	*1 515*	*1 627*	*1 660*
		Current and Other Liabilities	3 777	2 941	4 095
		Provisions	60	48	47
Figure 1	Column B	Deferred Revenue*	467	486	495
Figure 1	Column B	BPIII Reserve Account*	294	255	177
Figure 1	Column A	Retained Earnings	2 767	2 862	2 977
Figure 1	Column C	Accumulated Other Comprehensive Income	(688)	(711)	(675)
		Total Liabilities and Equity before Regulatory Deferral	24 491	26 590	28 644
		Regulatory Deferral Balance	49	-	-
			24 540	26 590	28 644

* These balances are net of the current portions of Deferred Revenue and the BPIII Reserve Account which are now included under Current and Other Liabilities.

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

	For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
	OPERATING ACTIVITIES			
	Cash Receipts from Customers	1 883	2 111	2 187
	Cash Paid to Suppliers and Employees	(1 158)	(836)	(843)
	Interest Paid	(880)	(964)	(1 028)
	Interest Received	23	14	16
Figure 4 Column A	**Cash Provided by Operating Activities**	(132)	326	331
	FINANCING ACTIVITIES			
	Proceeds from Long-Term Debt	3 441	3 852	2 150
	Retirement of Long-Term Debt	(583)	(1 775)	(227)
	Repayments from/(Advances to) External Entities	(57)	(52)	(45)
	Proceeds from Partnership Issuances	44	51	44
	Sinking Fund Withdrawals	165	193	130
	Sinking Fund Payment	(165)	(193)	(214)
	Other	(11)	0	0
	Cash Provided by Financing Activities	2 833	2 076	1 838
	INVESTING ACTIVITIES			
	Additions to Capital Assets	(2 610)	(1 933)	(1 735)
	Additions to Intangible Assets	(133)	(219)	(207)
	Additions to Regulatory Deferral Balances	(93)	(93)	(94)
	Contributions Received	194	62	13
	Cash Paid to the City	(16)	(16)	(16)
	Cash Paid for Mitigation and Major Development Liabilities	(46)	(104)	(69)
	Other	(3)	(1)	(0)
	Cash Used for Investing Activities	(2 706)	(2 303)	(2 110)
	Net Increase (Decrease) in Cash	(4)	98	59
	Cash at Beginning of Year	634	579	678
	Cash at End of Year	629	678	737

c) Please see the schedule below which indicates the amount of financing required to fund Major New Generation & Transmission projects for 2017/18, 2018/19 and 2019/20. The schedule has been updated to reflect the financial projections filed with the PUB on February 14, 2019 as part of Supplement to the 2019/20 Electric Rate Application.

	For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
A	**Cash Provided by Operating Activities**	(132)	326	331
B	**Capitalized Interest**	342	275	311
C = (A+B)	**Cash Flow used in Operations**	210	601	642
D	**Business Operations Capital Spending**	461	478	478
E = C-D	**Excess Cash Flow after Business Operations Capital Spending**	(251)	123	164
F = C/D	**Capital Coverage Ratio**	0.46	1.26	1.34
G	**Major New Generation & Transmission**	2 463	1 625	1 521
H	**Financing Required to Fund MNG&T**	2 714	1 502	1 357

It is noted that while Manitoba Hydro no longer classifies capitalized interest under Cash used for Investing Activities in its Cash Flow Statement, the calculation of the capital coverage ratio has not changed from how the ratio has been determined in prior years. Manitoba Hydro omits all capitalized interest from Cash Flow from Operations in determining the internally generated funds used in the capital coverage calculation, as illustrated in Figure 4 above.

Notably, the capital coverage ratio omits all capitalized interest and other non-discretionary cash requirements (e.g. ongoing payment to the City of Winnipeg, mitigation payments etc.) and as a result, it overstates the margin the corporation has to meet its sustaining capital expenditures including associated financing costs.

REFERENCE:

2017/18 GRA PUB MFR 20

PREAMBLE TO IR (IF ANY):

QUESTION:

In the format used in the response to PUB MFR 20 (2017/18 & 2018/19 GRA), provide 5 year forecasts of revenue requirements including cost components (Finance/Depreciation/Operating/Water Rentals/F&PP/Taxes) for:

- Keeyask generating station
- Manitoba-Minnesota Transmission Project
- Great Northern Transmission Line
- Bipole III and Riel station
- Sunk costs related to Conawapa
- DSM
- Sustaining Capital

RESPONSE:

Portions of this response contain information considered to be confidential and commercially sensitive. The confidential portions have been highlighted, and those portions redacted in the public version of this response.

This IR seeks to simulate the Revenue Requirement impact of individual Major New Generation and Transmission projects.

The most reliable measure of Manitoba Hydro's revenue requirement is the additional Domestic Revenue indicated on the electric operations projected operating statement (Appendix 1, page 1 of 4) which is derived based on balancing the costs of the integrated hydro-electric system, for new asset additions as well as existing assets, with maintaining minimum financial ratios as well as rate stability and affordability for customers.

The type of analysis requested in this IR is limited by virtue of treating individual projects on an incremental cost basis. While costs such as Depreciation Expense, Water Rentals, and Operating & Administrative Expenses may be estimated and may be directly attributable to a Major New Generation and Transmission asset, other costs such as Finance Expense, capital taxes and benefits are not readily estimated on an incremental basis. Furthermore, this analysis disregards the estimated export revenues to be obtained through sales of surplus energy associated with new electric generating plant.

Notwithstanding the concerns identified above, the requested analysis has been provided in the tables below. Reliance on the estimated carrying and operating costs in these schedules as a representation of revenue requirement must be viewed with caution considering the inherent limitations of the analysis, estimation assumptions and methods described below.

1. Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, finance expense attributable to a specific project is estimated for the purposes of this analysis by applying Manitoba Hydro's average cost of debt to the asset's net book value (projected in-service cost net of accumulated depreciation). Using the net book value as the principal outstanding for debt associated with an asset assumes that annual depreciation expense approximates revenues available to reduce debt over the life of the asset. This estimation method does not consider that extraprovincial revenues partially offset the costs. As a result, the implied impacts to customers for each project may not be representative.

2. Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as a proxy for paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

3. Manitoba Hydro operates the integrated hydro-electric system to optimize the efficient use of water resources and maximize overall Corporate revenues for the benefit of customers. The output of one facility may not be maximized on its own but contributes to the maximization of the system as a whole. The assumption that depreciation expense approximates the revenue attributable to a project may be reasonable for understanding costs but does not reflect the value of a particular asset to the integrated system and should not be used for resource planning purposes.

4. The analysis considers only the prospective costs of asset additions and does not address the ability of revenues at current PUB approved rates to cover ongoing carrying and operating costs of existing assets. Current domestic rates are lower than what they otherwise would have been due to extraprovincial revenues partially offsetting costs. In years of low water flow or low opportunity export prices, domestic revenues are not sufficient to cover the resulting reduction in extraprovincial revenues.

5. The analysis does not consider any contributions to reserves.

Considering the above, the summation of total costs in the following tables may not accurately reflect the overall revenue requirement for Manitoba Hydro or how a particular asset contributes to the Corporation's overall revenue requirement.

KEEYASK (ISD 2021/22)
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	-	-	-	119	322
OM&A Costs	-	-	-	9	16
Depreciation	-	-	-	21	99
Capital Tax	29	34	38	42	43
Water Rentals	-	-	-	5	15
	29	34	38	196	495

MANITOBA-MINNESOTA TRANSMISSION PROJECT
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	0	1	11	21	21
OM&A Costs	-	-	0	0	0
Depreciation	0	0	6	7	7
Transmission Charges	-	-	-	-	-
Capital Tax	1	2	2	2	2
	2	2	19	31	30

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	[redacted]				
OM&A Costs					
Amortization					
Transmission Charges					
Capital Tax					
	2	3	75	101	98

3a

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	133	240	243	246	240
OM&A Costs	8	13	13	13	14
Depreciation	77	108	107	106	106
Amortization of BPIII Reserve	(59)	(78)	(78)	(78)	(78)
Capital Tax	24	24	24	24	24
	184	307	309	312	306

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	18	17	17	16	15
Amortization	13	13	13	13	13
	30	29	29	29	28

DSM
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	4	8	11	14	16
OM&A Costs	1	1	1	1	1
Amortization	6	13	22	31	40
Capital Tax	1	1	1	2	2
	12	22	36	48	59

BUSINESS OPERATIONS CAPITAL
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	30	47	65	80	91
Depreciation	22	38	55	71	87
Capital Tax	8	10	13	15	17
	60	96	132	166	196

REFERENCE:

2017/18 GRA PUB MFR 20

PREAMBLE TO IR (IF ANY):

QUESTION:

In the format used in the response to PUB MFR 20 (2017/18 & 2018/19 GRA), provide 5 year forecasts of revenue requirements including cost components (Finance/Depreciation/Operating/Water Rentals/F&PP/Taxes) for:

- Keeyask generating station
- Manitoba-Minnesota Transmission Project
- Great Northern Transmission Line
- Bipole III and Riel station
- Sunk costs related to Conawapa
- DSM
- Sustaining Capital

RESPONSE:

Portions of this updated response contain information which is confidential and commercially sensitive. This response is being filed in confidence consistent with the PUB's ruling in its letter of February 5, 2019. The confidential portions have been highlighted, and those portions redacted in the public version of this response.

This IR seeks to simulate the Revenue Requirement impact of individual Major New Generation and Transmission projects. The IR has been updated based on the financial projections filed on February 14, 2019 as part of Supplement to the 2019/20 Electric Rate Application.

The most reliable measure of Manitoba Hydro's revenue requirement is the additional Domestic Revenue indicated on the electric operations projected operating statement (Appendix 1 (Updated), page 1 of 4) which is derived based on balancing the costs of the integrated hydro-electric system, for new asset additions as well as existing assets, with maintaining minimum financial ratios as well as rate stability and affordability for customers.

The type of analysis requested in this IR is limited by virtue of treating individual projects on an incremental cost basis. While costs such as Depreciation Expense, Water Rentals, and Operating & Administrative Expenses may be estimated and may be directly attributable to a Major New Generation and Transmission asset, other costs such as Finance Expense, capital taxes and benefits are not readily estimated on an incremental basis. Furthermore, this analysis disregards the estimated export revenues to be obtained through sales of surplus energy associated with new electric generating plant.

Notwithstanding the concerns identified above, the requested analysis has been provided in the tables below. Reliance on the estimated carrying and operating costs in these schedules as a representation of revenue requirement must be viewed with caution considering the inherent limitations of the analysis, estimation assumptions and methods described below.

1. Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, finance expense attributable to a specific project is estimated for the purposes of this analysis by applying Manitoba Hydro's average cost of debt to the asset's net book value (projected in-service cost net of accumulated depreciation). Using the net book value as the principal outstanding for debt associated with an asset assumes that annual depreciation expense approximates revenues available to reduce debt over the life of the asset. This estimation method does not consider that extraprovincial revenues partially offset the costs. As a result, the implied impacts to customers for each project may not be representative.

2. Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as a proxy for paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

3. Manitoba Hydro operates the integrated hydro-electric system to optimize the efficient use of water resources and maximize overall Corporate revenues for the benefit of customers. The output of one facility may not be maximized on its own but contributes to the maximization of the system as a whole. The assumption that depreciation expense approximates the revenue attributable to a project may be reasonable for understanding costs but does not reflect the value of a particular asset to the integrated system and should not be used for resource planning purposes.

4. The analysis considers only the prospective costs of asset additions and does not address the ability of revenues at current PUB approved rates to cover ongoing carrying and operating costs of existing assets. Current domestic rates are lower than what they otherwise would have been due to extraprovincial revenues partially offsetting costs. In years of low water flow or low opportunity export prices, domestic revenues are not sufficient to cover the resulting reduction in extraprovincial revenues.

5. The analysis does not consider any contributions to reserves.

Considering the above, the summation of total costs in the following tables may not accurately reflect the overall revenue requirement for Manitoba Hydro or how a particular asset contributes to the Corporation’s overall revenue requirement.

KEEYASK (ISD 2021/22)
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	-	-	-	119	329
OM&A Costs	-	-	-	9	16
Depreciation	-	-	-	21	99
Capital Tax	29	35	39	42	43
Water Rentals	-	-	-	5	14
	29	35	39	196	502

MANITOBA-MINNESOTA TRANSMISSION PROJECT
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	0	1	11	22	21
OM&A Costs	-	-	-	0	0
Depreciation	0	0	5	7	7
Transmission Charges	-	-	-	-	-
Capital Tax	1	2	2	2	2
	1	3	19	31	31

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	[redacted]				
OM&A Costs					
Amortization					
Transmission Charges					
Capital Tax					
	2	3	74	99	97

3a

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	124	222	227	233	233
OM&A Costs	8	13	13	13	14
Depreciation	70	101	102	103	103
Amortization of BPIII Reserve	(58)	(78)	(78)	(78)	(78)
Capital Tax	22	23	23	23	23
	166	280	287	294	294

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	18	17	17	16	16
Amortization	13	13	13	13	13
	31	30	29	29	28

DSM
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	3	4	7	11	14
OM&A Costs	1	1	1	1	1
Amortization	-	6	12	21	30
Capital Tax	1	2	2	2	3
	5	13	23	36	47

BUSINESS OPERATIONS CAPITAL
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	10	28	44	60	75
Depreciation	8	24	39	55	71
Capital Tax	5	7	10	12	15
	22	59	92	127	160

REFERENCE:

Appendix 1; PUB/MH 1, MIPUG/MH I-6b (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Supplement the schedule provided to include the opening and closing balances of each regulatory deferral account.
b) Provide details of and explain the site restoration costs forecast for 2018/19 and 2019/20 and compare with the forecast of those costs for those years presented at the last GRA.
c) Provide a comparison of the details of additions and amortizations to regulatory deferral accounts for 2017/18, 2018/19 and 2019/20 and explain the differences.

RESPONSE:

a) Please see the following for a continuity schedule providing the opening and closing balances for each regulatory deferral account.

Manitoba Hydro 2019/20 Electric Rate Application (In thousands of dollars)	2017/18 Actual	2018/19 Outlook	2019/20 Interim Budget
Opening balance of net regulatory deferral			
Demand side management expenses	204 389	232 817	257 961
Site restoration costs	27 956	27 317	29 656
Regulatory costs	5 410	12 921	12 694
Acquisition costs	9 788	9 096	8 404
Change in depreciation method	90 827	124 496	163 349
Deferred ineligible overhead	60 600	78 721	96 247
Loss on disposal of assets	9 641	9 118	8 595
Affordable Energy Fund	4 164	4 164	3 506
Discontinuance of Conawapa Generating Station	-	379 758	367 112
DSM deferral debit balance	48 800	-	-
DSM deferral credit balance	(48 800)	-	-
	412 775	878 406	947 522
Additions to regulatory deferral accounts			
Demand side management expenses	63 667	62 539	94 251
Site restoration costs	1 221	6 421	11 201
Regulatory costs	10 136	2 476	2 832
Acquisition costs	-	-	-
Change in depreciation method	32 270	38 853	41 912
Deferred ineligible overhead	20 200	20 200	20 200
Loss on disposal of assets	8 534	-	
Affordable Energy Fund	76	-	
Discontinuance of Conawapa Generating Station	379 204	-	-
DSM deferral debit balance	-		
DSM deferral credit balance	-		
	515 308	130 489	170 396
Amortization of regulatory deferral accounts			
Demand side management expenses	(35 773)	(37 395)	(40 249)
Site restoration costs	(3 480)	(4 082)	(4 270)
Regulatory costs	(1 520)	(2 703)	(5 366)
Acquisition costs	(692)	(692)	(692)
Change in depreciation method	-	-	-
Deferred ineligible overhead	(2 079)	(2 674)	(3 268)
Loss on disposal of assets	-	(523)	(523)
Affordable Energy Fund	(197)	(658)	(462)
Discontinuance of Conawapa Generating Station	-	(12 646)	(12 646)
DSM deferral debit balance	-	-	-
DSM deferral credit balance	-	-	-
	(43 741)	(61 373)	(67 476)
Closing balance of net regulatory deferral			
Demand side management expenses	232 283	257 961	311 963
Site restoration costs	25 697	29 656	36 587
Regulatory costs	14 026	12 694	10 160
Acquisition costs	9 096	8 404	7 712
Change in depreciation method	123 097	163 349	205 261
Deferred ineligible overhead	78 721	96 247	113 179
Loss on disposal of assets	18 175	8 595	8 072
Affordable Energy Fund	4 043	3 506	3 044
Discontinuance of Conawapa Generating Station	379 204	367 112	354 466
DSM deferral debit balance	48 800	-	-
DSM deferral credit balance	(48 800)	-	-
	884 342	947 522	1 050 442

b) Please see the following schedule for the details comprising site restoration costs for the 2018/19 Outlook and the 2019/20 Interim Budget and for those same years as presented at the last GRA (MH16 Update with Interim Forecast). Explanations for the differences are provided below the schedule.

	Manitoba Hydro 2019/20 Electric Rate Application		Manitoba Hydro 2017/18 & 2018/19 GRA MH16 Update with Interim			
(In thousands of dollars)	2018/19 Outlook	2019/20 Interim Budget	2018/19 Forecast	2019/20 Forecast	2018/19 Difference	2019/20 Difference
Site Restoration Costs						
8 and 2 Mile Channel cleanup	4 490	6 380	949	280	3 541	6 100
South Bay construction camp	152	3 971	904	280	(752)	3 691
Other	1 779	850	850	852	929	(2)
	6 421	**11 201**	**2 703**	**1 412**	**3 718**	**9 789**

2018/19 Outlook vs. 2018/19 MH16 Update with Interim Forecast

The increase in the 2018/19 Outlook compared to the 2018/19 MH16 Update with Interim Forecast filed at the last GRA is due primarily to an increase in the spending for the 8 & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations which identified additional work to be performed. In addition, the 2018/19 Outlook for Other site restoration costs is higher due to efforts required to review and address any issues associated with the recent closures of rural district offices and to accommodate the replacement of aging infrastructure. These increases are partially offset by a reduction in the 2018/19 Outlook for the South Bay construction camp as the plans for this site have been delayed subject to further studies and discussions with the community.

2019/20 Interim Budget vs. 2019/20 MH16 Update with Interim Forecast

The increase in the 2019/20 Interim Budget compared to the 2019/20 MH16 Update with Interim Forecast is due primarily to increased spending for the 8 & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations. The increase in the 2019/20 Interim Budget for the South Bay construction camp reflects the start of previous year's deferred projects.

c) Please see the following schedule which details the additions and amortization to regulatory deferral accounts for 2017/18 actuals, 2018/19 Outlook and 2019/20 Interim Budget compared to the previous MH16 Update with Interim Forecast for those same years. Explanations as to the year over year differences are provided below.

	Manitoba Hydro 2019/20 Electric Rate Application			Manitoba Hydro MH16 Update with Interim					
(In thousands of dollars)	**2017/18 Actual**	**2018/19 Outlook**	**2019/20 Interim Budget**	**2017/18 Forecast**	**2018/19 Forecast**	**2019/20 Forecast**	**2017/18 Difference**	**2018/19 Difference**	**2019/20 Difference**
Additions to regulatory deferral accounts									
Demand side management expenses	63 667	62 539	94 251	57 184	99 404	94 251	6 483	(36 865)	-
Site restoration costs	1 221	6 421	11 201	2 794	2 703	1 408	(1 573)	3 718	9 793
Regulatory costs	10 136	2 476	2 832	3 664	2 339	1 339	6 472	137	1 493
Acquisition costs	-	-	-	-	-	-	-	-	-
Change in depreciation method	32 270	38 853	41 912	33 952	39 506	42 869	(1 682)	(653)	(957)
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-
Loss on disposal of assets	8 534	-		-	-	-	8 534	-	-
Affordable Energy Fund	76	-		-	-	-	76	-	-
Discontinuance of Conawapa Generating Station	379 204	-	-	-	-	379 758	379 204	-	(379 758)
DSM deferral debit balance	-			-	-	-	-	-	-
DSM deferral credit balance	-			-	-	-	-	-	-
	515 308	**130 489**	**170 396**	**117 794**	**164 152**	**539 825**	**397 514**	**(33 663)**	**(369 429)**
Amortization of regulatory deferral accounts									
Demand side management expenses	(35 773)	(37 395)	(40 249)	(35 742)	(36 662)	(43 202)	(31)	(733)	2 953
Site restoration costs	(3 480)	(4 082)	(4 270)	(4 106)	(3 990)	(3 855)	626	(92)	(415)
Regulatory costs	(1 520)	(2 703)	(5 366)	(2 942)	(3 665)	(2 884)	1 422	962	(2 482)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	-	-	-
Change in depreciation method	-	-	-	-	-	(6 437)	-	-	6 437
Deferred ineligible overhead	(2 079)	(2 674)	(3 268)	(1 768)	(4 545)	(5 555)	(311)	1 871	2 287
Loss on disposal of assets	-	(523)	(523)	(288)	(577)	(577)	288	54	54
Affordable Energy Fund	(197)	(658)	(462)	(449)	(480)	(563)	252	(178)	101
Discontinuance of Conawapa Generating Station	-	(12 646)	(12 646)	-		(11 592)	-	(12 646)	(1 054)
DSM deferral debit balance	-	-	-	-		-	-	-	-
DSM deferral credit balance	-	-	-	-		-	-	-	-
	(43 741)	**(61 373)**	**(67 476)**	**(45 987)**	**(50 611)**	**(75 357)**	**2 246**	**(10 762)**	**7 881**

Year over Year Explanations

2017/18 Actual vs. 2017/18 MH16 Update with Interim Forecast

Additions:

The 2017/18 additions were higher than the MH16 Update with Interim Forecast primarily as a result of the March 31, 2018 transfer of the Conawapa Generating Station (GS) development costs from Construction Work in Progress (CWIP) to a regulatory deferral account, as per PUB Order 59/18. The forecast had assumed this transfer would occur in fiscal 2019/20. In addition, losses on the disposal of assets were higher as the forecast did not include a projection for losses. The losses are the result of the retirement of equipment at the Limestone Generating Station and the St. James station, as well as the retirement of street lights replaced with LED bulbs. The 2017/18 DSM spending was higher than the forecast due to greater than anticipated take up in commercial lighting and solar technology programs, as well as higher than projected installations of LED roadway lighting. Actual regulatory costs for the 2017/18 & 2018/19 GRA were also higher than the forecast.

Amortization:

The 2017/18 amortization was lower than the MH16 Update with Interim Forecast primarily as a result of the amortization of the 2017/18 & 2018/19 GRA regulatory costs commencing in June 2018 to coincide with the implementation date of the rate increase, as compared to the October 2017 date assumed in the forecast. In addition, there was lower amortization for site restoration costs as the previous year's site restoration costs were lower than projected.

2018/19 Outlook vs. 2018/19 MH16 Update with Interim Forecast

Additions:

The additions for the 2018/19 Outlook are lower than the MH16 Update with Interim Forecast due primarily to a reduction in planned DSM spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. The reduction in DSM spending is partially offset by increases in site restoration costs due to additional work for the 8 & 2 mile channel as identified in recent environmental and geophysical investigations.

Amortization:

The amortization for the 2018/19 Outlook is higher than the MH16 Update with Interim Forecast primarily as a result of the timing of the deferral of the Conawapa GS regulatory account as discussed above. This increase is partially offset by the decrease in the amortization of the ineligible overhead which is being amortized over a 34 year period (as per PUB Order 59/18) compared to the 20 year period assumed in the forecast.

2019/20 Interim Budget vs. 2019/20 MH16 Update with Interim Forecast

Additions:

The additions for the 2019/20 Interim Budget are lower than the balances presented in the MH16 Update with Interim Forecast primarily because of the difference in the timing of the transfer of the Conawapa CWIP costs to a regulatory deferral account. This decrease is partially offset by an increase in projected spending for site restoration costs as discussed above.

Amortization:

The amortization for the 2019/20 Interim Budget period is lower than the MH16 Update with Interim Forecast primarily due to the reduction in the annual amortization of the change in depreciation method (ASL vs. ELG) regulatory deferral account. The depreciation deferral account is not being amortized (as per PUB Order 59/18) as compared to the 20 year period (commencing in 2019/20) assumed in the forecast. In addition, the amortization for DSM expenditures is lower compared to forecast due to the planned reductions in DSM expenditures in 2018/19. The amortization for the ineligible overhead account is lower due to the use of a 34 year amortization period as discussed above. These decreases are partially offset by an increase in the amortization of regulatory costs reflecting the higher than planned expenditures for the 2017/18 & 2018/19 GRA.

REFERENCE:

Appendix 1; PUB/MH 1, MIPUG/MH I-6b (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Supplement the schedule provided to include the opening and closing balances of each regulatory deferral account.
b) Provide details of and explain the site restoration costs forecast for 2018/19 and 2019/20 and compare with the forecast of those costs for those years presented at the last GRA.
c) Provide a comparison of the details of additions and amortizations to regulatory deferral accounts for 2017/18, 2018/19 and 2019/20 and explain the differences.

RESPONSE:

a) Please see the following for a continuity schedule providing the opening and closing balances for each regulatory deferral account.

Manitoba Hydro
Supplement to the 2019/20 Electric Rate Application
(In thousands of dollars)

	Actual 2017/18	Current Outlook 2018/19	Approved Budget 2019/20
Opening balance of net regulatory deferral			
Demand side management expenses	204 389	232 283	257 481
Site restoration costs	27 956	25 697	29 125
Regulatory costs	5 410	14 026	11 438
Acquisition costs	9 788	9 096	8 404
Change in depreciation method	90 827	123 097	161 836
Deferred ineligible overhead	60 600	78 721	96 309
Loss on disposal of assets	9 641	18 175	20 175
Affordable Energy Fund	4 164	4 043	3 385
Discontinuance of Conawapa Generating Station	-	379 204	366 577
DSM deferral debit balance	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)
	412 775	884 342	954 730
Additions to regulatory deferral accounts			
Demand side management expenses	63 667	62 539	61 219
Site restoration costs	1 221	7 355	6 722
Regulatory costs	10 136	1 733	5 282
Acquisition costs	-	-	-
Change in depreciation method	32 270	38 739	41 776
Deferred ineligible overhead	20 200	20 200	20 200
Loss on disposal of assets	8 534	2 000	2 000
Affordable Energy Fund	76	-	
Discontinuance of Conawapa Generating Station	379 204	-	-
DSM deferral debit balance	-		
DSM deferral credit balance	-		
	515 308	132 566	137 199
Amortization of regulatory deferral accounts			
Demand side management expenses	(35 773)	(37 341)	(40 195)
Site restoration costs	(3 480)	(3 927)	(4 065)
Regulatory costs	(1 520)	(4 321)	(4 493)
Acquisition costs	(692)	(692)	(692)
Change in depreciation method	-	-	-
Deferred ineligible overhead	(2 079)	(2 612)	(3 206)
Loss on disposal of assets	-	-	(1 059)
Affordable Energy Fund	(197)	(658)	(437)
Discontinuance of Conawapa Generating Station	-	(12 627)	(12 627)
DSM deferral debit balance	-	-	-
DSM deferral credit balance	-	-	-
	(43 741)	(62 178)	(66 774)
Closing balance of net regulatory deferral			
Demand side management expenses	232 283	257 481	278 505
Site restoration costs	25 697	29 125	31 782
Regulatory costs	14 026	11 438	12 227
Acquisition costs	9 096	8 404	7 712
Change in depreciation method	123 097	161 836	203 612
Deferred ineligible overhead	78 721	96 309	113 303
Loss on disposal of assets	18 175	20 175	21 116
Affordable Energy Fund	4 043	3 385	2 948
Discontinuance of Conawapa Generating Station	379 204	366 577	353 950
DSM deferral debit balance	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)
	884 342	954 730	1 025 155

b) Please see the following schedule for the details comprising site restoration costs for the 2018/19 Current Outlook and the 2019/20 Approved Budget and for those same years as presented at the last GRA (MH16 Update with Interim). Explanations for the differences are provided below the schedule.

	Manitoba Hydro Supplement to the 2019/20 Electric Rate Application		Manitoba Hydro 2017/18 & 2018/19 GRA MH16 Update with Interim			
(In thousands of dollars)	**2018/19 Current Outlook**	**2019/20 Approved Budget**	**2018/19 Forecast**	**2019/20 Forecast**	**2018/19 Difference**	**2019/20 Difference**
Site Restoration Costs						
8 and 2 Mile Channel cleanup	5 488	4 490	949	280	4 539	4 210
South Bay construction camp	150	185	904	280	(754)	(95)
Other	1 717	2 047	850	852	867	1 196
	7 355	**6 722**	**2 703**	**1 412**	**4 652**	**5 310**

2018/19 Current Outlook vs. 2018/19 MH16 Update with Interim

The increase in the 2018/19 Current Outlook compared to the 2018/19 MH16 Update with Interim Forecast filed at the last GRA is due primarily to an increase in the spending for the 8 & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations which identified additional work to be performed. In addition, the 2018/19 Current Outlook for Other site restoration costs is higher due to efforts required to review and address any issues associated with the recent closures of rural district offices and to accommodate the replacement of aging infrastructure. These increases are partially offset by a reduction in the 2018/19 Current Outlook for the South Bay construction camp as the plans for this site have been delayed subject to further studies and discussions with the community.

2019/20 Approved Budget vs. 2019/20 MH16 Update with Interim

The increase in the 2019/20 Approved Budget compared to the 2019/20 MH16 Update with Interim Forecast is due primarily to increased spending for the 8 & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations. The 2019/20 Approved Budget for Other site restoration costs is higher due to efforts required to review and address any issues associated with the recent closures of rural district offices and to accommodate the replacement of aging infrastructure.

c) Please see the following schedule which details the additions and amortization to regulatory deferral accounts for 2017/18 actuals, 2018/19 Current Outlook and 2019/20 Approved Budget compared to the previous MH16 Update with Interim Forecast for those same years. Explanations as to the year over year differences are provided below.

	Manitoba Hydro Supplement to the 2019/20 Electric Rate Application			Manitoba Hydro MH16 Update with Interim					
(In thousands of dollars)	**Actual 2017/18**	**Current Outlook 2018/19**	**Approved Budget 2019/20**	**Forecast 2017/18**	**Forecast 2018/19**	**Forecast 2019/20**	**2017/18 Difference**	**2018/19 Difference**	**2019/20 Difference**
Additions to regulatory deferral accounts									
Demand side management expenses	63 667	62 539	61 219	57 184	99 404	94 251	6 483	(36 865)	(33 032)
Site restoration costs	1 221	7 355	6 722	2 794	2 703	1 408	(1 573)	4 652	5 314
Regulatory costs	10 136	1 733	5 282	3 664	2 339	1 339	6 472	(606)	3 943
Acquisition costs	-	-	-	-	-	-	-	-	-
Change in depreciation method	32 270	38 739	41 776	33 952	39 506	42 869	(1 682)	(767)	(1 093)
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-
Loss on disposal of assets	8 534	2 000	2 000	-	-	-	8 534	2 000	2 000
Affordable Energy Fund	76	-		-	-	-	76	-	-
Discontinuance of Conawapa Generating Station	379 204	-	-	-	-	379 758	379 204	-	(379 758)
	515 308	**132 566**	**137 199**	**117 794**	**164 152**	**539 825**	**397 514**	**(31 586)**	**(402 626)**
Amortization of regulatory deferral accounts									
Demand side management expenses	(35 773)	(37 341)	(40 195)	(35 742)	(36 662)	(43 202)	(31)	(679)	3 007
Site restoration costs	(3 480)	(3 927)	(4 065)	(4 106)	(3 990)	(3 855)	626	63	(210)
Regulatory costs	(1 520)	(4 321)	(4 493)	(2 942)	(3 665)	(2 884)	1 422	(656)	(1 609)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	-	-	-
Change in depreciation method	-	-	-	-	-	(6 437)	-	-	6 437
Deferred ineligible overhead	(2 079)	(2 612)	(3 206)	(1 768)	(4 545)	(5 555)	(311)	1 933	2 349
Loss on disposal of assets	-	-	(1 059)	(288)	(577)	(577)	288	577	(482)
Affordable Energy Fund	(197)	(658)	(437)	(449)	(480)	(563)	252	(178)	126
Discontinuance of Conawapa Generating Station	-	(12 627)	(12 627)	-		(11 592)	-	(12 627)	(1 035)
	(43 741)	**(62 178)**	**(66 774)**	**(45 987)**	**(50 611)**	**(75 357)**	**2 246**	**(11 567)**	**8 583**

Year over Year Explanations

2017/18 Actual vs. 2017/18 MH16 Update with Interim Forecast

Additions:

The 2017/18 additions were higher than the MH16 Update with Interim Forecast primarily as a result of the March 31, 2018 transfer of the Conawapa Generating Station ("GS") development costs from Construction Work in Progress ("CWIP") to a regulatory deferral account, as per PUB Order 59/18. The forecast had assumed this transfer would occur in fiscal 2019/20. In addition, losses on the disposal of assets were higher as the forecast did not include a projection for losses. The losses are the result of the retirement of equipment at the Limestone GS and the St. James station, as well as the retirement of street lights replaced with LED bulbs. The 2017/18 DSM spending was higher than the forecast due to greater than anticipated take up in commercial lighting and solar technology programs, as well as higher than projected installations of LED roadway lighting. Actual regulatory costs for the 2017/18 & 2018/19 GRA were also higher than the forecast.

Amortization:

The 2017/18 amortization was lower than the MH16 Update with Interim Forecast primarily as a result of the amortization of the 2017/18 & 2018/19 GRA regulatory costs commencing in June 2018 to coincide with the implementation date of the rate increase, as compared to the October 2017 date assumed in the forecast. In addition, there was lower amortization for site restoration costs as the previous year's site restoration costs were lower than projected.

2018/19 Current Outlook vs. 2018/19 MH16 Update with Interim Forecast

Additions:

The additions for the 2018/19 Current Outlook are lower than the MH16 Update with Interim Forecast due primarily to a reduction in planned DSM spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. The reduction in DSM spending is partially offset by increases in site restoration costs due to additional work for the 8 & 2 Mile Channel as identified in recent environmental and geophysical investigations.

Amortization:

The amortization for the 2018/19 Current Outlook is higher than the MH16 Update with Interim Forecast primarily as a result of the timing of the deferral of the Conawapa GS regulatory account as discussed above. This increase is partially offset by the decrease in the amortization of the ineligible overhead which is being amortized over a 34 year period (as per PUB Order 59/18) compared to the 20 year period assumed in the forecast.

2019/20 Approved Budget vs. 2019/20 MH16 Update with Interim Forecast

Additions:

The additions for the 2019/20 Approved Budget are lower than the balances presented in the MH16 Update with Interim Forecast primarily due to the difference in the timing of the transfer of the Conawapa CWIP costs to a regulatory deferral account and the reduction to planned DSM spending as a result of the deferral of new programs and initiatives pending the transition to Efficiency Manitoba. This decrease is partially offset by an increase in projected spending for site restoration costs as discussed above.

Amortization:

The amortization for the 2019/20 Approved Budget period is lower than the MH16 Update with Interim Forecast primarily due to the reduction in the annual amortization of the change in depreciation method (ASL vs. ELG) regulatory deferral account. The depreciation deferral account is not being amortized (as per PUB Order 59/18) as compared to the 20 year period (commencing in 2019/20) assumed in the forecast. In addition, the amortization for DSM expenditures is lower compared to forecast due to the planned reductions in DSM expenditures in 2018/19. The amortization for the ineligible overhead account is lower due to the use of a 34 year amortization period as discussed above. These decreases are partially offset by an increase in the amortization of regulatory costs reflecting the higher than planned expenditures for the 2017/18 & 2018/19 GRA.

REFERENCE:

2017/18 & 2018/19 GRA PUB/MH I-152b

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a continuity schedule of annual contributions and proposed and/or actual drawdowns of the Bipole III Deferral Account since inception.

b) Explain whether the contributions to the Bipole III Deferral Account vary depending on actual revenues (e.g. actual weather).

RESPONSE:

a) The following table provides a continuity schedule of the Bipole III deferral account, showing actual amounts deferred by fiscal year and forecasted amortization.

Bipole III Deferral Account
(in Millions of Dollars)

	Amount Deferred	Amortization	Balance
2013/14	19	-	19
2014/15	30	-	49
2015/16	51	-	100
2016/17	96	-	196
2017/18	152	-	348
2018/19	44	(58)	333
2019/20	-	(78)	255
2020/21	-	(78)	177
2021/22	-	(78)	99
2022/23	-	(78)	20
2023/24	-	(20)	-

b) The amounts deferred or the additions to the deferral account are calculated based on a percentage of actual revenues recorded. To the extent that revenues were impacted by weather, customer usage etc., the amounts deferred were also impacted.

REFERENCE:

Application Appendix 1 pg. 1; 2017/18 GRA MH-93

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the detail of "other expenses" incurred and forecast for the years 2017/18, 2018 /19 and 2019/20.

RESPONSE:

The following schedules provide the detail for other expenses for the 2017/18 actuals, 2018/19 Outlook and 2019/20 Interim Budget, as well as the detail for other expenses for the same years as per Exhibit #93 from the 2017/18 and 2018/19 GRA (MH16 Update with Interim Forecast).

The primary difference between 2017/18 and 2019/20 is mainly a result of the difference in the timing of the transfer of the $380 million Conawapa development costs from CWIP to a regulatory deferral account. The reduction in spending for the 2018/19 Outlook is primarily due to a reduction in planned DSM spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. It should be noted that amounts related to DSM, site restoration, regulatory and Conawapa costs are deferred and amortized in Net Movement and detailed explanations of changes for these amounts are found in the response to PUB/MH I-10.

MANITOBA HYDRO
OTHER EXPENSES
(000's)

	2017/18 Actual	2018/19 Outlook	2019/20 Interim Budget
Demand side management expenses	63 667	62 539	94 251
Site restoration	1 221	6 421	11 201
Regulatory costs	10 136	2 476	2 832
Discontinuance of Conawapa Generating Station development	379 204	-	-
Cost of services provided to external entities	448	250	250
Corporate restructuring costs	46 577	6 438	2 211
Miscellaneous	28	42	42
Total other expenses *	**$ 501 281**	**$ 78 167**	**$ 110 787**
Year over year $ change		$ (423 114)	$ 32 620
Year over year % change		-84.4%	41.7%

MH16 Update with Interim (Exhibit #93)	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast
Demand side management expenses	57 184	99 404	94 251
Site restoration	2 794	2 703	1 408
Regulatory costs	3 664	2 339	1 339
Discontinuance of Conawapa Generating Station development			379 758
Cost of services provided to external entities	2 200	2 200	2 200
Corporate Restructuring Costs	50 388	2 193	2 193
Miscellaneous	132	132	132
Total other expenses *	**$ 116 362**	**$ 108 970**	**$ 481 281**
Year over year $ change		$ (7 392)	$ 372 311
Year over year % change		-6.4%	341.7%

** Amounts related to Demand side management, site restoration, regulatory costs and the discontinuance of Conawapa Generating Station have been deferred and amortized in Net Movement*

REFERENCE:

Application Appendix 1 pg. 1; 2017/18 GRA MH-93

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the detail of "other expenses" incurred and forecast for the years 2017/18, 2018/19 and 2019/20.

RESPONSE:

The following schedules provide the detail for Other Expenses for the 2017/18 actuals, 2018/19 Current Outlook and 2019/20 Approved Budget, as well as the detail for Other Expenses for the same years as per Exhibit #93 from the 2017/18 and 2018/19 GRA (MH16 Update with Interim Forecast).

The difference between 2017/18 and 2019/20 is mainly a result of the difference in timing of the transfer of the $380 million Conawapa development costs from CWIP to a regulatory deferral account. The transfer in 2017/18 to a regulatory deferral account is in compliance with Directive 19 of Order 59/18. The reduction in spending for the 2018/19 Current Outlook is primarily due to a reduction in planned DSM spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. The reduction in the 2019/20 Approved Budget reflects the continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba. It should be noted that amounts related to DSM, site restoration, regulatory and Conawapa costs are deferred and amortized through the Net Movement account and detailed explanations of changes for these amounts are found in the response to PUB/MH I-10a-c (Updated).

MANITOBA HYDRO
OTHER EXPENSES
(000's)

Supplement to the 2019/20 Electric Rate Application	**2017/18 Actual**	**2018/19 Current Outlook**	**2019/20 Approved Budget**
Demand side management expenses	63 667	62 539	61 219
Site restoration	1 221	7 355	6 722
Regulatory costs	10 136	1 733	5 281
Discontinuance of Conawapa Generating Station development	379 204	-	-
Cost of services provided to external entities	448	612	350
Corporate restructuring costs	46 577	5 036	341
Claim settlement	-	1 480	-
Miscellaneous	28	37	36
Total other expenses *	**$ 501 281**	**$ 78 793**	**$ 73 949**
Year over year $ change		$ (422 488)	$ (4 843)
Year over year % change		-84.3%	-6.1%

MH16 Update with Interim (Exhibit #93)	**2017/18 Forecast**	**2018/19 Forecast**	**2019/20 Forecast**
Demand side management expenses	57 184	99 404	94 251
Site restoration	2 794	2 703	1 408
Regulatory costs	3 664	2 339	1 339
Discontinuance of Conawapa Generating Station development			379 758
Cost of services provided to external entities	2 200	2 200	2 200
Corporate Restructuring Costs	50 388	2 193	2 193
Miscellaneous	132	132	132
Total other expenses *	**$ 116 362**	**$ 108 970**	**$ 481 281**
Year over year $ change		$ (7 392)	$ 372 311
Year over year % change		-6.4%	341.7%

** Amounts related to Demand side management, site restoration, regulatory costs and the discontinuance of Conawapa Generating Station have been deferred and amortized in Net Movement*

REFERENCE:

Appendix 8, 2017/18 GRA Tab 6 Figure 6.4 Operating and Administrative Expense breakdown

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update Figure 6.14 from the 2017/18 GRA including actuals, and updated detailed forecast for 2017/18, 2018/19 and provide the compound annual growth by cost element from 2016/17 actual to 2018/19 forecast.
b) Update (a) and include the detail of 2019/20 Interim Budget OM&A expenditures by cost element and provide the compound annual growth from 2016/17 actual to 2019/20 forecast and explain all variances.

RESPONSE:

a) The following table provides an update to Figure 6.14 of the 2017/18 GRA to include actual expenditures for 2016/17 and 2017/18, the 2018/19 Outlook and the compound annual growth by cost element from 2016/17 to 2018/19. As discussed during the 2017/18 GRA, a detailed forecast for 2017/18 was not prepared, and therefore, cannot be provided, as the corporation was undergoing a restructuring program which affected the structure and responsibilities/accountabilities of the Corporate/Operating groups.

b)

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Outlook	Compound Annual Growth 2016/17-2018/19
Employee Related Expenditures						
Wages & salaries	$ 493 346	$ 506 811	$ 517 311	$ 493 691	$ 469 597	-4.7%
Overtime	69 541	67 982	72 256	75 095	76 642	3.0%
Employee benefits	166 854	159 363	165 924	156 884	145 225	-6.4%
Other	73 067	70 832	71 943	68 233	73 421	1.0%
Total Employee Related Expenditures	802,809	804,988	827,435	793,903	764,885	-3.9%
Less: Capitalized Labor & Overhead	(313 931)	(322 144)	(345 763)	(336 397)	(332 292)	-2.0%
Operational Employee Related Expenditures	488 877	482 844	481 672	457 507	432 593	-5.2%
External services and materials	126 850	127 711	126 024	122 843	130 905	1.9%
Donations, sponsorships & grants	2 804	2 592	2 134	2 434	2 140	0.2%
Uncollectible accounts	4 890	5 748	4 266	12 375	4 265	0.0%
Other	452	6 215	2 820	1 200	9 188	80.5%
Cost recoveries	(15 115)	(15 789)	(15 706)	(16 387)	(14 593)	-3.6%
O&A charged to gas operations	(70 355)	(66 607)	(65 384)	(63 112)	(63 315)	-1.6%
Operating and Administrative expenses	$ 538 404	$ 542 714	$ 535 825	$ 516 859	$ 501 183	-3.30%

It is noted that the compound annual growth of 80.5% in the Other line item in the above table is primarily due to funds for transitional business requirements as a result of the voluntary departure program included in the 2018/19 Outlook.

c) The 2019/20 Interim Budget of $511.1 million reflects an inflationary increase of 2% over the 2018/19 Outlook, which is aligned with the Manitoba Consumer Price Index. The details underlying each line item included in the 2019/20 Interim Budget are not available. Following Provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 Interim Budget.

The following table provides an annual summary of Operating and Administrative actual expenditures from 2014/15 through 2017/18, the 2018/19 Outlook and the 2019/20

Interim Budget. The compound annual growth from 2016/17 to 2019/20 is a decrease of -1.6%, primarily due to the reduction in Manitoba Hydro's workforce.

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Outlook	Compound Annual Growth 2016/17-2018/19	2019/20 Interim Budget	Compound Annual Growth 2016/17-2019/20
Operating and Administrative expenses	$ 538 404	$ 542 714	$ 535 825	$ 516 859	$ 501 183	-3.30%	$ 511 100	-1.60%

REFERENCE:

Appendix 8, pg. 6 of 6

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a schedule detailing the forecast for OM&A for 2018/19 by quarter (Q3 & Q4) for the year and the total forecast for the end of the 2018/19 outlook year.
b) Provide detailed breakdowns by cost element and business unit of the OM&A budgets for 2018/9 and 2019/20 Interim Budget.
c) Provide detail of Other Employee related expenditures
d) Provide details of the external service and material by cost element.
e) Provide details of the capitalized labour, overtime and benefits, and overhead by year.

RESPONSE:

a) The following table provides the 2018/19 year-to-date forecast by quarter

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	June 2018	September 2018	December 2018	March 2019	2018/19 Outlook
Employee Related Expenditures					
Wages & salaries	$ 116 922	$ 235 672	$ 353 226	$ 469 597	$ 469 597
Overtime	21 069	39 423	58 912	76 642	76 642
Employee benefits	38 877	71 778	104 098	145 225	145 225
Other	18 275	36 345	54 691	73 421	73 421
Total Employee Related Expenditures	195 142	383 218	570 927	764 885	764 885
Less: Capitalized Labor & Overhead	(83 837)	(167 570)	(245 559)	(332 292)	(332 292)
Operational Employee Related Expenditures	111 305	215 649	325 368	432 593	432 593
External services and materials	32 227	65 038	97 279	130 905	130 905
Donations, sponsorships & grants	535	1 070	1 605	2 140	2 140
Uncollectible accounts	1 066	2 133	3 199	4 265	4 265
Other	2 005	4 399	6 794	9 188	9 188
Cost recoveries	(3 648)	(7 296)	(10 944)	(14 593)	(14 593)
O&A charged to gas operations	(16 088)	(31 676)	(47 251)	(63 315)	(63 315)
Operating & Administrative Expenses	$ 127 402	$ 249 317	$ 376 050	$ 501 183	$ 501 183

*Reflects the cumulative Year-to-Date Forecast by quarter; March 2019 reflects the Annual 2018/19 O&A Forecast

b) The details underlying each line item included in the 2019/20 Interim Budget are not available. Following Provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 Interim Budget.

The following tables provide a more detailed breakdown by cost element (compared to the table provided in response to part a) as well as a breakdown by Corporate/Operating group for the 2018/19 Forecast Year.

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	2018/19 Outlook
Employee Related Expenditures	
Wages & salaries	$ 469 597
Overtime	76 642
Employee benefits	145 225
Employee training & safety	4 294
Travel expenses	30 545
Motor vehicles	29 870
Office expenses	8 712
Other	73 421
Total Employee Related Expenditures	764 885
Less: Capital activities	(312 992)
Less: Capitalized overhead	(19 300)
Less: Capitalized Labor & Overhead	(332 292)
Operational Employee Related Expenditures	432 593
Materials & tools	25 752
Consulting & professional fees	17 071
Construction & maintenance services	18 439
Building & property costs	29 656
Equipment maintenance & rentals	19 691
Consumer services	5 272
Customer & public relations	2 178
Sponsored memberships	1 714
Computer services	1 151
Communication systems	1 861
Research & development costs	2 029
Administrative services	6 091
External services and materials	130 905
Donations, sponsorships & grants	2 140
Uncollectible accounts	4 265
Miscellaneous expense	5
Contingency & planning	9 183
Other	9 188
Corporate recoveries	(463)
Operating expense recovery	(14 130)
Cost recoveries	(14 593)
O&A charged to gas operations	(63 315)
Operating & Administrative Expenses	$ 501 183

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY CORPORATE/OPERATING GROUP
(000's)

		2018/19 Outlook
President & CEO	$	4 141
General Counsel & Corporate Secretary		3 546
Human Resource & Corporate Services		106 045
Indigenous Relations		6 084
Finance & Strategy		23 597
Generation & Wholesale		138 151
Transmission		144 539
Marketing & Customer Service		182 188
Corporate/Operating Group	**$**	**608 290**
Capitalized Overhead		(19 300)
Corporate Allocations & Adjustments		(24 491)
Operating & Administration Charged to Centra		(63 315)
O&A Costs Attributable to Electric Operations	**$**	**501 183**

c) The following table provides a breakdown of 2018/19 Other Employee Related Expenditures. As noted in the response to part b), the details underlying this line item included in the 2019/20 Interim Budget are not available.

MANITOBA HYDRO
OTHER EMPLOYEE RELATED EXPENDITURES
(000's)

	2018/19 Outlook
Employee Related Expenditures	
Employee training & safety	4 294
Travel expenses	30 545
Motor vehicles	29 870
Office expenses	8 712
Other	73 421

d) The following table provides a breakdown of 2018/19 External services and materials. As noted in the response to part b), the details underlying this line item included in the 2019/20 Interim Budget are not available.

MANITOBA HYDRO
EXTERNAL SERVICES AND MATERIALS
(000's)

	2018/19 Outlook
Materials & tools	25 752
Consulting & professional fees	17 071
Construction & maintenance services	18 439
Building & property costs	29 656
Equipment maintenance & rentals	19 691
Consumer services	5 272
Customer & public relations	2 178
Sponsored memberships	1 714
Computer services	1 151
Communication systems	1 861
Research & development costs	2 029
Administrative services	6 091
External services and materials	130 905

e) The following table provides a breakdown of 2018/19 Capitalized Labor and Overhead. The straight time and overtime activity rates calculated to capitalize labour include benefit costs, and as such, benefit costs cannot be segregated from straight time and overtime capital activities.

As noted in the response to part b), the details underlying this line item included in the 2019/20 Interim Budget are not available

MANITOBA HYDRO
CAPITALIZED LABOR & OVERHEAD
(000's)

	2018/19 Forecast
Less: Capital straight time activities	(253 986)
Less: Capital overtime activities	(59 006)
Less: Capitalized overhead	(19 300)
Less: Capitalized Labor & Overhead	(332 292)

REFERENCE:

Application Appendix 8

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the quarterly OM&A Report for the 3rd quarter of 2018/19 when available.

RESPONSE:

Please see the attached for Manitoba Hydro's Quarterly Report on Operating & Administrative Expenses for the quarter ended December 31 which was filed with the PUB on February 14, 2019 in accordance with Directive 14 of Order 73/15.

RESPONSE TO DIRECTIVE #14 – BOARD ORDER 73/15

For the Quarter Ended December 31, 2018

14. *Manitoba Hydro shall file quarterly updates regarding its Operation, Maintenance & Administration (OM&A) expenditures and the actual OM&A expenditures compared to Manitoba Hydro's target.*

Manitoba Hydro's Operating and Administrative (O&A) expenses for Electric Operations for the third quarter of 2018/19 were $378.0 million, as compared to a forecast of $376.1 million. The 0.5% variance continues to be attributable to higher employee related expenditures primarily due to lower than anticipated capitalization of resources, partially offset by unallocated contingency funds for transitional requirements which may be required as a result of the Voluntary Departure Program (VDP), as well as the timing of consulting and professional fee requirements.

Compared to the same 9 month period last year, O&A expenditures were lower by $10.9 million or 2.9%. The decrease is primarily related to a reduction in employee related expenditures as a result of the VDP. This was partially offset by an increase in external services and materials primarily due to unscheduled maintenance requirements, as well as externally contracted training for Bipole III converter station equipment and the Enterprise Asset Management system. In addition, there was an increase in biophysical monitoring requirements for Wuskwatim and an environmental investigation at Sutherland.

A summary of Manitoba Hydro's actual and forecast O&A expenditures by cost element with a comparison to the 2017/18 third quarter expenditures has been provided in the table below, as well as the annual O&A forecast for 2018/19.

ELECTRIC OPERATIONS
OPERATING & ADMINISTRATIVE COSTS BY COST ELEMENT
FOR THE QUARTER ENDED DECEMBER 31, 2018

(in Thousands of Dollars)

	2017/18 Q3 Actual	2018/19 Annual Forecast	2018/19 Q3 Actual	2018/19 Q3 Forecast	Favourable (Unfavourable) Variance
Employee Related Expenditures					
Wages & salaries	$377 247	$469 597	$345 088	$353 226	$8 138
Overtime	58 024	76 642	55 503	58 912	3 409
Employee benefits	117 879	145 225	105 703	104 098	(1 605)
Other	50 065	73 421	51 781	54 691	2 910
Total Employee Related Expenditures	603 215	764 885	558 075	570 927	12 852
Less: Capitalized labour and overhead	(248 096)	(332 292)	(221 505)	(245 559)	(24 054)
Operational Employee Related Expenditures	355 119	432 593	336 570	325 368	(11 202)
External services and materials	89 489	130 905	94 104	97 279	3 175
Donations, sponsorships & grants	1 702	2 140	1 408	1 605	197
Uncollectible accounts	3 279	4 265	3 214	3 199	(15)
Other	557	9 188	1 731	6 794	5 063
Cost recoveries	(11 666)	(14 593)	(12 188)	(10 944)	1 244
O&A charged to gas operations	(49 545)	(63 315)	(46 814)	(47 251)	(437)
Operating & Administrative Expenses	**388 935**	**501 183**	**378 025**	**376 050**	**(1 975)**

REFERENCE:

Application Appendix 8, pg. 6

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a comparison between OM&A by cost element and business unit for the forecast for 2019/20 with the forecast for 2018/19 and explain the variances.

RESPONSE:

The details underlying each line item included in the 2019/20 interim budget are not available. Following provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application following approval of Manitoba Hydro's next Integrated Financial Forecast. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 interim budget.

REFERENCE:

Application Appendix 3 pg 9 of 110

PREAMBLE TO IR (IF ANY):

On page 9 of the Annual Report the Corporation states: *Further opportunities are being developed to reduce our operating and maintenance costs – most recently through our Strategic Sourcing Initiative. Annually, we spend approximately $750 million procuring goods and services for our operations – through strategic procurement initiatives we estimate annual recurring savings of $36 million will be realized over the next three years. This approach is an acceleration of the work already begun in our Supply Chain Management Performance Enhancement Program initiated in 2015, which has resulted in accumulated realized savings totaling approximately $22 million to the end of this fiscal year.*

QUESTION:

a) Provide details on the $22 million in saving that were realized in 2017/18 related to the Supply Chain Management Performance Enhancement Program.

b) Provide a schedule detailing the forecast savings of $36 million by year and indicate to what extent these savings are incorporated in the electric operations forecast for 2018/19 and 2019/20. Please provide detailed narrative explanation of the savings to be realized.

RESPONSE:

a) The following table outlines the savings achieved by Category. These savings include a mix of one-time and ongoing annual savings. They are also a mix of savings from both operating and capital expenditures, including those incurred on major capital projects such as Bipole III and Keeyask.

	Realized Savings by Category (in thousands of dollars)			
	FY2014/15	FY2015/16	FY2016/17	FY2017/18
Building, Facility, Construction and Maintenance Services & Goods	$17	$958	$5,321	$270
Information Technology and Communication	0	3	90	251
Infrastructure Equipment and Core Components	0	513	2,866	4,897
Logistics, Transport & Fleet	0	548	1,393	514
Maintenance, Repair, Operations (MRO) Goods	1,471	511	291	447
Management and Business Professionals and Administrative Services	0	0	4	10
Travel, Hospitality and Catering	153	555	605	549
Total Annual Realized Savings	**$1,642**	**$3,087**	**$10,569**	**$6,938**
Cumulative Savings	**$1,642**	**$4,729**	**$15,298**	**$22,236**

b) The table below outlines the forecasted annual recurring savings. Sourcing strategies have been completed for the first three waves of initiatives. An additional two waves of initiatives have also been identified; however sourcing strategies for these two waves are still being assessed and will require further development. Upon completion the savings will be further refined and timelines will be estimated. The table below outlines the preliminary estimates by category.

	Estimated Savings by Category		
	FY2018/19	FY2019/20	Future
Building, Facility, Construction and Maintenance Services & Goods	$1,750	$2,149	$7,079
Information Technology and Communication	1,500	1,500	2,000
Infrastructure Equipment and Core Components	3,586	3,586	5,086
Logistics, Transport & Fleet	444	1,544	4,964
Maintenance, Repair, Operations (MRO) Goods	1,297	3,772	6,347
Management and Business Professionals and Administrative Services	200	1,600	6,000
Software Maintenance & Support			1,500
Travel, Hospitality and Catering	720	720	1,510
Building and facility construction, maintenance and repair services			1,400
Total Annual Estimated Savings	**$9,497**	**$14,871**	**$35,886**

The estimated savings relate to commodities/services for which Manitoba Hydro purchases annually and which may be used by both operating and capital projects. The savings are calculated at the contract level with the reduction in costs assisting Manitoba Hydro in meeting its budgets.

There are a number of sourcing strategies that are undertaken to drive cost savings, including amalgamating contracts, standardizing purchases, rationalizing suppliers and volume discounts. In addition to hard savings, a number of efficiencies and other soft benefits are realized through the strategic sourcing initiatives. This includes management/ administrative time savings as a result of contract consolidation, as well as process improvement initiatives to reduce the administrative burden/ create process efficiencies related to work flow and information management.

REFERENCE:

Appendix 8 pg 2 & 6

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide details of OM&A for external Services and Materials for each of the years 2016/17, 2017/18 and that forecast for 2018/19 and 2019/20
b) Provide an explanation of why MH is forecasting an increase of over $8 million or 6.5% in 2018/19 from 2017/18.in external services and materials.

RESPONSE:

a) The details underlying each line item included in the 2019/20 Interim Budget are not available. Following Provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 interim budget.

   The following table provides additional cost element details for External services and materials for 2016/17, 2017/18 and 2018/19.

MANITOBA HYDRO
EXTERNAL SERVICES AND MATERIALS
(000's)

	2016/17 Actual	2017/18 Actual	2018/19 Forecast
Materials & tools	25 389	24 451	25 752
Consulting & professional fees	15 840	10 746	17 071
Construction & maintenance services	16 821	18 904	18 439
Building & property costs	29 039	30 211	29 656
Equipment maintenance & rentals	18 734	19 142	19 691
Consumer services	5 236	5 452	5 272
Customer & public relations	2 227	1 716	2 178
Sponsored memberships	1 677	1 651	1 714
Computer services	967	817	1 151
Communication systems	1 668	1 699	1 861
Research & development costs	2 355	1 985	2 029
Administrative services	6 071	6 068	6 091
External services and materials	**$ 126 024**	**$ 122 843**	**$ 130 905**

b) The majority of the increase in the 2018/19 forecast is primarily in consulting and professional fees. The 2017/18 expenditures reflect a significantly lower level of costs as a result of the completion of various initiatives in the prior year such as the strategic initiative funding program as well as other work including Wuskwatim aquatic monitoring, interconnection studies, power sale negotiations and arc flash studies. In addition, new initiatives were delayed as a result of the corporate restructuring initiative. The 2018/19 forecast reflects committed engagements as well as a new requirement for environmental monitoring for the Bipole III transmission line following its in-service in July of 2018.

REFERENCE:

Application pg. 29, PUB/MH II-27 a-b (2017/18 & 2018/19 GRA)

PREAMBLE TO IR (IF ANY):

A total of 821 employees were approved under the VDP with the majority of staff departing by March 2018. Manitoba Hydro's headcount as of April 2017, excluding summer students and was approximately 6150. The Corporation's projected headcount to March 2020 is approximately 5250.

QUESTION:

a) Please provide a schedule detailing the staffing compliment by business unit for each of the years 2016/17 through 2019/20.
b) Please provide an update to PUB/MH II-27 a & b including 2017/18 actual and forecast for 2018/19 and 2019/20.

RESPONSE:

The details underlying each line item included in the 2019/20 Interim Budget are not available. Following Provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 Interim Budget.

It is noted that the information referenced in the preamble refers to headcount which is calculated based on the number of employees excluding seasonal staff, regardless of the employees' work schedule (full time or part time). An EFT is calculated based on hours worked (*on an annual basis 1 916 hours equates to 1 EFT*) for all staff and as such will differ from headcount information. The responses below provide information on number of EFTs rather than headcount.

a) The following table provides the straight time EFTs by Corporate/Operating group for 2016/17 through 2018/19.

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2016/17 Actual	2017/18 Actual	2018/19 Forecast
President & CEO	14	10	9
General Counsel & Corporate Secretary	26	24	23
Human Resources & Corporate Services	780	725	669
Indigenous Relations	86	80	79
Finance & Strategy	163	141	133
Generation & Wholesale	1 268	1 186	1 103
Transmission	1 665	1 557	1 475
Marketing & Customer Service	2 204	2 055	1 949
	6 206	**5 778**	**5 440**

b) Please see the table below which has been updated to include actual results for 2017/18 and forecast for 2018/19.

Fiscal Year	Wages & Salaries	Overtime	Employee Benefits	Total	Total EFTs*
Actual					
2004/05	$ 319 353	$ 33 822	$ 76 628	$ 429 804	5 870
2005/06	$ 330 834	$ 37 993	$ 79 188	$ 448 015	5 978
2006/07	$ 343 271	$ 38 869	$ 82 162	$ 464 302	5 988
2007/08	$ 357 690	$ 41 709	$ 85 865	$ 485 263	6 071
2008/09	$ 376 985	$ 45 447	$ 90 858	$ 513 290	6 276
2009/10	$ 404 576	$ 50 646	$ 97 226	$ 552 448	6 429
2010/11	$ 422 240	$ 50 655	$ 101 391	$ 574 286	6 594
2011/12	$ 448 032	$ 54 936	$ 107 247	$ 610 214	6 608
2012/13	$ 464 158	$ 60 953	$ 143 889	$ 668 999	6 678
2013/14	$ 476 693	$ 62 284	$ 161 336	$ 700 312	6 756
2014/15	$ 490 004	$ 69 442	$ 171 134	$ 730 580	6 713
2015/16	$ 503 509	$ 67 928	$ 175 801	$ 747 238	6 610
2016/17	$ 513 627	$ 72 206	$ 179 552	$ 765 385	6 599
2017/18	$ 490 835	$ 75 037	$ 170 870	$ 736 741	6 168
Forecast					
2018/19	$ 466 896	$ 76 588	$ 164 302	$ 707 786	5 878

*Includes straight time and overtime EFTs.

The following table has been updated to include actual straight time capital construction EFTs for 2017/18 and forecast straight time capital construction EFTs for 2018/19.

MANITOBA HYDRO
STRAIGHT TIME CAPITAL CONSTRUCTION EFTs

	Actuals																			
	2012/13				2013/14				2014/15				2015/16				2016/17			
	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM
President & CEO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Counsel & Corporate Secretary	1	4	0	0	0	9	0	0	1	3	0	0	1	1	0	0	0	1	0	0
Human Resources & Corporate Services	85	36	0	2	84	41	0	1	95	55	0	1	92	48	0	2	89	43	0	3
Indigenous Relations	0	24	28	0	0	28	26	0	1	23	29	0	2	16	29	0	1	15	34	0
Finance & Strategy	1	2	0	0	1	7	0	0	1	2	0	1	2	0	0	0	3	0	0	0
Generation & Wholesale	161	284	2	0	186	292	3	0	211	236	5	1	189	244	4	0	162	273	8	0
Transmission	353	205	1	0	363	212	0	0	414	287	0	0	399	296	0	1	378	382	1	1
Marketing & Customer Service	654	23	3	74	701	24	2	76	699	20	0	80	770	18	2	92	790	11	1	106
Total Corporation	1254	579	34	76	1335	612	32	78	1423	626	34	83	1456	623	36	96	1423	724	44	110

MANITOBA HYDRO
STRAIGHT TIME CAPITAL CONSTRUCTION EFTs

	Actuals				Forecast			
	2017/18				2018/19			
	Sustaining	MNG&T	Mitigation	DSM	Sustaining	MNG&T	Mitigation	DSM
President & CEO	0	0	0	0	0	0	0	0
General Counsel & Corporate Secretary	0	1	0	0	0	1	0	0
Human Resources & Corporate Services	80	33	0	2	85	38	0	2
Indigenous Relations	0	12	30	0	1	16	25	0
Finance & Strategy	2	0	0	0	2	1	0	0
Generation & Wholesale	156	270	14	0	171	251	6	0
Transmission	331	394	0	1	389	308	0	1
Marketing & Customer Service	742	5	1	88	702	17	1	79
Total Corporation	1311	716	46	92	1350	633	32	82

REFERENCE:

Application pg. 28; 2015/16 Interim Application Section 6 pg. 48; Order 59/18 pg. 142

PREAMBLE TO IR (IF ANY):

QUESTION:

Explain why Manitoba Hydro is now targeting 2% growth in O&A expense, compared to the previous target of 1% articulated in MH15/16 Interim Application Section 6 pg. 48

RESPONSE:

The MH15 forecast filed in Manitoba Hydro's April 1, 2016 Interim Application assumed a 1% growth factor through to 2021/22 excluding the impacts of accounting changes and incremental operating costs in years where major new generation & transmission comes into service. This plan was replaced with initiatives designed to advance the O&A savings, incorporating significant staff reductions. Manitoba Hydro successfully completed the Committed Position Reduction program by March 2017, achieving a total reduction of 429 compared to the commitment of 300 positions. In addition, the corporation launched the Voluntary Departure Program (VDP) in April 2017. The VDP resulted in a further reduction of 821 staff over the 2017/18 and 2018/19 fiscal years. These initiatives resulted in a total staff reduction of 1,250, the majority of which were not known at the time of the April 1, 2016 Interim Application and has resulted in a significant decrease in overall O&A costs as compared to the April 1, 2016 Interim Application as per the table below. Expenditures for both 2018/19 and 2019/20 are expected to be lower than forecasted in the April 1, 2016 Interim Application by $70 million and $74 million respectively.

Given the advancement of significant staffing reductions and associated savings, Manitoba Hydro is limiting the increase in O&A expenditures for 2019/20 to align with Manitoba Consumer Price Index of 2% as it is not sustainable to maintain a 1% growth factor given negotiated contract wage settlements and cost escalation for material and services.

MANITOBA HYDRO
OPERATING & ADMINISTRATIVE EXPENSE
(in millions $'s)

	2016/17			2017/18			2018/19			2019/20		
	MH15	Actual	Inc/(Dec)	MH15	Actual	Inc/(Dec)	MH15	Outlook	Inc/(Dec)	MH15	Interim Budget	Inc/(Dec)
Operating and Administrative	552	536	(16)	557	517	(40)	571	501	(70)	585	511	(74)

REFERENCE:

2017/18 GRA PUB/MH II-6b

PREAMBLE TO IR (IF ANY):

In PUB/MH II-6b, the table provided information by Corporate/Operating group reflecting the organization structure as of April 2017 relating to employees leaving Manitoba Hydro through the VDP program, including the number of employees departing, their current annual salary and a benefit provision. The total savings related to the VDP were then forecast to be $91.9 million annually.

QUESTION:

a) Provide the details of all VDP expenditures
b) Provide the details of all OM&A savings achieved as a result of the VDP, and an explanation as to whether the $92 million in savings has been achieved and if not, why those savings have not been achieved.

RESPONSE:

a) The following table provides a summary of the expenditures incurred for the Voluntary Departure Program in 2017/18 and up to September 2018 of 2018/19, followed by a description of each of the components listed in the table. Minor expenditures are anticipated for the balance of 2018/19 and in early 2019/20.

VDP Expenditures
in thousands of dollars

	2017/18	YTD 30-Sep-18	Cumulative Total
VDP wages & salaries	39 683	504	40 187
VDP benefit allocation	2 976	2 348	5 324
VDP internal costs	226	-	226
Total	**42 885**	**2 852**	**45 737**

- VDP wages & salaries includes the approved VDP payout (bi-weekly salary of an employee multiplied by weeks of service, to a maximum of 30 weeks) as well as current year vacation payouts, where applicable.
- VDP benefit allocation includes an estimate of benefit costs (35% of wage and salary payments) for employees who chose leave with pay instead of a lump sum payment to recognize that staff on leave are eligible for benefit reimbursement (e.g. dental, vision, etc).
- VDP internal costs include incremental overtime costs for staff involved in the administration of the VDP.

b) $92.6 million reflects the total annual employee-related cost savings to be achieved following the departure of all approved applicants. The table below provides an update to the table provided in the response to PUB/MH II-6b of the 2017/18 GRA to include employees seconded to subsidiary operations which were discussed but not previously included in the table. The table reflects the headcount, annual salary and benefit provision as of April 2017 for all employees approved under the VDP by Corporate/ Operating group.

VOLUNTARY DEPARTURE PROGRAM
($ in millions)

	Headcount	Annual Salary	Benefits	Total
President & CEO	1	$ 0.1	$ 0.0	$ 0.1
General Counsel & Corporate Secretary	5	0.6	0.2	0.8
Human Resources & Corporate Services	147	12.3	4.3	16.6
Indigenous Relations	9	0.7	0.2	0.9
Finance & Strategy	33	3.0	1.1	4.1
Generation & Wholesale	157	13.9	4.9	18.8
Transmission	198	16.7	5.8	22.5
Marketing & Customer Service	267	20.8	7.3	28.1
Subsidiary Secondments	4	0.5	0.2	0.6
Total	821	$ 68.6	$ 24.0	$ 92.6

Staff approved under the VDP worked in all functions of the business impacting both capital construction and operations and maintenance work, as a result, the projected annual savings of $92.6 million represent a gross saving (before capitalization) for the corporation. Employee departure dates for approved applicants ranged from June 2017 through January 2019, with 96% of VDP employees having departed the corporation by the end of January 2018. As a result, 2019/20 will be the first year to reflect the full projected annual savings.

REFERENCE:

Application Appendix 3 pg. 9

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide the number of employees that departed under the VDP by fiscal year
b) Provide the number of former employees that departed under the VDP who have been retained by Manitoba Hydro as Independent Contractors or to provide any services or work to Manitoba Hydro.
c) With reference to the response to item (b), quantify the cost per fiscal year for the former employees that departed under the VDP who have been retained by Manitoba Hydro following their departure under the VDP.

RESPONSE:

a) The following table provides the number of employees that departed the corporation under the VDP by the fiscal year of departure.

Voluntary Departure Program
Employee Departures by Fiscal Year

	2017/18	**2018/19**
Number of employees departing	795	26

b) There are four Manitoba Hydro employees that departed under the VDP who have been retained by Manitoba Hydro as Independent Contractors or to provide services or work to Manitoba Hydro.

c) The total cost for the services provided through the contracts noted above in part (b) is approximately $163,000 in fiscal year 2017/18 and approximately $387,000 to date in fiscal year 2018/19.

REFERENCE:

PUB/MH I-11 b (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide EFT staffing level information for the last five fiscal years and that forecast through the 2019/20 test year by business unit. Please detail the voluntary departure take-up and the position reductions prior to the voluntary departure program.
b) Indicate to what extent the employee composition for the years are assigned to capital construction, operations and governance, support and services.

RESPONSE:

The details underlying each line item included in the 2019/20 Interim Budget are not available. Following Provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 Interim Budget.

a) The table below provides the straight time EFTs for the last five fiscal years, from 2013/14 through 2017/18, as well as the budget for 2018/19 by Corporate/Operating group.

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Budget
President & CEO	14	15	14	14	10	9
General Counsel & Corporate Secretary	27	25	27	26	24	23
Human Resources & Corporate Services	823	805	792	780	725	669
Indigenous Relations	99	99	89	86	80	79
Finance & Strategy	176	171	166	163	141	133
Generation & Wholesale	1 470	1 334	1 286	1 268	1 186	1 103
Transmission	1 575	1 669	1 663	1 665	1 557	1 475
Marketing & Customer Service	2 190	2 169	2 189	2 204	2 055	1 949
	6 374	**6 287**	**6 226**	**6 206**	**5 778**	**5 440**

The following table provides a summary by Operating/Corporate group of the 1250 position reductions to be achieved by the end of 2018/19. These reductions have been achieved under two separate initiatives:

- The Committed Position Reduction program which was complete at the end of 2016/17 and achieved a reduction of 429 positions as compared to a commitment of 300;
- The Voluntary Departure Program – initiated in early 2017 with the majority of the 821 approved staff departures occurring before February, 2018.

MANITOBA HYDRO
POSITION REDUCTIONS

	Committed Position Reduction Plan				Voluntary Departure Plan			
	2014/15 Actual	2015/16 Actual	2016/17 Actual	Plan Total	2017/18 Actual	2018/19 Budget	Plan Total	Grand Total
President & CEO	2	1	1	4	1	-	1	5
General Counsel & Corporate Secretary	2	-	-	2	5	-	5	7
Human Resources & Corporate Services	53	23	1	77	143	4	147	224
Indigenous Relations	8	2	-	10	9	-	9	19
Finance & Strategy	6	6	1	13	33	-	33	46
Generation & Wholesale	42	50	13	105	146	11	157	262
Transmission	49	65	1	115	187	11	198	313
Marketing & Customer Service	70	21	12	103	267	-	267	370
Subsidiaries	-	-	-	-	4	-	4	4
	232	**168**	**29**	**429**	**795**	**26**	**821**	**1 250**

The position reductions in the table above have occurred at various points throughout each fiscal year and are therefore are not equivalent to an annualized EFT. An EFT is a calculated statistic based on hours worked (*on an annual basis 1 916 equates to 1 EFT*) and as such, will differ from position reductions.

b) The table below provides a breakdown of the straight time EFTs provided in part a) above by capital construction, operations & maintenance and support and governance.

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Budget
Capital Construction	2 059	2 166	2 211	2 302	2 165	2 097
Operations & Maintenance	2 731	2 700	2 575	2 513	2 332	2 143
Support & Governance	1 584	1 421	1 440	1 391	1 281	1 200
Total Corporation	**6 374**	**6 287**	**6 226**	**6 206**	**5 778**	**5 440**

REFERENCE:

Application Appendix 8 pg. 2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide an explanation as to why actual bad debt expense increased by $8.1 million in 2017/18.
b) Provide a breakdown of the cost recoveries made.
c) Provide the bad debt expense policy.

RESPONSE:

a) While the Corporation continues to actively pursue collection of all outstanding arrears, bad debt expense increased $8.1 million as a result of an assessment of collectability of arrears. As arrears age and other circumstances change, the probability of collection on past due accounts may also change. As the probability of collection decreases, an allowance for doubtful accounts must be established. This is not a reflection of a write-off of accounts, but rather an estimate of accounts that may not be collected.

b) The following table provides a breakdown of the components of Cost Recoveries included in Operating & Administrative expenses.

MANITOBA HYDRO
COST RECOVERIES
(000's)

	2017/18 Actual
Intercompany Recoveries	(6 565)
Staffhouse Recoveries	(6 203)
Wage Recoveries	(1 157)
Parking Recoveries	(1 067)
Corporate Housing Recoveries	(873)
Other	(522)
Total Cost Recoveries	**(16 387)**

c) Manitoba Hydro does not have a bad debt expense policy; however, it follows a general practice in the collection of bad debts. Manitoba Hydro will pursue internal collections efforts for all outstanding receivables and continues to do so while a customer maintains an active account. When an account becomes inactive, i.e. the customer no longer has service with Manitoba Hydro, efforts are made to collect on the outstanding receivable in a timely manner. If no monies are received or a customer cannot be located, Manitoba Hydro will place the account with a third-party collection agency. The timeframe can vary before an account is placed with a third-party; however, generally it is done 60 days after the final bill becomes due. Once an account is placed with a third-party collection agency, Manitoba Hydro segregates the outstanding balance into its doubtful category. Manitoba Hydro's general practice is for inactive accounts to remain in this status for approximately one year before being written-off as part of the Corporation's year-end accounting procedures. The doubtful category also includes some active accounts where the probability of collection is deemed to be low. The extent to which active account balances may be included in this category is evaluated each year, and these amounts are not moved mechanistically to write-off in the following year.

Regardless of an account's status (active, inactive, doubtful or written-off), Manitoba Hydro endeavors to collect amounts owed to it. Amounts collected on accounts that are deemed either doubtful or written-off are deducted from the current year's bad debt expense.

REFERENCE:

2017/18 GRA PUB/MH I-18 and Figure 6.18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) File a comparison of the Depreciation and Amortization expense detail for 2017/18 actual and forecast for 2018/19 and 2019/20 with that forecast at the 2017/18 GRA and explain the changes.
b) Provide details on the loss on disposition of $8.588 million in 2017/18.

RESPONSE:

a) Please see the table below for a comparison of the Depreciation and Amortization expense detail for the years 2017/18 actual, 2018/19 Outlook and 2019/20 Interim Budget with the MH16 Update with Interim forecast as used in the 2017/18 GRA. Explanations of the differences are provided below.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
ELG rates (no net salvage)

(in thousands)	2017/18 Actual	2018/19 Outlook	2019/20 Interim Budget	2017/18 & 2018/19 MH16 Update with Interim * 2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	Increase/ (Decrease) 2017/18 Difference	2018/19 Difference	2019/20 Difference
PROPERTY, PLANT & EQUIPMENT									
Generation									
Hydraulic Generating Stations	115 675	118 291	120 540	116 110	118 481	122 332	(435)	(190)	(1 792)
Thermal Generating Stations	15 596	15 818	15 911	15 608	15 825	15 872	(12)	(7)	39
Diesel Generating Stations	2 079	2 029	1 986	2 037	2 049	2 009	42	(20)	(23)
	$ 133 350	$ 136 138	$ 138 437	$ 133 755	$ 136 355	$ 140 214	$ (405)	$ (217)	$ (1 777)
Transmission									
Transmission	14 203	35 682	42 130	14 470	32 051	41 049	(267)	3 630	1 081
	$ 14 203	$ 35 682	$ 42 130	$ 14 470	$ 32 051	$ 41 049	$ (267)	$ 3 630	$ 1 081
Stations									
Substations	92 264	138 197	158 126	91 853	137 349	161 763	412	848	(3 637)
Transformers	1 776	1 784	1 896	1 543	1 677	1 682	233	107	214
	$ 94 040	$ 139 981	$ 160 022	$ 93 396	$ 139 026	$ 163 445	$ 644	$ 955	$ (3 423)
Distribution									
Subtransmission Lines	7 308	7 642	7 988	7 461	7 854	8 257	(152)	(212)	(269)
Distribution Lines	61 053	65 651	68 785	62 940	65 970	69 633	(1 887)	(318)	(849)
Meters & Transformers	5 884	5 853	5 843	6 022	6 030	6 091	(138)	(177)	(248)
	$ 74 245	$ 79 146	$ 82 616	$ 76 423	$ 79 854	$ 83 981	$ (2 178)	$ (708)	$ (1 366)
Other									
Communications	20 203	22 328	23 169	20 240	22 972	24 437	(37)	(644)	(1 268)
Motor Vehicles	12 040	13 001	13 589	12 395	13 614	14 364	(355)	(613)	(776)
Structures & Improvements	9 916	10 078	10 277	10 061	10 110	10 331	(144)	(33)	(54)
General Equipment	16 984	16 866	16 596	16 945	16 894	17 318	39	(29)	(722)
Miscellaneous	(3 555)	(3 650)	(3 683)	(3 557)	(3 570)	(3 646)	2	(80)	(37)
Corporate Allocation	(1 371)	(1 372)	(1 372)	(1 371)	(1 371)	(1 372)	-	(1)	-
	$ 54 217	$ 57 251	$ 58 576	$ 54 712	$ 58 649	$ 61 432	$ (495)	$ (1 398)	$ (2 856)
							-	-	-
Total Depreciation on PP & E	**$ 370 055**	**$ 448 198**	**$ 481 781**	**$ 372 756**	**$ 445 935**	**$ 490 121**	**$ (2 701)**	**$ 2 264**	**$ (8 340)**
							-	-	-
INTANGIBLES							-	-	-
Computer Development	21 388	22 733	24 078	21 650	23 105	23 190	(262)	(372)	888
Easements	1 894	2 255	2 334	1 713	1 882	2 092	181	373	242
Total Amortization on Intangibles	**$ 23 282**	**$ 24 988**	**$ 26 412**	**$ 23 364**	**$ 24 987**	**$ 25 282**	**$ (82)**	**$ 1**	**$ 1 129**
							-	-	-
Loss on Disposition	8 588	-	-	-	-	-	8 588	-	-
Total Loss on Disposition	**$ 8 588**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8 588**	**$ -**	**$ -**
Total Depreciation & Amortization Expense	**$ 401 925**	**$ 473 186**	**$ 508 193**	**$ 396 120**	**$ 470 922**	**$ 515 404**	**$ 5 805**	**$ 2 264**	**$ (7 211)**
				% of MH16 Update with Interim Forecast			**1.5%**	**0.5%**	**-1.4%**

* The MH16 Update with Interim forecast balances have been restated to conform to the CEF 18 forecasting methodology (i.e target adjustment amounts have been re-allocated to the various depreciation categories)

Please see the following explanations for differences in depreciation greater than 1% of the total depreciation and amortization balance.

2017/18 Actual vs. 2017/18 MH16 Update with Interim Forecast

The $5.8 million or 1.5% increase is mainly due to the $8.6 million loss on disposition of assets partially offset by a number of smaller reductions in depreciation across the other asset categories. Please see part b) of this response for further details on the loss.

2019/20 Budget vs. 2019/20 MH16 Update with Interim Forecast

The $7.2 million or 1.4% decrease in total depreciation is mainly due to the impact of an overall reduction in the capital forecast for 2018/19 impacting several of the depreciation categories as well as changes in in-service dates and in the mix of assets being constructed.

b) The loss on disposition of $8.6 million in 2017/18 is the result of the retirement of equipment at the Limestone Generating Station and the St. James station, as well as the retirement of street lights replaced with LED bulbs. Please note that the annual change in this account will vary from year to year depending on the nature and age of the assets retired.

REFERENCE:

2017/18 GRA PUB/MH I-18 and Figure 6.18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) File a comparison of the Depreciation and Amortization expense detail for 2017/18 actual and forecast for 2018/19 and 2019/20 with that forecast at the 2017/18 GRA and explain the changes.
b) Provide details on the loss on disposition of $8.588 million in 2017/18.

RESPONSE:

a) Please see the table below for a comparison of the Depreciation and Amortization expense detail for the years 2017/18 actual, 2018/19 Current Outlook and 2019/20 Approved Budget with the MH16 Update with Interim forecast as used in the 2017/18 GRA. Explanations of the differences are provided below.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
ELG rates (no net salvage)

(in thousands)				2017/18 & 2018/19 MH16 Update with Interim *			Increase/ (Decrease)		
	2017/18 Actual	**2018/19 Current Outlook**	**2019/20 Approved Budget**	**2017/18 Forecast**	**2018/19 Forecast**	**2019/20 Forecast**	**2017/18 Difference**	**2018/19 Difference**	**2019/20 Difference**
PROPERTY, PLANT & EQUIPMENT									
Generation									
Hydraulic Generating Stations	115 675	118 189	120 492	116 110	118 481	122 332	(435)	(292)	(1 840)
Thermal Generating Stations	15 596	15 818	15 911	15 608	15 825	15 872	(12)	(7)	39
Diesel Generating Stations	2 079	2 029	1 986	2 037	2 049	2 009	42	(20)	(23)
	$ 133 350	$ 136 036	$ 138 390	$ 133 755	$ 136 355	$ 140 214	$ (405)	$ (318)	$ (1 824)
Transmission									
Transmission	14 203	32 224	40 491	14 470	32 051	41 049	(267)	173	(558)
	$ 14 203	$ 32 224	$ 40 491	$ 14 470	$ 32 051	$ 41 049	$ (267)	$ 173	$ (558)
Stations									
Substations	92 264	131 587	154 992	91 853	137 349	161 763	412	(5 762)	(6 770)
Transformers	1 776	3 716	2 812	1 543	1 677	1 682	233	2 039	1 130
	$ 94 040	$ 135 303	$ 157 805	$ 93 396	$ 139 026	$ 163 445	$ 644	$ (3 723)	$ (5 640)
Distribution									
Subtransmission Lines	7 308	7 744	8 036	7 461	7 854	8 257	(152)	(111)	(221)
Distribution Lines	61 053	65 244	68 592	62 940	65 970	69 633	(1 887)	(725)	(1 041)
Meters & Transformers	5 884	5 853	5 843	6 022	6 030	6 091	(138)	(177)	(248)
	$ 74 245	$ 78 841	$ 82 471	$ 76 423	$ 79 854	$ 83 981	$ (2 178)	$ (1 013)	$ (1 510)
Other									
Communications	20 203	22 226	23 121	20 240	22 972	24 437	(37)	(745)	(1 316)
Motor Vehicles	12 040	13 205	13 685	12 395	13 614	14 364	(355)	(409)	(679)
Structures & Improvements	9 916	10 078	10 277	10 061	10 110	10 331	(144)	(33)	(54)
General Equipment	16 984	16 256	16 307	16 945	16 894	17 318	39	(639)	(1 012)
Miscellaneous	(3 555)	(4 158)	(3 926)	(3 557)	(3 570)	(3 646)	2	(587)	(280)
Corporate Allocation	(1 371)	(1 372)	(1 372)	(1 371)	(1 371)	(1 372)	-	(1)	-
	$ 54 217	$ 56 234	$ 58 092	$ 54 712	$ 58 649	$ 61 432	$ (495)	$ (2 414)	$ (3 340)
							-	-	-
Total Depreciation on PP & E	**$ 370 055**	**$ 438 639**	**$ 477 249**	**$ 372 756**	**$ 445 935**	**$ 490 121**	**$ (2 701)**	**$ (7 296)**	**$ (12 872)**
INTANGIBLES									
Computer Development	21 388	22 123	23 789	21 650	23 105	23 190	(262)	(982)	599
Easements	1 894	2 255	2 334	1 713	1 882	2 092	181	373	242
Total Amortization on Intangibles	**$ 23 282**	**$ 24 378**	**$ 26 123**	**$ 23 364**	**$ 24 987**	**$ 25 282**	**$ (82)**	**$ (609)**	**$ 841**
Loss on Disposition	8 588	2 000	2 000	-	-	-	8 588	2 000	2 000
Total Loss on Disposition	**$ 8 588**	**$ 2 000**	**$ 2 000**	**$ -**	**$ -**	**$ -**	**$ 8 588**	**$ 2 000**	**$ 2 000**
Total Depreciation & Amortization Expense	**$ 401 925**	**$ 465 017**	**$ 505 372**	**$ 396 120**	**$ 470 922**	**$ 515 404**	**$ 5 805**	**$ (5 905)**	**$ (10 032)**
				% of MH16 Update with Interim Forecast			**1.5%**	**-1.3%**	**-1.9%**

Please see the following explanations for differences in the total depreciation and amortization balances for each year.

2017/18 Actual vs. 2017/18 MH16 Update with Interim Forecast

The $5.8 million or 1.5% increase is mainly due to the $8.6 million loss on disposition of assets partially offset by a number of smaller reductions in depreciation across the other asset categories. Please see part b) of this response for further details on the loss.

2018/19 Current Outlook vs. 2018/19 MH16 Update with Interim Forecast

The $5.9 million or 1.3% decrease is mainly due to the planned reduction in the amount forecasted to be placed in-service for Bipole III. MH16 Update with Interim had assumed cumulative $5.0 billion placed in-service by end of the 2018/19, whereas the 2018/19 Current Outlook has a cumulative in-service amount of $4.5 billion.

2019/20 Approved Budget vs. 2019/20 MH16 Update with Interim Forecast

The $10.0 million or 1.9% decrease in total depreciation is mainly due to a cumulative lower in-service amount for Bipole III as a result of the planned reduction in total project costs as well as an overall reduction in the 2018/19 capital forecast which impacts several of the depreciation categories due to changes in dollars spent, in-service dates and the mix of assets being constructed.

b) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

Application Appendix 9

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update Appendix 9 to the most current data available.

RESPONSE:

The tables have been updated to include data up to December 2018. Please see the updated Appendix 9 on Manitoba Hydro's website at the link below:

https://www.hydro.mb.ca/regulatory_affairs/pdf/electric/electric_rate_application_2019/09_appendix_9_-_report_on_hydraulic_generation_water_conditions_and_extraprovincial_energy_exchange_data.pdf

REFERENCE:

Application Appendix 9

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Provide a table showing updates to the forecasts of export revenues, fuel and power purchases, water rentals, and net income for 2018/19 and 2019/20 based up on the updated Appendix 9 data provided in (a).

RESPONSE:

Manitoba Hydro is in the process of preparing a revised 2019/20 Budget based on more current water flow conditions and will provide the requested updates following approval from the MHEB and Province of Manitoba.

REFERENCE:

Application Appendix 9

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Provide a table showing updates to the forecasts of export revenues, fuel and power purchases, water rentals, and net income for 2018/19 and 2019/20 based up on the updated Appendix 9 data provided in (a).

RESPONSE:

The 2018/19 and 2019/20 export revenues, fuel and power purchases, water rentals and net income based on water conditions as of December 31, 2018 (provided in Appendix 9) can be found in Appendix 1 (Updated) filed on February 14, 2019 with Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

2017/18 GRA Coalition/MH II-41

PREAMBLE TO IR (IF ANY):

In the response to 2017/18 GRA Coalition/MH II-41, MH states: *Based on the historic flow record, Manitoba Hydro estimates that there is about a one in six chance of a three year drought starting in any year in the future beyond 2018. This estimate assumes, based on the question, that a drought is defined as three consecutive years of below average hydro generation.*

QUESTION:

Has the probability of a drought as defined in the above referenced information request changed for the three-year periods starting either April 1, 2018 or April 1, 2019? If so, provide and explain the probability of a three-year drought beginning in each year.

RESPONSE:

Using the definition of a drought as three consecutive years of below average hydro generation as per the reference, the estimate that there is about a one in six chance of a three-year drought starting in any year in the future continues to be valid for future periods beyond 2019.

Water conditions for the 2018/19 fiscal year are currently projected to be below average as noted on page 15 of the November 30, 2018 Electric Rate Application, "*Manitoba Hydro expects water flows to be below average through the winter and overall hydraulic generation to be below average*". The probability of three consecutive years of below average hydro generation beginning April 1, 2018 is more likely than the long term expectation of about a one in six chance, given the current anticipated overall below average generation from April 1, 2018 through March 31, 2019.

REFERENCE:

2017/18 GRA Coalition/MH II-41

PREAMBLE TO IR (IF ANY):

In the response to 2017/18 GRA Coalition/MH II-41, MH states: *Based on the historic flow record, Manitoba Hydro estimates that there is about a one in six chance of a three year drought starting in any year in the future beyond 2018. This estimate assumes, based on the question, that a drought is defined as three consecutive years of below average hydro generation.*

QUESTION:

Has the probability of a drought as defined in the above referenced information request changed for the three-year periods starting either April 1, 2018 or April 1, 2019? If so, provide and explain the probability of a three-year drought beginning in each year.

RESPONSE:

As noted in Section 2.1 of the Supplement to the 2019/20 Electric Rate Application, "With Lake Winnipeg levels being below average, Manitoba Hydro expects water flows on the Nelson River to be below average through the winter and overall hydraulic generation to be slightly below average for 2018/19."

The generation for 2018/19 is still expected to be below average based on water conditions as of December 31, 2018. Therefore, the statement in PUB/MH I-27 that "The probability of three consecutive years of below average hydro generation beginning April 1, 2018 is more likely than the long term expectation of about a one in six chance, given the current anticipated overall below average generation from April 1, 2018 through March 31, 2019" remains valid.

Hydraulic generation in 2019/20 is highly uncertain as it is largely dependent on long range precipitation which is impossible to forecast accurately. Average revenues and costs in the

2019/20 Approved Budget are therefore derived from simulations of hydraulic generation using the full record of historic inflows, as was the case for the 2019/20 Interim Budget.

REFERENCE:

Application p.18; 2017/18 GRA Appendix 3.1 IFF16 p.16 and PUB/MH I-19

PREAMBLE TO IR (IF ANY):

In the Application, Manitoba Hydro states: *The 2019/20 Interim Budget shown below in Figure 2.5 assumes average revenues and costs based on Manitoba Hydro's long term record of water and normal weather for the year.*

QUESTION:

a) Confirm whether the 2019/20 Interim Budget (i.e. the second year of this Application's forecast) revenues and costs are based on long-term average water inflows and long-term average reservoir levels from the 100-plus year water flow record. If confirmed, explain whether this represents a departure from past practice, whereby the first year of the forecast (2018/19) is based on known inflow conditions and reservoir levels as of the date of the forecast, and the second year forecast (2019/20) is based on average inflow conditions and forecasted starting reservoir conditions.
b) If the 2019/20 Interim Budget is based on a different methodology from that described in IFF16 at page 16 and PUB/MH I-19, recalculate and provide the 2019/20 Interim Budget Extraprovincial Revenue, Fuel & Power Purchases, Water Rentals, and Net Income based on the previously used methodology.

RESPONSE:

Response to a) and b):
The revenues and costs in the 2019/20 Interim Budget are based on long term average water inflows and reservoir levels from the 100+ year water flow record. As such, there is no departure from past practice. A description of the methodology and the data points underlying the net export revenue forecast for the 2019/20 Interim Budget, which is consistent with past practice, can be found in the response to PUB/MH I-29b.

REFERENCE:

Application p. 23, 26; 2017/18 GRA Supplement to Tab 3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update Figures 4 (Daily Hydraulic Energy from Inflow) and 6 (Total Hydraulic Generation) in the Supplement to Tab 3 from the 2017/18 GRA. Figure 6 should include 2017/18 actual results, as well as the generation resulting from the range of historical flows and the 50% confidence levels of generation for both 2018/19 and 2019/20.

RESPONSE:

Please see figures below. Note that for completeness, this response also includes an update to Figure 5 (Total Energy in Reservoir Storage).

Figure 4. Daily Hydraulic Energy from Inflow

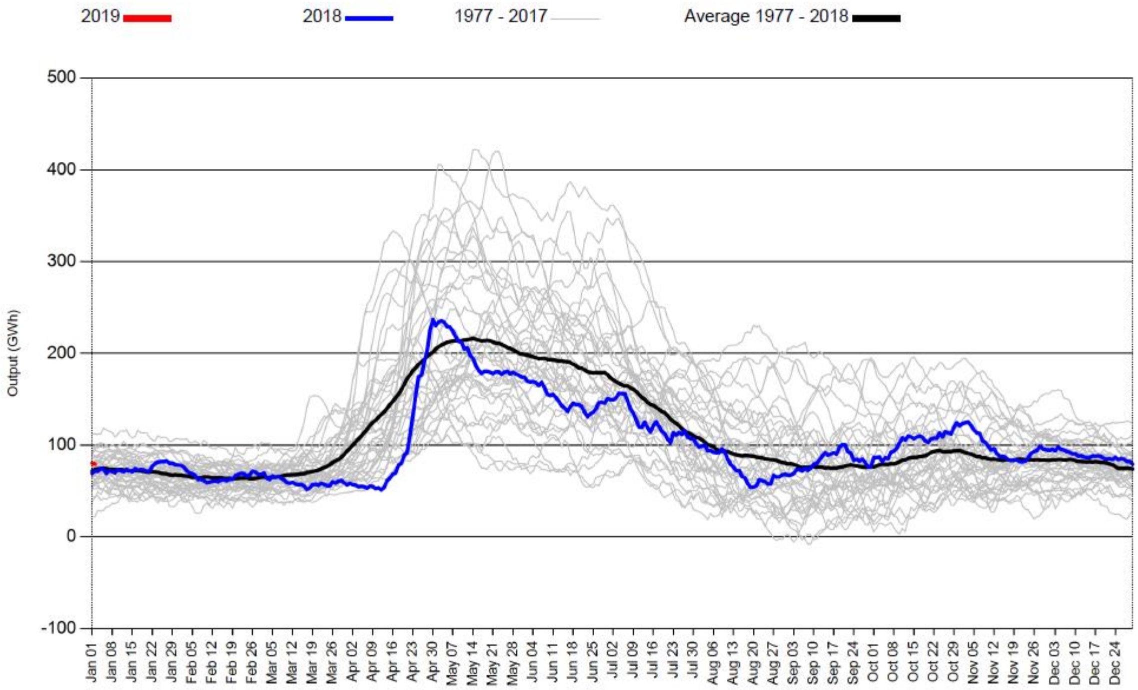


Figure 5. Total Energy in Reservoir Storage

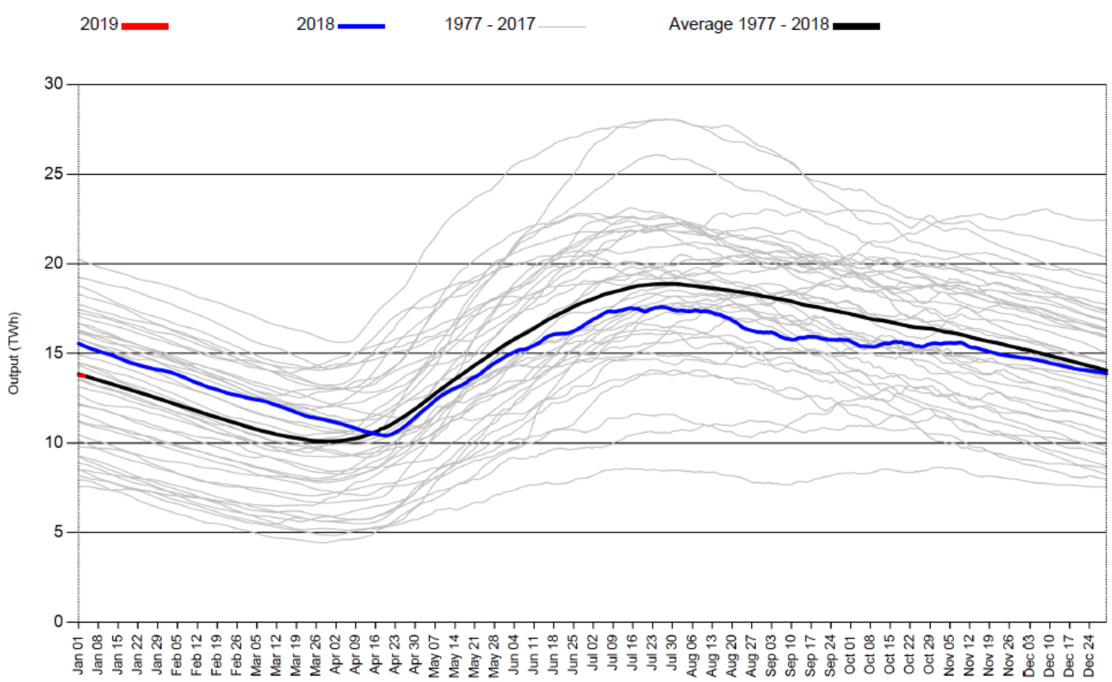
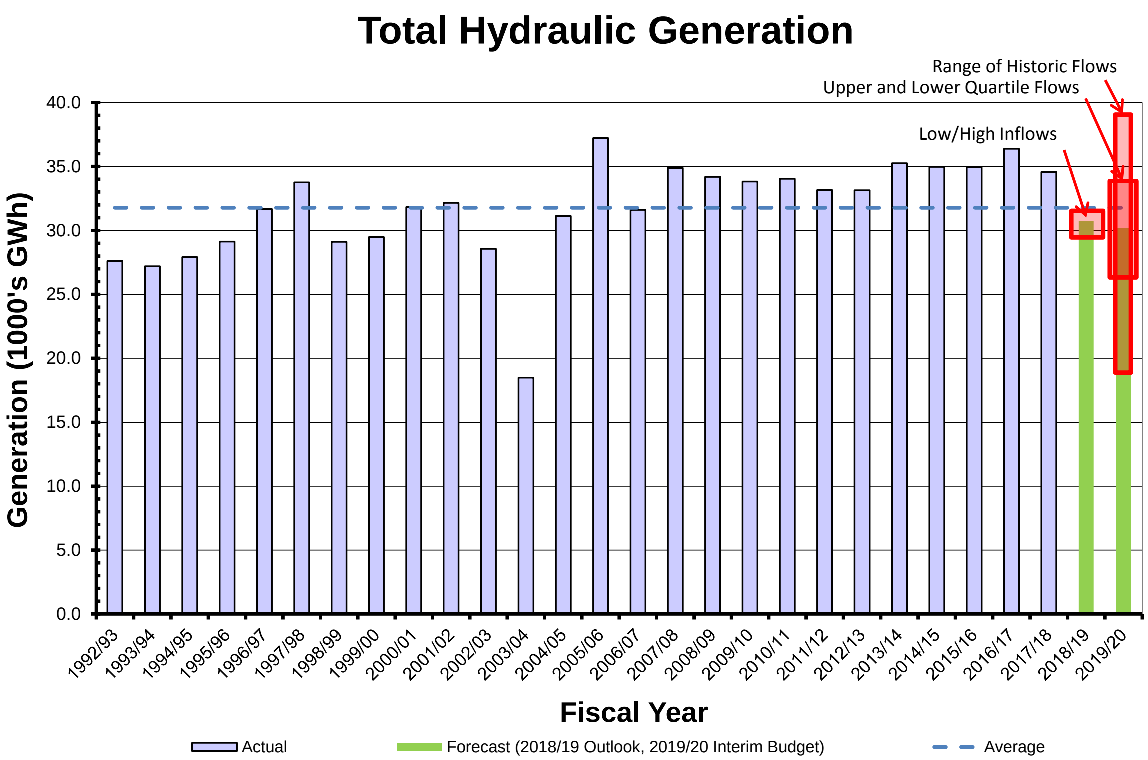


Figure 6. Total Hydraulic Generation



For the 2018/19 Outlook, the full range of historical inflow was not used. The 2018/19 Outlook was prepared in the fall of 2018 when there was greater certainty of inflows for the remainder of the fiscal year, as compared to forecasts prepared prior to the beginning of the fiscal year. For this reason, Manitoba Hydro does not prepare mid-year forecasts using the full range of historical inflows. Instead, a statistical projection of system inflows based on observed conditions is used to develop a confidence band on inflows for the remainder of the year. The high and low flow cases plotted in Figure 6 are based on a 90% confidence band with context to flow conditions when the 2018/19 Outlook was prepared in October 2018.

Using a ranking of results based on the 105 year flow record (1912/13 through 2016/17), the upper and lower quartile and maximum to minimum range are plotted in Figure 6.

REFERENCE:

Application p. 23, 26; 2017/18 GRA Supplement to Tab 3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update Figures 4 (Daily Hydraulic Energy from Inflow) and 6 (Total Hydraulic Generation) in the Supplement to Tab 3 from the 2017/18 GRA. Figure 6 should include 2017/18 actual results, as well as the generation resulting from the range of historical flows and the 50% confidence levels of generation for both 2018/19 and 2019/20.

RESPONSE:

Please see figures below. Note that for completeness, this response also includes an update to Figure 5 (Total Energy in Reservoir Storage). Figures 4 and 5 have been updated to include recent data.

Figure 4. Daily Hydraulic Energy from Inflow

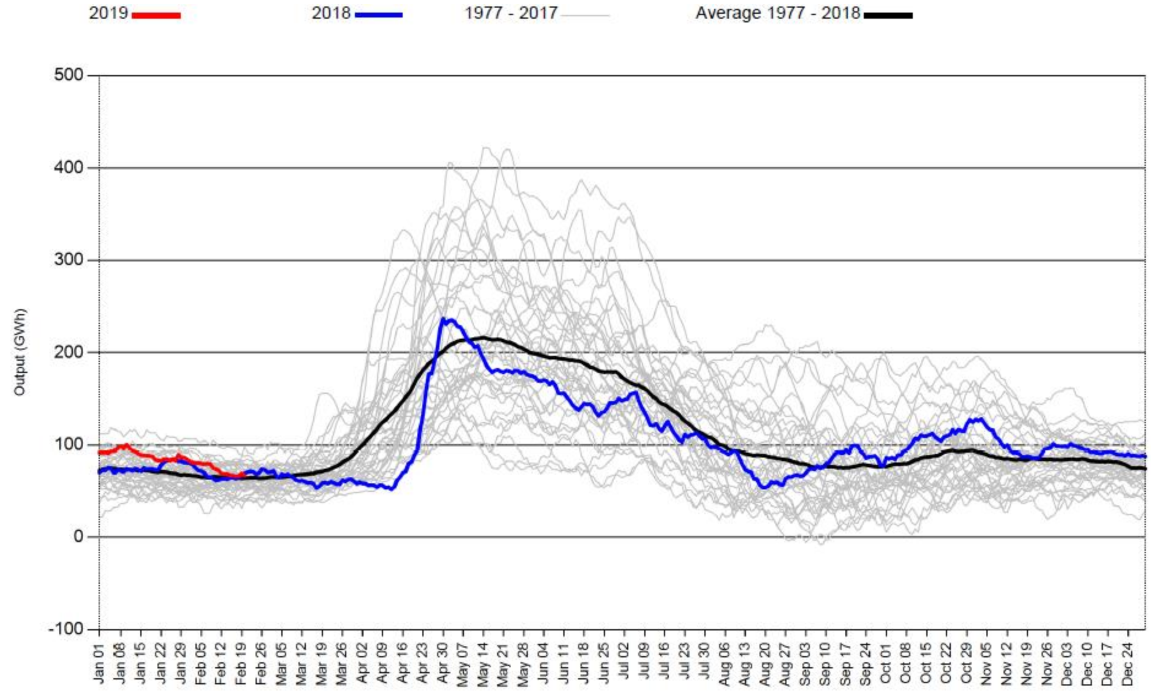


Figure 5. Total Energy in Reservoir Storage

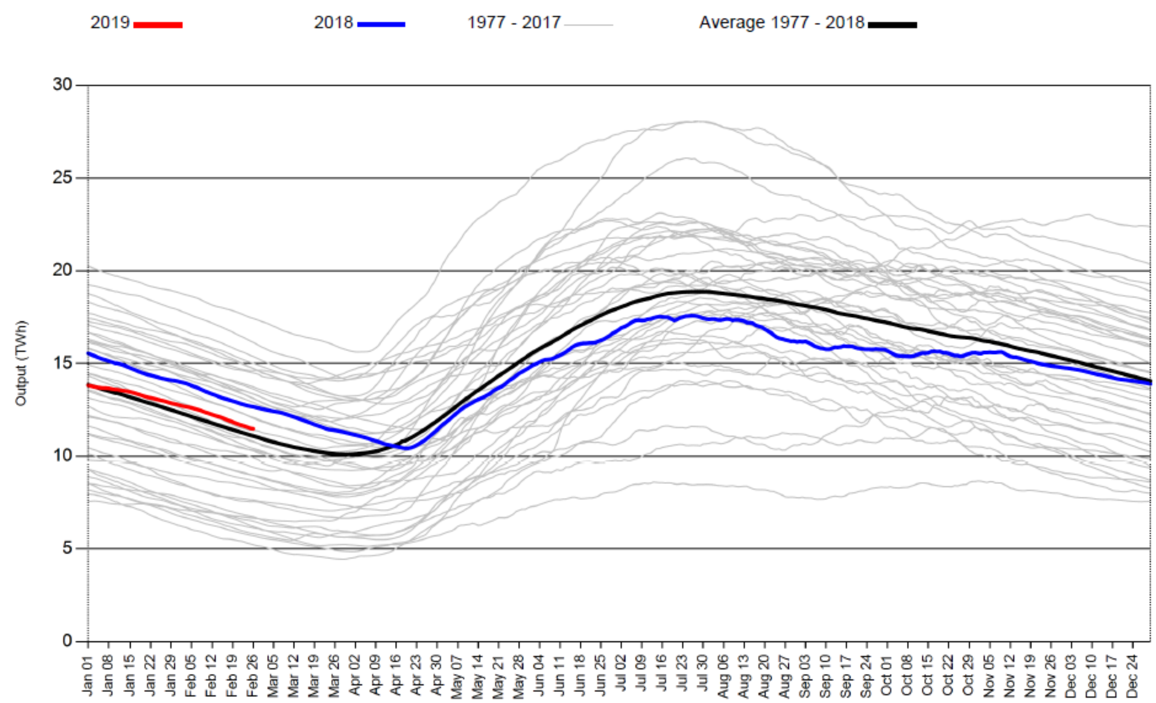
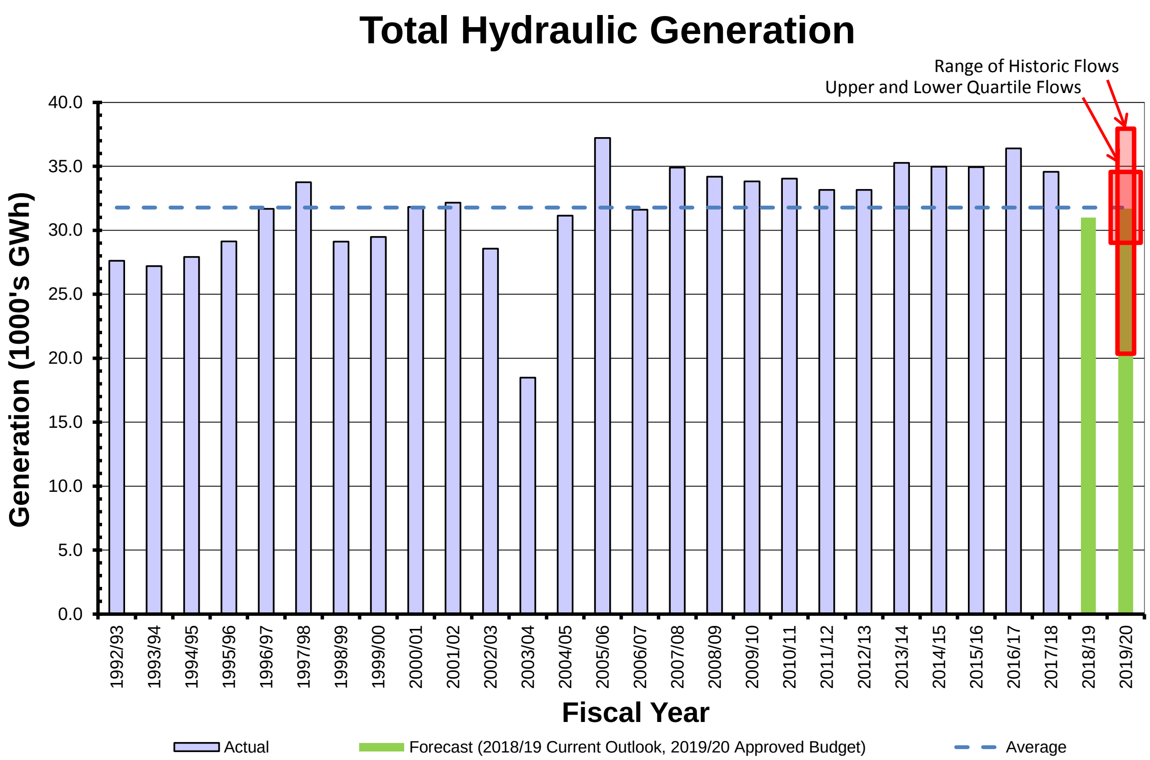


Figure 6. Total Hydraulic Generation



The full range of historical inflow was not used in preparing the 2018/19 Current Outlook. Simulation of hydroelectric generation for the 2018/19 Current Outlook was prepared in January of 2019 when there was relative certainty of inflows for the remainder of the fiscal year, as compared to when forecasts are prepared early in or prior to the beginning of the fiscal year. Only a single expected inflow scenario was used in preparing the 2018/19 Current Outlook. Hydraulic generation derived from that inflow scenario is plotted in Figure 6.

The 2019/20 Approved Budget is based on simulations using the 105 year flow record (1912/13 through 2016/17). The upper and lower quartile, maximum and minimum hydraulic generation values are plotted in Figure 6.

REFERENCE:

Application p. 23, 26; 2017/18 GRA Supplement to Tab 3

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Provide the ranges of net export revenues for each of 2018/19 and 2019/20 based on i) the range of historical flows and ii) the 50% confidence interval of flows.

c) Provide a graph of 2019/20 net income versus water flow probability (i.e. P1 to P100 water flows on the x-axis) for the following rate increases: 0%, 2%, 3% 3.5%, and 4%. Provide the data in the graph in tabular format as well.

d) Provide the probability of water flow at which net income in 2019/20 is $0 based on the applied-for rate increase of 3.5%.

e) On a P50 basis, provide the net income based on the applied-for rate increase of 3.5%.

RATIONALE FOR QUESTION:

RESPONSE:

b) The 2018/19 range of net export revenues provided in the table below is based on a full-year (12-month) simulation of 105 historical water flows. The results of the full-year water flow simulation produced net export revenue under the average (arithmetic mean) of all flow conditions of $159 million (expected value). The 2018/19 outlook for export revenues as filed in Appendix 1 of the 2019/20 Electric Rate Application, includes actual water flow results up to and including September 2018. The 2018/19 average net export revenue including actuals to September 2018 is $141 million.

The table below provides the net export revenue under each historical water flow year for 2018/19. The results between P25 and P75 have been highlighted. The median net export revenue (P50) is approximately $170 million.

2018/19 RANGE OF NET EXPORT REVENUE

#	CUMULATIVE PROBABILITY	NET EXPORT REVENUE
1	1%	(202.50)
2	2%	(60.37)
3	3%	(28.95)
4	4%	(21.94)
5	5%	8.87
6	6%	14.95
7	7%	36.77
8	8%	41.23
9	9%	45.17
10	10%	54.16
11	10%	63.03
12	11%	76.67
13	12%	82.79
14	13%	83.05
15	14%	89.24
16	15%	90.73
17	16%	91.06
18	17%	98.27
19	18%	104.65
20	19%	107.86
21	20%	109.07
22	21%	109.98
23	22%	115.67
24	23%	118.14
25	24%	120.19
26	25%	120.87
27	26%	128.55
28	27%	128.59
29	28%	134.04
30	29%	134.82
31	30%	134.91
32	30%	139.43
33	31%	139.48
34	32%	141.44
35	33%	146.41
36	34%	152.29
37	35%	154.65
38	36%	156.41
39	37%	156.89
40	38%	159.88
41	39%	160.08
42	40%	162.77
43	41%	163.02
44	42%	165.04
45	43%	165.74
46	44%	166.26
47	45%	166.73
48	46%	167.66
49	47%	167.68
50	48%	169.53
51	49%	170.07
52	50%	170.42
53	50%	170.94
54	51%	171.59
55	52%	172.58
56	53%	175.62
57	54%	177.93
58	55%	178.18
59	56%	179.28
60	57%	179.99
61	58%	180.32
62	59%	181.42
63	60%	182.50
64	61%	182.62
65	62%	183.05
66	63%	184.73
67	64%	186.47
68	65%	186.61
69	66%	188.75
70	67%	191.28
71	68%	199.85
72	69%	200.63
73	70%	203.31
74	70%	208.34
75	71%	208.71
76	72%	209.49
77	73%	210.40
78	74%	211.68
79	75%	212.37
80	76%	215.39
81	77%	218.63
82	78%	218.69
83	79%	221.37
84	80%	221.41
85	81%	224.35
86	82%	225.08
87	83%	226.47
88	84%	226.86
89	85%	228.40
90	86%	228.72
91	87%	229.99
92	88%	233.65
93	89%	234.49
94	90%	235.31
95	90%	236.10
96	91%	237.22
97	92%	240.32
98	93%	242.17
99	94%	242.81
100	95%	243.87
101	96%	244.72
102	97%	247.86
103	98%	254.49
104	99%	255.87
105	100%	259.34

The 2019/20 range of net export revenues provided in the table below is based on a full-year (12-month) simulation of 105 historical water flows. The results of the full-year water flow simulation produced net export revenue under the average (arithmetic mean) of all flow conditions of $140 million (expected value). The table below provides the net export revenue under each historical water flow year for 2019/20. The results between P25 and P75 have been highlighted. The median net export revenue (P50) is approximately $167 million.

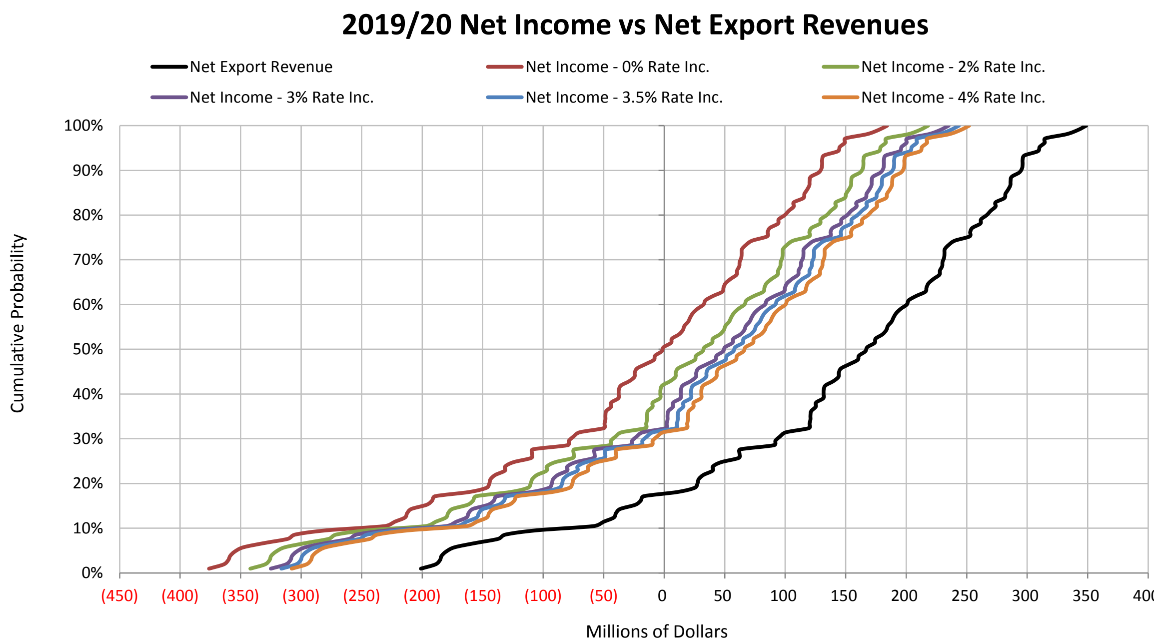
The inherent characteristics of Manitoba Hydro's system and historical water flow record result in a net export revenue distribution that is not symmetric. This skewed net revenue distribution is a result of more expensive thermal generation and imports used in water flows substantially below average being more expensive than the revenue from additional exports, mostly off peak, realized during water flows substantially above average. Further, in extremely high flow conditions, the finite capacity of Manitoba Hydro's hydraulic units results in water being spilled with no net revenue.

A probability distribution that is symmetrical will have the same median value (P50) and arithmetic mean. As Manitoba Hydro's net revenue is not symmetrically distributed, the median value (P50) does not equal the arithmetic mean. Using the median value (P50) will overstate net revenue over the long run. Therefore, Manitoba Hydro uses the mean average and not the median as a planning assumption in order capture the revenue implications of drought and low flow conditions, averaged out over all flow conditions

2019/20 RANGE OF NET EXPORT REVENUE

#	CUMULATIVE PROBABILITY	NET EXPORT REVENUE
1	1%	(201.01)
2	2%	(189.01)
3	3%	(185.30)
4	4%	(183.97)
5	5%	(180.25)
6	6%	(173.36)
7	7%	(156.30)
8	8%	(137.12)
9	9%	(131.13)
10	10%	(105.45)
11	10%	(58.04)
12	11%	(50.09)
13	12%	(41.60)
14	13%	(39.90)
15	14%	(36.48)
16	15%	(23.82)
17	16%	(19.28)
18	17%	(16.96)
19	18%	11.14
20	19%	25.37
21	20%	27.52
22	21%	28.52
23	22%	32.41
24	23%	40.02
25	24%	40.28
26	25%	47.11
27	26%	61.64
28	27%	62.26
29	28%	62.78
30	29%	90.98
31	30%	91.82
32	30%	95.60
33	31%	100.53
34	32%	119.65
35	33%	120.08
36	34%	120.85
37	35%	120.87
38	36%	121.55
39	37%	125.24
40	38%	125.52
41	39%	131.46
42	40%	131.70
43	41%	131.84
44	42%	133.26
45	43%	139.70
46	44%	143.98
47	45%	144.34
48	46%	146.11
49	47%	153.05
50	48%	159.86
51	49%	160.95
52	50%	166.17
53	50%	167.87
54	51%	173.90
55	52%	174.71
56	53%	180.37
57	54%	183.53
58	55%	184.90
59	56%	187.93
60	57%	189.61
61	58%	191.79
62	59%	195.50
63	60%	200.48
64	61%	202.08
65	62%	208.16
66	63%	215.79
67	64%	216.77
68	65%	218.48
69	66%	222.52
70	67%	227.42
71	68%	227.87
72	69%	229.71
73	70%	230.01
74	70%	231.31
75	71%	231.62
76	72%	231.88
77	73%	235.11
78	74%	240.23
79	75%	252.41
80	76%	252.85
81	77%	254.66
82	78%	261.25
83	79%	261.84
84	80%	266.53
85	81%	269.81
86	82%	273.82
87	83%	273.88
88	84%	281.13
89	85%	282.00
90	86%	284.26
91	87%	286.04
92	88%	286.24
93	89%	287.17
94	90%	293.44
95	90%	295.75
96	91%	296.18
97	92%	296.20
98	93%	297.67
99	94%	308.82
100	95%	310.28
101	96%	314.48
102	97%	314.87
103	98%	332.47
104	99%	342.07
105	100%	348.78

c) The following graph contains the 2019/20 net export revenue based on 105 historical water flows as well as the resulting electric net income using the following rate increase assumptions for 2019/20: 0%, 2%, 3%, 3.5% and 4%. The data has also been provided in tabular format below.



From the above graph, it can be observed that:

- With a 0% rate increase in 2019/20, there is a 50% chance that the Corporation will experience net losses. Using the 0% rate increase assumption, net income ranges between a net loss of $125 million and a positive net income of $85 million between the P25 and P75 bounds.
- Assuming the applied for 3.5% rate increase, there is roughly a 30% chance that the Corporation will experience net losses in 2019/20. Using the 3.5% rate increase assumption, 2019/20 net income ranges between a net loss of $65 million and a positive net income of $145 million between the P25 and P75 bounds.

#	Cumulative Probability	Net Export Revenue	Net Income - 0% Rate Inc.	Net Income - 2% Rate Inc.	Net Income - 3% Rate Inc.	Net Income - 3.5% Rate Inc.	Net Income - 4% Rate Inc.
1	1%	(201.01)	(376.13)	(341.99)	(325.07)	(316.33)	(307.81)
2	2%	(189.01)	(364.01)	(329.88)	(312.62)	(304.15)	(295.69)
3	3%	(185.30)	(360.26)	(326.12)	(308.86)	(300.40)	(291.94)
4	4%	(183.97)	(358.63)	(324.78)	(307.52)	(299.05)	(290.59)
5	5%	(180.25)	(354.88)	(320.75)	(303.77)	(295.31)	(286.84)
6	6%	(173.36)	(347.91)	(313.73)	(296.81)	(288.34)	(279.88)
7	7%	(156.30)	(330.68)	(296.49)	(279.57)	(271.11)	(262.64)
8	8%	(137.12)	(310.99)	(277.14)	(260.22)	(251.76)	(243.01)
9	9%	(131.13)	(304.92)	(271.07)	(254.14)	(245.40)	(236.94)
10	10%	(105.45)	(278.96)	(245.11)	(227.91)	(219.45)	(210.99)
11	10%	(58.04)	(230.79)	(196.94)	(180.02)	(171.56)	(163.09)
12	11%	(50.09)	(222.76)	(188.91)	(171.99)	(163.52)	(155.06)
13	12%	(41.60)	(214.20)	(180.35)	(163.43)	(154.97)	(146.50)
14	13%	(39.90)	(212.47)	(178.62)	(161.70)	(153.23)	(144.77)
15	14%	(36.48)	(209.01)	(175.16)	(158.23)	(149.77)	(141.03)
16	15%	(23.82)	(196.24)	(162.39)	(145.46)	(136.72)	(128.26)
17	16%	(19.28)	(191.68)	(157.83)	(140.62)	(132.16)	(123.70)
18	17%	(16.96)	(189.35)	(155.50)	(138.29)	(129.83)	(121.37)
19	18%	11.14	(160.95)	(126.82)	(109.56)	(100.82)	(92.36)
20	19%	25.37	(146.68)	(112.49)	(95.01)	(86.54)	(78.08)
21	20%	27.52	(144.51)	(110.32)	(92.83)	(84.37)	(75.91)
22	21%	28.52	(143.49)	(109.02)	(91.81)	(83.35)	(74.89)
23	22%	32.41	(139.57)	(105.10)	(87.89)	(79.43)	(70.97)
24	23%	40.02	(131.65)	(97.18)	(80.26)	(71.80)	(63.05)
25	24%	40.28	(131.38)	(96.91)	(79.99)	(71.52)	(62.78)
26	25%	47.11	(124.51)	(90.04)	(73.12)	(64.66)	(55.62)
27	26%	61.64	(109.80)	(75.39)	(58.19)	(49.43)	(40.40)
28	27%	62.26	(109.18)	(74.77)	(57.56)	(48.81)	(39.78)
29	28%	62.78	(108.66)	(74.24)	(57.04)	(48.28)	(39.25)
30	29%	90.98	(79.58)	(44.88)	(27.38)	(18.92)	(10.46)
31	30%	91.82	(78.80)	(44.09)	(26.60)	(18.13)	(9.67)
32	30%	95.60	(74.98)	(40.27)	(22.78)	(14.31)	(5.85)
33	31%	100.53	(70.00)	(35.29)	(17.80)	(9.34)	(0.87)
34	32%	119.65	(49.79)	(15.37)	1.55	10.02	18.48
35	33%	120.08	(49.35)	(14.94)	1.99	10.45	18.91
36	34%	120.85	(48.58)	(14.16)	2.76	11.23	19.69
37	35%	120.87	(48.56)	(14.15)	2.78	11.24	19.70
38	36%	121.55	(47.88)	(13.46)	3.46	11.92	20.38
39	37%	125.24	(43.87)	(9.63)	7.29	15.76	24.22
40	38%	125.52	(43.76)	(9.45)	7.48	15.94	24.40
41	39%	131.46	(37.86)	(3.44)	13.48	21.95	30.41
42	40%	131.70	(37.61)	(3.19)	13.73	22.19	30.66
43	41%	131.84	(37.47)	(3.06)	13.87	22.33	30.79
44	42%	133.26	(35.73)	(1.60)	15.33	23.79	32.25
45	43%	139.70	(28.96)	4.89	21.82	30.28	38.74
46	44%	143.98	(24.61)	9.24	26.16	34.63	43.09
47	45%	144.34	(24.29)	9.55	26.48	34.94	43.40
48	46%	146.11	(22.47)	11.38	28.31	36.77	45.23
49	47%	153.05	(15.47)	18.38	35.31	43.77	52.23
50	48%	159.86	(8.57)	25.28	42.20	50.66	59.13
51	49%	160.95	(7.50)	26.35	43.28	51.74	60.20
52	50%	166.17	(2.19)	31.66	48.58	57.05	65.51
53	50%	167.87	(0.47)	33.38	50.30	58.77	67.23

#	Cumulative Probability	Net Export Revenue	Net Income - 0% Rate Inc.	Net Income - 2% Rate Inc.	Net Income - 3% Rate Inc.	Net Income - 3.5% Rate Inc.	Net Income - 4% Rate Inc.
54	51%	173.90	5.61	39.46	56.39	64.85	73.31
55	52%	174.71	6.43	40.28	57.20	65.66	74.13
56	53%	180.37	12.21	46.06	62.99	71.45	79.91
57	54%	183.53	15.39	49.24	66.17	74.63	83.09
58	55%	184.90	16.77	50.62	67.55	76.01	84.47
59	56%	187.93	19.86	53.71	70.63	79.10	87.61
60	57%	189.61	21.55	55.40	72.32	80.79	89.30
61	58%	191.79	23.75	57.60	74.53	82.99	91.51
62	59%	195.50	27.49	61.34	78.27	86.73	95.24
63	60%	200.48	32.53	66.38	83.31	91.82	100.29
64	61%	202.08	34.16	68.01	84.93	93.45	101.91
65	62%	208.16	40.30	74.15	91.13	99.59	108.06
66	63%	215.79	48.00	81.85	98.83	107.29	116.04
67	64%	216.77	49.03	82.88	99.86	108.32	117.34
68	65%	218.48	50.73	84.58	101.55	110.02	118.76
69	66%	222.52	54.82	88.72	105.64	114.11	123.13
70	67%	227.42	59.79	93.69	110.61	119.64	128.38
71	68%	227.87	60.25	94.15	111.08	120.10	128.84
72	69%	229.71	62.06	95.96	112.88	121.91	130.65
73	70%	230.01	62.37	96.27	113.20	122.22	130.96
74	70%	231.31	63.72	97.62	114.82	123.57	132.31
75	71%	231.62	64.00	97.91	115.11	123.86	132.60
76	72%	231.88	64.26	98.16	115.37	124.11	132.86
77	73%	235.11	67.57	101.48	118.96	127.71	136.45
78	74%	240.23	72.73	106.63	124.12	132.86	141.61
79	75%	252.41	85.08	119.82	137.03	145.49	153.95
80	76%	252.85	85.50	119.96	137.45	145.91	154.38
81	77%	254.66	87.37	121.78	139.26	147.73	156.19
82	78%	261.25	94.04	128.73	145.93	154.40	163.14
83	79%	261.84	94.62	129.31	146.52	154.98	163.73
84	80%	266.53	99.65	134.34	151.27	159.73	168.48
85	81%	269.81	102.98	137.67	154.59	163.34	171.80
86	82%	273.82	107.03	141.73	158.93	167.40	175.86
87	83%	273.88	107.11	141.81	159.02	167.48	175.94
88	84%	281.13	115.00	149.13	166.34	174.80	183.26
89	85%	282.00	115.88	150.30	167.22	175.68	184.15
90	86%	284.26	118.16	152.58	169.50	177.96	186.43
91	87%	286.04	119.96	154.38	171.30	179.77	188.23
92	88%	286.24	120.17	154.59	171.51	179.97	188.44
93	89%	287.17	121.11	155.53	172.45	180.92	189.38
94	90%	293.44	127.73	161.87	178.79	187.25	195.72
95	90%	295.75	130.07	164.21	181.13	189.59	198.06
96	91%	296.18	130.52	164.65	181.57	190.04	198.50
97	92%	296.20	130.54	164.67	181.60	190.06	198.52
98	93%	297.67	132.02	166.15	183.08	191.54	200.28
99	94%	308.82	143.58	177.43	194.64	203.10	211.56
100	95%	310.28	145.06	178.91	196.12	204.58	213.04
101	96%	314.48	149.31	183.16	200.36	208.82	217.28
102	97%	314.87	149.71	183.56	200.76	209.22	217.69
103	98%	332.47	167.52	201.65	218.58	227.04	235.50
104	99%	342.07	177.24	211.37	228.30	236.76	245.22
105	100%	348.78	184.31	218.15	235.08	243.54	252.00

d) Using the applied for rate increase of 3.5%, the 2019/20 net income is approximately $0 when the P31 net export revenue forecast is assumed.

e) The 2019/20 net income is approximately $58 million when the P50 net export revenue is assumed with the applied for rate increase of 3.5%.

REFERENCE:

Application p. 23, 26; 2017/18 GRA Supplement to Tab 3

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Provide the ranges of net export revenues for each of 2018/19 and 2019/20 based on i) the range of historical flows and ii) the 50% confidence interval of flows.
c) Provide a graph of 2019/20 net income versus water flow probability (i.e. P1 to P100 water flows on the x-axis) for the following rate increases: 0%, 2%, 3% 3.5%, and 4%. Provide the data in the graph in tabular format as well.
d) Provide the probability of water flow at which net income in 2019/20 is $0 based on the applied-for rate increase of 3.5%.
e) On a P50 basis, provide the net income based on the applied-for rate increase of 3.5%.

RATIONALE FOR QUESTION:

RESPONSE:

b) The 2018/19 Current Outlook net revenue is based on actual water flows up to December 31, 2018 and expected water flows for the remainder of the fiscal year and therefore does not have ranges based on historical water flow records.

The 2019/20 Approved Budget range of net export revenues provided in the table below is based on a full-year (12-month) simulation of 105 historical water flows. Compared to the 2019/20 Interim Budget filed on November 30, 2018, the results of the full-year water flow simulation reflect higher starting water storage levels allowing more storage to be drawn down throughout the year and produce net export revenue under the average (arithmetic mean) of all flow conditions of $174 million (expected value). The table below provides the net export revenue under each historical water flow year for

2019/20. The results between P25 and P75 have been highlighted. The median net export revenue (P50) is approximately $195 million.

The inherent characteristics of Manitoba Hydro’s system and historical water flow record result in a net export revenue distribution that is not symmetric. This skewed net revenue distribution is a result of more expensive thermal generation and imports used in water flows substantially below average being more expensive than the revenue from additional exports, mostly off peak, realized during water flows substantially above average. Further, in extremely high flow conditions, the finite capacity of Manitoba Hydro’s hydraulic units results in water being spilled with no net revenue.

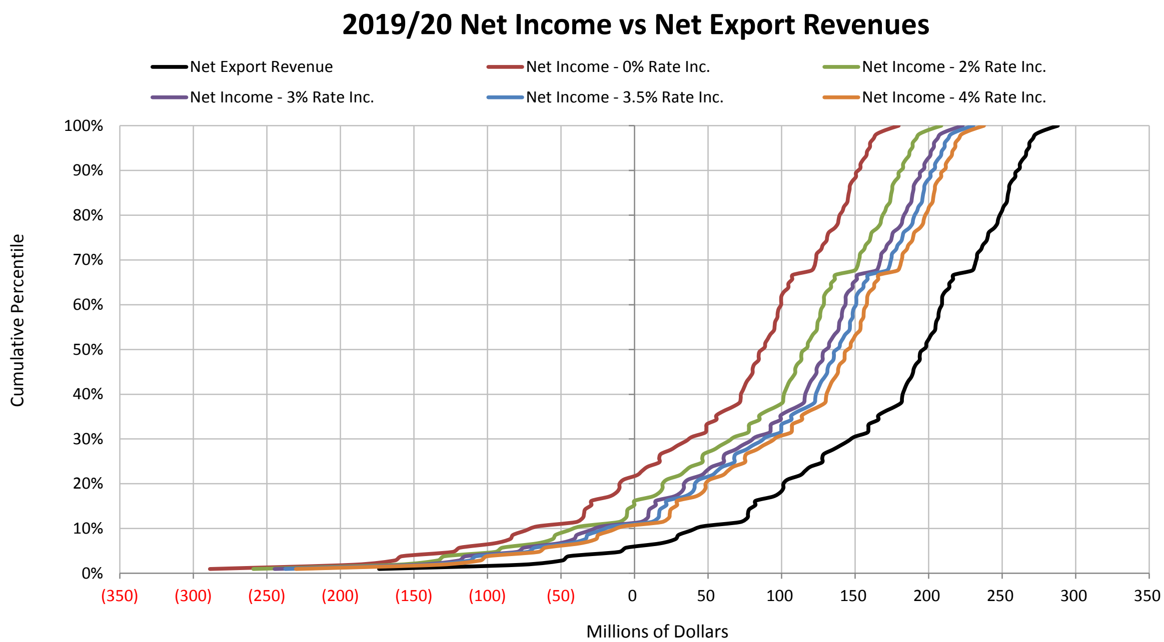
A probability distribution that is symmetrical will have the same median value (P50) and arithmetic mean. As Manitoba Hydro’s net revenue is not symmetrically distributed, the median value (P50) does not equal the arithmetic mean. Using the median value (P50) will overstate net revenue over the long run. Therefore, Manitoba Hydro uses the mean average and not the median as a planning assumption in order capture the revenue implications of drought and low flow conditions, averaged out over all flow conditions

2019/20 RANGE OF NET EXPORT REVENUE

#	Cumulative Percentile	Net Export Revenue
1	1%	(173.69)
2	2%	(76.85)
3	3%	(49.05)
4	4%	(44.64)
5	5%	(10.58)
6	6%	(5.62)
7	7%	17.32
8	8%	27.78
9	9%	30.03
10	10%	38.21
11	10%	46.25
12	11%	71.75
13	12%	76.74
14	13%	77.14
15	14%	78.06
16	15%	82.22
17	16%	82.32
18	17%	94.32
19	18%	99.22
20	19%	101.25
21	20%	101.28
22	21%	104.24
23	22%	112.64
24	23%	115.98
25	24%	119.68
26	25%	127.46
27	26%	127.65
28	27%	128.85
29	28%	134.87
30	29%	140.14
31	30%	145.16
32	30%	149.53
33	31%	158.27
34	32%	159.05
35	33%	159.51
36	34%	165.67
37	35%	165.73
38	36%	170.44
39	37%	176.54
40	38%	181.34
41	39%	181.87
42	40%	182.33
43	41%	183.42
44	42%	184.56
45	43%	186.03
46	44%	188.14
47	45%	189.32
48	46%	189.91
49	47%	191.38
50	48%	193.85
51	49%	193.93
52	50%	194.66
53	50%	198.09

#	Cumulative Percentile	Net Export Revenue
54	51%	198.48
55	52%	200.20
56	53%	201.81
57	54%	204.26
58	55%	204.71
59	56%	205.16
60	57%	206.54
61	58%	206.79
62	59%	207.54
63	60%	208.99
64	61%	209.14
65	62%	209.35
66	63%	211.03
67	64%	214.01
68	65%	214.08
69	66%	216.64
70	67%	216.96
71	68%	229.39
72	69%	231.11
73	70%	231.92
74	70%	232.79
75	71%	233.16
76	72%	235.67
77	73%	236.88
78	74%	239.33
79	75%	240.23
80	76%	240.99
81	77%	244.53
82	78%	246.62
83	79%	247.23
84	80%	248.33
85	81%	249.86
86	82%	250.95
87	83%	253.01
88	84%	253.57
89	85%	253.95
90	86%	254.67
91	87%	254.88
92	88%	256.51
93	89%	258.91
94	90%	259.02
95	90%	261.89
96	91%	262.01
97	92%	263.72
98	93%	266.04
99	94%	266.51
100	95%	268.39
101	96%	268.59
102	97%	270.91
103	98%	272.75
104	99%	279.12
105	100%	287.85

c) The following graph contains the 2019/20 net export revenue based on 105 historical water flows as well as the resulting electric net income using the following rate increase assumptions for 2019/20: 0%, 2%, 3%, 3.5% and 4%. The data has also been provided in tabular format below.



From the above graph, it can be observed that:

- With a 0% rate increase in 2019/20, there is a 21% chance that the Corporation will experience net losses. Using the 0% rate increase assumption, net income ranges between $17 million and $131 million between the P25 and P75 bounds.
- Assuming the applied for 3.5% rate increase, there is roughly a 10% chance that the Corporation will experience net losses in 2019/20. Using the 3.5% rate increase assumption, 2019/20 net income ranges between $68 million and $182 million between the P25 and P75 bounds.

#	Cumulative Percentile	Net Export Revenue	Net Income - 0% Rate Inc.	Net Income - 2% Rate Inc.	Net Income - 3% Rate Inc.	Net Income - 3.5% Rate Inc.	Net Income - 4% Rate Inc.
1	1%	(173.69)	(288.70)	(259.21)	(244.72)	(237.48)	(230.23)
2	2%	(76.85)	(190.87)	(161.63)	(147.14)	(139.90)	(132.65)
3	3%	(49.05)	(162.98)	(133.74)	(119.25)	(112.01)	(104.76)
4	4%	(44.64)	(158.09)	(129.12)	(114.63)	(107.38)	(100.14)
5	5%	(10.58)	(123.72)	(94.74)	(80.00)	(72.76)	(65.51)
6	6%	(5.62)	(118.80)	(89.82)	(75.08)	(67.84)	(60.59)
7	7%	17.32	(95.58)	(66.35)	(51.86)	(44.61)	(37.37)
8	8%	27.78	(84.71)	(55.73)	(41.24)	(33.49)	(26.25)
9	9%	30.03	(82.56)	(53.58)	(39.09)	(31.85)	(24.60)
10	10%	38.21	(74.25)	(45.27)	(30.53)	(23.29)	(15.79)
11	10%	46.25	(66.03)	(36.55)	(22.06)	(14.81)	(7.57)
12	11%	71.75	(39.86)	(10.88)	3.86	11.16	18.41
13	12%	76.74	(35.17)	(5.94)	8.87	16.11	23.36
14	13%	77.14	(34.29)	(5.07)	9.49	16.73	23.97
15	14%	78.06	(33.51)	(4.53)	10.27	17.52	24.76
16	15%	82.22	(29.29)	(0.06)	14.49	21.74	28.98
17	16%	82.32	(29.19)	0.04	14.59	21.83	29.08
18	17%	94.32	(17.13)	12.16	26.65	33.89	41.39
19	18%	99.22	(12.18)	17.11	31.60	39.10	46.34
20	19%	101.25	(10.20)	19.09	33.58	40.82	48.32
21	20%	101.28	(10.15)	19.14	33.63	41.12	48.37
22	21%	104.24	(7.14)	22.15	36.64	44.13	51.38
23	22%	112.64	1.63	30.67	45.41	52.65	59.90
24	23%	115.98	5.12	34.42	48.90	56.15	63.39
25	24%	119.68	9.02	38.24	52.73	59.98	67.22
26	25%	127.46	16.74	45.97	60.46	67.70	74.95
27	26%	127.65	16.80	46.03	60.52	67.76	75.01
28	27%	128.85	18.00	47.23	61.72	68.96	76.21
29	28%	134.87	24.76	53.99	68.48	75.72	82.97
30	29%	140.14	29.42	58.65	73.14	80.38	87.63
31	30%	145.16	34.95	63.93	78.67	85.91	93.16
32	30%	149.53	39.19	68.17	82.65	89.90	97.39
33	31%	158.27	48.05	77.03	91.77	99.01	106.26
34	32%	159.05	48.84	77.82	92.55	99.80	107.04
35	33%	159.51	49.34	78.32	93.06	100.30	107.55
36	34%	165.67	55.57	84.80	99.28	106.53	113.77
37	35%	165.73	55.62	84.84	99.33	106.58	113.82
38	36%	170.44	60.30	89.53	104.02	111.26	118.51
39	37%	176.54	66.51	95.74	110.23	117.47	124.71
40	38%	181.34	71.33	100.55	115.04	122.29	129.53
41	39%	181.87	72.20	101.18	115.66	122.91	130.15
42	40%	182.33	72.36	101.59	116.08	123.32	130.56
43	41%	183.42	73.77	102.75	117.24	124.48	131.73
44	42%	184.56	75.01	103.98	118.47	125.72	132.96
45	43%	186.03	76.35	105.33	119.82	127.06	134.30
46	44%	188.14	78.52	107.50	121.99	129.23	136.47
47	45%	189.32	80.27	109.25	123.74	130.98	138.23
48	46%	189.91	80.34	109.32	123.80	131.29	138.54
49	47%	191.38	81.42	110.64	125.13	132.38	139.62
50	48%	193.85	84.37	113.35	127.84	135.08	142.58
51	49%	193.93	84.40	113.38	127.87	135.63	142.87
52	50%	194.66	85.07	114.04	128.53	135.78	143.27
53	50%	198.09	88.49	117.47	131.95	139.20	146.70

#	Cumulative Percentile	Net Export Revenue	Net Income - 0% Rate Inc.	Net Income - 2% Rate Inc.	Net Income - 3% Rate Inc.	Net Income - 3.5% Rate Inc.	Net Income - 4% Rate Inc.
54	51%	198.48	88.93	117.90	132.39	139.89	147.13
55	52%	200.20	90.67	119.65	134.14	141.63	148.88
56	53%	201.81	92.32	121.29	136.03	143.28	150.52
57	54%	204.26	94.83	123.81	138.55	146.06	153.30
58	55%	204.71	95.29	124.26	139.00	146.51	153.76
59	56%	205.16	95.65	124.63	139.37	146.61	153.86
60	57%	206.54	97.12	126.10	140.84	148.29	155.59
61	58%	206.79	97.33	126.31	141.05	148.35	155.80
62	59%	207.54	98.00	126.97	141.72	148.96	156.20
63	60%	208.99	99.67	128.65	143.39	150.63	157.87
64	61%	209.14	99.68	128.87	143.61	150.86	158.15
65	62%	209.35	99.90	128.92	143.66	150.91	158.37
66	63%	211.03	101.55	130.53	145.27	152.51	159.76
67	64%	214.01	104.56	133.54	148.28	155.52	162.77
68	65%	214.08	104.68	133.66	148.40	155.91	163.15
69	66%	216.64	107.28	136.26	151.26	158.51	165.75
70	67%	216.96	107.59	136.57	151.58	158.82	166.06
71	68%	229.39	120.11	149.33	164.09	171.33	178.58
72	69%	231.11	122.28	151.51	165.99	173.24	180.47
73	70%	231.92	123.04	152.27	166.75	174.00	181.24
74	70%	232.79	123.54	153.04	167.52	174.77	182.01
75	71%	233.16	123.99	153.48	167.97	175.21	182.46
76	72%	235.67	126.92	156.14	170.62	177.87	185.11
77	73%	236.88	128.01	157.24	171.73	178.98	186.22
78	74%	239.33	130.52	159.75	174.24	181.48	188.73
79	75%	240.23	131.06	160.55	175.04	182.29	189.53
80	76%	240.99	132.21	161.44	175.93	183.17	190.41
81	77%	244.53	136.06	165.03	179.52	186.76	194.00
82	78%	246.62	138.19	167.17	181.65	188.89	196.13
83	79%	247.23	138.77	167.75	182.23	189.47	196.72
84	80%	248.33	139.48	168.73	183.21	190.46	197.70
85	81%	249.86	141.43	170.41	184.89	192.13	199.38
86	82%	250.95	142.43	171.40	185.89	193.14	200.38
87	83%	253.01	144.60	173.57	188.05	195.30	202.54
88	84%	253.57	145.14	174.12	188.60	195.84	203.08
89	85%	253.95	145.58	174.55	189.03	196.28	203.52
90	86%	254.67	146.24	175.22	189.70	196.95	204.19
91	87%	254.88	146.50	175.47	189.95	197.20	204.44
92	88%	256.51	148.13	177.10	191.58	198.83	206.07
93	89%	258.91	150.55	179.53	194.01	201.25	208.49
94	90%	259.02	150.64	179.62	194.10	201.34	208.59
95	90%	261.89	153.53	182.50	196.98	204.23	211.54
96	91%	262.01	153.66	182.63	197.11	204.36	211.67
97	92%	263.72	155.38	184.35	198.83	206.08	213.39
98	93%	266.04	157.65	186.63	201.11	208.35	215.66
99	94%	266.51	158.17	187.14	201.63	208.87	216.18
100	95%	268.39	160.07	189.05	203.53	210.84	218.08
101	96%	268.59	160.26	189.23	203.72	211.02	218.27
102	97%	270.91	162.59	191.57	206.05	213.36	220.60
103	98%	272.75	164.45	193.42	207.91	215.21	222.46
104	99%	279.12	170.86	199.83	214.38	221.62	228.87
105	100%	287.85	179.63	208.60	223.15	230.39	237.64

d) Using the applied for rate increase of 3.5%, the 2019/20 net income is approximately $0 when the P10 net export revenue forecast is assumed.

e) The 2019/20 net income is approximately $136 million when the P50 net export revenue is assumed with the applied for rate increase of 3.5%.

REFERENCE:

Application p. 26, 27

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide the Degree Days Heating (DDH) for the Colder Than Normal Winter Weather and Warmer Than Normal Winter Weather sensitivities in Figure 2.10. Are these DDH values the warmest and coldest on record? If not, explain why these particular DDH values were selected for the sensitivity analysis.

b) Provide the range of net incomes for 2019/20 within a 50% confidence interval of DDH.

c) Provide the range of net incomes for 2019/20 within a 50% confidence interval of Degree Days Cooling.

RESPONSE:

a) The Degree Day Heating ("DDH") for the colder and warmer than normal winter weather sensitivities were based on the extreme weather sensitivities that have occurred in Manitoba since 1960/61. For the purpose of the sensitivities provided in the application, a range of +/- [redacted] DDH with an impact of +/- 1,000 GWh to the domestic Gross Firm Energy was utilized. 9a

b) Utilizing a 50% confidence interval of DDH, the respective range of DDH would be +/- [redacted], resulting in +/- $10 million of net income sensitivity. 9a

c) Utilizing a 50% confidence interval of DDC, the respective range of DDC would be +/- 43.1, resulting in +/- $4 million of net income sensitivity.

REFERENCE:

2017/18 GRA MFR 98; Application pg. 8

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update MFR 98 with the monthly degree days heating and degree days cooling for 2017/18 actual and 2018/19 actual to date.
b) With reference to item (a), provide the normal monthly DDH and DDC, and the normal monthly DDH and DDC for the test year.

RESPONSE:

Response to parts a) & b)

An update to PUB MFR 98 from the 2017/18 GRA is provided below:

Figure 1. Monthly Degree Days Heating History in Winnipeg

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total	
2018/19	[redacted]													9a
2017/18														9a

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total	
Normal	[redacted]													9a

Figure 2. Monthly Degree Days Cooling History in Winnipeg

Fiscal Year	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
2018/19	0.0	31.9	67.6	79.4	74.8	1.1	0.0	0.0	0.0	-	-	-	254.8
2017/18	0.0	0.0	28.2	47.9	29.0	13.4	0.0	0.0	0.0	0.0	0.0	0.0	118.5
2016/17	0.0	16.3	26.0	57.1	50.3	10.8	2.8	0.0	0.0	0.0	0.0	0.0	163.3
2015/16	0.0	8.2	17.6	84.1	56.7	33.5	0.0	0.0	0.0	0.0	0.0	0.0	200.1
2014/15	0.0	22.0	25.2	48.1	68.0	11.5	0.0	0.0	0.0	0.0	0.0	0.0	174.8
2013/14	0.0	0.0	31.2	55.2	79.4	18.2	0.0	0.0	0.0	0.0	0.0	0.0	184.0
2012/13	0.0	5.0	39.9	137.0	59.9	12.9	0.0	0.0	0.0	0.0	0.0	0.0	254.7

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Normal	0.1	6.2	33.4	67.2	55.3	12.6	0.6	0.0	0.0	0.0	0.0	0.0	175.4

REFERENCE:

2017/18 GRA PUB MFR 44

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide a schedule of actual and forecast payments made to the Province and Municipalities for five historical years and the test year.

RESPONSE:

The below schedule summarizes payments made to the Province and Municipalities for five historical years, the 2018/19 Outlook, and the 2019/20 Interim Budget.

Payments to the Province and Municipalities ($Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Capital Taxes	Payroll Taxes	Municipal GILT and Business Taxes	Total Provincial Payments (GILT & Business Tax Not Included)
2014	118	96	60	11	23	285
2015	117	105	62	12	25	296
2016	117	118	69	12	25	316
2017	122	132	80	12	26	346
2018	116	154	92	12	25	374
2019	109	183	105	12	25	409
2020	101	212	112	12	25	437

Note: GILT stands for “Grants in Lieu of Taxes”.

REFERENCE:

2017/18 GRA PUB MFR 44

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide a schedule of actual and forecast payments made to the Province and Municipalities for five historical years and the test year.

RESPONSE:

The schedule below summarizes payments made to the Province and Municipalities for five historical years, the 2018/19 Current Outlook, and the 2019/20 Approved Budget.

Payments to the Province and Municipalities ($Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Capital Taxes	Payroll Taxes	Municipal GILT and Business Taxes	Total Provincial Payments (GILT & Business Tax Not Included)
2014	118	96	60	11	23	285
2015	117	105	62	12	25	296
2016	117	118	69	12	25	316
2017	122	132	80	12	26	346
2018	116	154	92	12	25	374
2019	104	182	101	12	25	399
2020	107	203	110	12	26	431

Note: GILT stands for “Grants in Lieu of Taxes”.

REFERENCE:

2017/18 GRA MIPUG-30

PREAMBLE TO IR (IF ANY):

QUESTION:

Update the MIPUG-30 chart provided on page 178 of Order 59/18 for most current available actual information to date and most current available forecast information for the next test year.

RESPONSE:

The information for other Provincial entities was prepared by Mr. Patrick Bowman on behalf of the Manitoba Industrial Power Users Group ("MIPUG") and formed part of Mr. Bowman's evidence during the 2017/18 & 2018/19 General Rate Application. The referenced evidence was not Manitoba Hydro's evidence. Manitoba Hydro has provided updated information as to its payments to government in the response to PUB/MH I-32. Manitoba Hydro does not have in its possession the information to update payments by other entities.

REFERENCE:

Application page 14, Figure 2.7; Additional Information Attachment 5

PREAMBLE TO IR (IF ANY):

In its Application, Manitoba Hydro states:

The increase of $52 million in Net Finance Expense is primarily attributable to higher forecasted interest rates. Subsequent to the filing of Exhibit MH- 93 and during the course of the 2017/18 & 2018/19 GRA, the Bank of Canada interest rates rose such that the cost advantage to borrowing more shorter term maturities did not materialize. The yield curve continued to flatten such that there is now only a minimal difference between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. As such, Manitoba Hydro reverted to a longer term borrowing strategy of targeting a 20 year weighted average term to maturity ("WATM") for new borrowings as opposed to the 12 year assumption in Exhibit MH-93.

QUESTION:

a) Refile table 5 of the interest rate forecast including the 2018/19 average actual for Q1, Q2, and Q3 and forecast for Q4.
b) Update table 6 detailing the relied-upon interest forecasts by forecaster for both short term and long term interest rates indicating: the date of the forecast, whether the forecast represents end of period or average data, and if any adjustments were made to end of period data forecasts to average the results. Provide the detail of adjustments made.
c) Provide an update to the short term and long term interest rate forecast based on currently available forecasts. Indicate the vintage of each forecast and provide a comparison with that used for forecasting 2018/19 and 2019/20 rates.
d) Indicate how finance expense would change for 2018/19 and 2019/20 utilizing the updated interest rate forecast.

RESPONSE:

a) Table 1 below provides an update to Additional Information Attachment 5 Table 5 to include 2018/19.

Table 1 – Manitoba Hydro's Forecasted Interest Rates Incorporated in 2019/20 Interim Budget – FISCAL YEAR

	CAN Short-Term Interest Rate				CAN Floating Debt Interest Rate						CAN Fixed Debt Interest Rate			
	Consensus Benchmark 90 Day T-Bill Rate	Manitoba Spread	PGF	**MH Interest Rate**	Consensus Benchmark 90 Day T-Bill Rate	Spread from CAN T-Bill to CAN BA Rate	CAN 90 Day BA Rate	Average Margin Level	PGF	**MH Interest Rate**	Consensus Benchmark Long Term Bond 10+ Rate	Manitoba Spread	PGF	**MH Interest Rate**
2018/19 *	1.52		1.00	**2.50**	1.52	0.44	1.95	0.64	1.00	**3.59**	2.64	0.86	1.00	4.50
2019/20	2.21		1.00	**3.20**	2.21	0.41	2.60	0.64	1.00	**4.24**	3.05	0.94	1.00	5.00
2020/21	2.45		1.00	**3.45**	2.45	0.41	2.85	0.64	1.00	**4.49**	3.13	0.94	1.00	5.05
2021/22	2.35		1.00	**3.35**	2.35	0.41	2.75	0.64	1.00	**4.39**	3.07	0.94	1.00	5.00
2022/23	2.37		1.00	**3.35**	2.37	0.41	2.80	0.64	1.00	**4.44**	3.11	0.94	1.00	5.05
2023/24 & on	2.69		1.00	**3.70**	2.69	0.41	3.10	0.64	1.00	**4.74**	3.26	0.94	1.00	5.20

** The calculation of 2018/19 forecast interest rate reflects the Winter 2017 update based on the average four quarter forecast in 2018/19. 2018/19 finance expense reflects actual rates to the end of October 2018 with remaining months reflecting the average four quarter forecast to the end of the fiscal year.*

b) Table 2 on the following page depicts the sources used to derive the forecast of Canadian 3 month T-Bill rates for each quarter of the 2018/19 and 2019/20 period, as utilized the 2019/20 Interim Budget.

Table 3 on the following page depicts the sources used to derive the forecast of Canadian LT bond 10 Yr+ rates for each quarter of the 2018/19 and 2019/20 period, as utilized the 2019/20 Interim Budget.

Table 4 on the following page depicts the sources used to derive the forecast of Canadian 3 month T-Bill rates for each quarter of the 2018/19 and 2019/20 period, updated to reflect the consensus view as at the end of December 2018.

Table 5 on the following page depicts the sources used to derive the forecast of Canadian LT bond 10 Yr+ rates for each quarter of the 2018/19 and 2019/20 period, updated to reflect the consensus view as at the end of December 2018.

For forecasters that provided end of period rates, the rates provided in Tables 2 to 5 reflect rates adjusted to a comparable average period basis. For example, Desjardin’s forecast provided end of period rates. Their December 2017 forecast for 2018 Q2 end of period is 1.35% and 2018 Q3 end of period is 1.55% for Canada 3-month T-Bill. In order to place the forecast on an equivalent basis for a 2018 Q3 average period forecast, Desjardin’s 2018 Q2 end of period forecast of 1.35% was averaged with their 2018 Q3 end of period forecast of 1.55% to approximate an average period 2018 Q3 forecast of 1.45%. This value is shown in Table 2. This process was followed for all subsequent quarters and for all forecasters that provided end of period rates.

Table 2 – Canadian 3 month T-Bill Rate %, as utilized in the 2019/20 Interim Budget

Forecaster	Forecast Date	End of Period or Average	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1
BMO Nesbitt Burns	22-Dec-17	Average	1.20	1.45	1.70	1.90	2.15	2.35	2.35	*
CIBC	17-Dec-17	End of Period	1.10	1.23	1.33	1.45	1.60	1.83	2.00	2.25
Desjardins	18-Dec-17	End of Period	1.30	1.45	1.65	1.78	1.93	2.15	2.25	2.15
Laurentian	15-Dec-17	End of Period	1.23	1.25	1.25					
National Bank	1-Dec-17	End of Period	1.55	1.79	1.93	1.99	2.05	2.12	2.18	
Royal Bank	11-Dec-17	End of Period	1.10	1.33	1.58	1.88	2.15			
Scotiabank	5-Dec-17	End of Period	1.13	1.38	1.55	1.70	1.95	2.23	2.38	
TD Bank	14-Dec-17	End of Period	1.32	1.44	1.57	1.69	1.82	1.94	2.07	2.19
IHS Global Insight	8-Dec-17	Average	1.26	1.51	1.76	2.01	2.26	2.51	2.76	3.03
Conference Board	15-Dec-17	Average	1.29	1.54	1.79	2.04	2.19	2.31	2.54	2.69

	2018/19	2019/20
EO 2017 - December	**1.50**	**2.20**

Note: BMO Nesbitt Burn's long-run assumptions are considered proprietary and cannot be disclosed

Table 3 – Canadian LT bond 10 Yr+ Rate %, as utilized in the 2019/20 Interim Budget

Forecaster	Forecast Date	End of Period or Average	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1
BMO Nesbitt Burns	22-Dec-17	Average	2.30	2.43	2.55	2.73	2.93	3.03	3.13	*
CIBC	17-Dec-17	End of Period	2.39	2.46	2.48	2.48	2.50	2.58	2.68	2.83
Desjardins	18-Dec-17	End of Period	2.38	2.55	2.75	2.88	2.94	3.00	3.04	2.90
Laurentian	15-Dec-17	End of Period	2.29	2.41	2.54					
National Bank	1-Dec-17	End of Period	2.57	2.73	2.82	2.88	2.96	3.05	3.13	
Royal Bank	11-Dec-17	End of Period	2.44	2.66	2.86	3.00	3.11			
Scotiabank	5-Dec-17	End of Period	2.30	2.46	2.61	2.73	2.81	2.88	2.95	
TD Bank	14-Dec-17	End of Period	2.38	2.55	2.70	2.81	2.88	2.93	2.96	2.99
IHS Global Insight	8-Dec-17	Average	2.51	2.71	2.86	3.00	3.14	3.23	3.28	3.34
Conference Board	15-Dec-17	Average	2.62	2.88	3.01	3.23	3.45	3.59	3.68	3.68

	2018/19	2019/20
EO 2017 - December	**2.65**	**3.05**

Note: BMO Nesbitt Burn's long-run assumptions are considered proprietary and cannot be disclosed

Table 4 – Canadian 3 month T-Bill Rate %, as utilized in the Economic Outlook - December 2018 Update

Forecaster	Date of Forecast	End of Period or Average	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1
BMO Nesbitt Burns	14-Dec-18	Average	1.21	1.46	1.66	1.75	1.90	2.00	2.15	2.25
CIBC	17-Dec-18	End of Period	1.21	1.46	1.66	1.87	2.15	2.23	2.23	2.15
Desjardins	13-Dec-18	End of Period	1.21	1.46	1.66	1.72	1.93	2.13	2.25	2.40
Laurentian	25-Oct-18	End of Period	1.21	1.46	1.66	1.82	2.00	2.13	2.25	2.31
National Bank	1-Dec-18	End of Period	1.21	1.46	1.66	1.80	2.07	2.28	2.42	2.44
Royal Bank	7-Dec-18	End of Period	1.21	1.46	1.66	1.65	1.80	2.05	2.18	2.33
Scotiabank	7-Dec-18	End of Period	1.21	1.46	1.66	1.72	1.93	2.18	2.43	2.68
TD Bank	13-Dec-18	End of Period	1.21	1.46	1.66	1.82	2.07	2.19	2.32	2.44
IHS Global Insight	10-Dec-18	Average	1.21	1.46	1.66	1.83	2.01	2.26	2.51	2.76
Conference Board	14-Dec-18	Average	1.21	1.46	1.66	1.88	1.96	2.06	2.23	2.38

	2018/19	2019/20
EO 2018 - December	**1.55**	**2.20**

Note: In the case where source forecasts are provided as end of period, the 2018 Q4 end of period actual rate of 1.65% was averaged with the source forecasters' end of period rate for 2019 Q1 in order to approximate an average period 2019 Q1 forecast rate.

Table 5 – Canadian LT bond 10 Yr+ Rate %, as utilized in the Economic Outlook - December 2018 Update

Forecaster	Date of Forecast	End of Period or Average	2018 Q2	2018 Q3	2018 Q4	2019 Q1	2019 Q2	2019 Q3	2019 Q4	2020 Q1
BMO Nesbitt Burns	14-Dec-18	Average	2.33	2.29	2.37	2.28	2.39	2.53	2.63	2.73
CIBC	17-Dec-18	End of Period	2.33	2.29	2.37	2.33	2.54	2.61	2.59	2.55
Desjardins	13-Dec-18	End of Period	2.33	2.29	2.37	2.35	2.60	2.79	2.93	3.04
Laurentian	25-Oct-18	End of Period	2.33	2.29	2.37	2.45	2.73	2.80	2.88	2.93
National Bank	1-Dec-18	End of Period	2.33	2.29	2.37	2.27	2.42	2.59	2.83	2.98
Royal Bank	7-Dec-18	End of Period	2.33	2.29	2.37	2.36	2.66	2.86	2.93	3.00
Scotiabank	7-Dec-18	End of Period	2.33	2.29	2.37	2.26	2.41	2.63	2.78	2.84
TD Bank	13-Dec-18	End of Period	2.33	2.29	2.37	2.33	2.56	2.74	2.88	2.95
IHS Global Insight	10-Dec-18	Average	2.33	2.29	2.37	2.76	2.91	3.01	3.07	3.13
Conference Board	14-Dec-18	Average	2.33	2.29	2.37	2.80	3.15	3.50	3.68	3.79

	2018/19	2019/20
EO 2018 - December	**2.35**	**2.85**

Note: In the case where source forecasts are provided as end of period, the 2018 Q4 end of period actual rate of 2.19% (average of 2.11% for Canada 10 year and 2.27% for Canada 30 year) was averaged with the source forecasters' end of period rate for 2019 Q1 in order to approximate an average period 2019 Q1 forecast rate.

Copies of the publically available and private sector forecasts from the December 2018 survey are provided as an attachment to this response.

c) Please see the response part b above

d) With three-quarters of the 2018/19 fiscal year complete, any change to forecast interest rates in 2018/19 would only impact the last quarter (Jan/19 to Mar/19) and have minimal impacts to 2018/19 finance expense and therefore, net income. Table 6 below compares Manitoba Hydro's 2019/20 interest rate forecasts based on a consensus view at December 2018 and at December 2017.

Table 6 – Comparison of Forecast Interest Rates for fiscal year 2019/20

	Winter 2018	Winter 2017 (2019/20 Interim Budget)	Increase/ (Decrease)
MH Short Term Interest Rate*	2.20%	2.20%	0.00%
MH Long Term Interest Rate*	3.80%	4.00%	(0.20%)

*Not including the 1% Provincial Guarantee Fee

Figure 2.10 on page 26 of Manitoba Hydro's application shows that the 2019/20 Interim Budget net income could increase by approximately $15 million with short term and long term interest rates 1% below that forecasted. Compared to the Winter 2017 interest rate forecast, the Winter 2018 forecast shows no change to the forecast short term interest rate and a 20 basis points reduction to the long term interest rate. As a result, the 2019/20 Interim Budget net income would increase approximately $1 million to $3 million due to a reduction in finance expense.

Canadian Economic Outlook

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December 14, 2018

		2018				2019				2020							
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2017	2018	2019	2020
Production	**q/q % chng : a.r.**																
Real GDP (chain-weighted)		1.7	2.9	2.0	1.5	1.0	2.5	2.2	1.9	1.6	1.6	1.6	1.5	3.0	2.1	1.8	1.7
Final Sales		1.4	3.9	3.1	2.4	1.9	1.6	1.8	1.6	1.6	1.6	1.6	1.5	2.1	2.5	2.2	1.6
Final Domestic Demand		2.2	1.8	-0.1	1.8	2.1	1.7	1.8	1.5	1.6	1.6	1.6	1.5	3.1	2.5	1.6	1.6
Consumer Spending		1.5	2.3	1.2	1.6	2.1	1.6	1.6	1.4	1.4	1.4	1.4	1.4	3.6	2.2	1.7	1.4
Durables		1.4	0.6	-2.7	1.5	1.8	1.7	1.5	1.5	1.3	1.3	1.3	1.3	7.1	1.8	1.0	1.4
Nondurables		0.5	1.0	1.7	1.8	2.6	1.6	1.6	1.3	1.4	1.3	1.3	1.3	2.7	1.8	1.8	1.3
Services		2.0	3.3	1.4	1.6	1.9	1.6	1.6	1.4	1.5	1.5	1.5	1.5	3.3	2.6	1.7	1.5
Goverment Spending		2.3	1.2	1.9	2.5	2.2	1.8	2.0	2.0	1.8	1.8	1.8	1.8	2.7	3.1	2.0	1.9
Business Investment		13.0	1.0	-7.1	3.0	3.8	3.8	3.2	2.9	2.8	2.3	2.3	2.0	2.5	5.1	1.9	2.7
Non-residential Construction		5.7	0.3	-5.2	1.0	4.0	4.0	3.5	3.0	3.0	2.5	2.5	2.0	1.1	3.2	1.9	2.9
Machinery and Equipment		25.5	2.0	-9.8	6.0	3.5	3.5	2.8	2.8	2.5	2.0	2.0	2.0	4.7	8.0	2.0	2.5
Residential Construction		-7.9	-0.1	-5.9	0.0	0.0	0.0	0.5	0.0	1.0	1.0	1.0	1.0	2.4	-1.0	-0.7	0.7
Exports		2.3	13.0	0.9	2.7	2.1	2.2	2.2	2.2	2.0	2.0	2.0	2.0	1.1	3.2	2.7	2.1
Imports		4.7	5.9	-7.8	1.0	2.6	2.4	2.1	2.0	2.1	2.0	2.0	2.0	4.2	3.2	1.0	2.1
	2007$ blns (contribution in ppts : a.r.)																
Inventory Change		16.6	13.5	6.6	2.5	-2.5	1.9	4.0	5.6	5.6	5.6	5.6	5.6	17.6	9.8	2.2	5.6
Contribution to GDP Growth		0.1	-0.6	-1.3	-0.9	-1.0	0.8	0.4	0.3	0.0	0.0	0.0	0.0	0.8	-0.4	-0.4	0.2
Net Exports		-24.3	-14.0	1.0	3.7	2.8	2.5	2.6	2.8	2.7	2.7	2.7	2.7	-8.3	-8.4	2.7	2.7
Contribution to GDP Growth		-0.8	2.0	3.0	0.5	-0.2	-0.1	0.0	0.0	-0.1	0.0	0.0	0.0	-1.1	-0.1	0.5	0.0
	$ blns : a.r. (growth in q/q % chng : a.r.)																
Nominal GDP		2,190	2,215	2,242	2,238	2,257	2,283	2,306	2,328	2,348	2,368	2,389	2,409	2,138	2,221	2,294	2,379
Growth		2.9	4.6	5.0	-0.7	3.5	4.7	4.1	3.8	3.5	3.5	3.5	3.5	5.6	3.9	3.3	3.7
Real GDP	y/y % chng	2.3	1.9	2.1	2.0	1.8	1.7	1.8	1.9	2.0	1.8	1.6	1.5				
Inflation	**q/q % chng : a.r.**																
GDP Price Index		1.5	1.5	3.0	-2.3	2.5	2.1	1.9	1.9	1.9	1.9	1.9	1.9	2.6	1.8	1.4	1.9
CPI All Items		3.6	1.1	2.6	0.8	1.8	2.2	2.3	2.1	2.0	1.9	2.0	2.1	1.6	2.2	1.8	2.1
Ex. Food and Energy		2.7	0.8	2.5	1.9	2.4	1.9	2.0	2.1	2.1	1.9	2.0	2.1	1.6	1.9	2.0	2.0
Food Prices		0.9	1.5	3.3	2.2	2.7	2.2	1.8	2.1	2.0	2.1	1.8	2.1	0.0	1.7	2.3	2.0
Energy Prices		16.9	5.6	1.8	-13.9	-6.5	5.0	6.7	2.0	1.4	2.3	2.4	2.0	5.4	6.9	-2.1	2.7
Services		4.2	2.7	4.8	0.3	1.9	2.4	2.3	1.5	1.9	2.4	2.3	1.5	2.2	2.7	2.1	2.0
CPI All Items	y/y % chng	2.1	2.3	2.7	2.0	1.6	1.8	1.7	2.1	2.1	2.1	2.0	2.0				
CPIX8	y/y % chng	1.3	1.4	1.6	1.7	1.8	2.1	2.2	2.2	2.1	2.2	2.0	2.1	1.1	1.5	2.0	2.1
New Core CPIs	y/y % chng : avg.	1.9	1.9	2.0	2.0	2.0	2.1	2.2	2.2	2.1	2.2	2.0	2.1	1.5	2.0	2.1	2.1
Financial	**% : quarterly avg.**																
Overnight Rate		1.25	1.25	1.50	1.75	1.75	2.00	2.00	2.25	2.25	2.50	2.50	2.50	0.71	1.44	2.00	2.44
3-Month T-Bill		1.14	1.21	1.47	1.65	1.75	1.90	2.00	2.15	2.25	2.40	2.40	2.40	0.69	1.35	1.95	2.35
90-Day BAs		1.67	1.74	1.95	2.20	2.35	2.50	2.55	2.70	2.75	2.90	2.90	2.90	1.15	1.90	2.50	2.85
10-Year Bond Yield		2.24	2.28	2.28	2.35	2.20	2.30	2.45	2.55	2.65	2.65	2.60	2.50	1.78	2.30	2.35	2.60
10-Year BBB Corporate Spread	ppts	1.68	1.80	1.83	2.00	2.20	2.25	2.30	2.30	2.30	2.30	2.30	2.30	1.83	1.83	2.26	2.30
Canada/US Spread	**bps**																
90 Day		-44	-66	-61	-70	-73	-78	-90	-88	-96	-81	-77	-76	-26	-60	-82	-82
10 Year		-52	-64	-65	-71	-75	-74	-72	-70	-68	-67	-65	-63	-55	-63	-73	-66
Foreign Trade	**$ blns : a.r.** (share in % of GDP)																
Current Account Balance		-69.3	-66.7	-41.4	-56.7	-56.3	-56.7	-58.0	-58.9	-58.3	-57.1	-56.0	-54.6	-60.1	-58.5	-57.5	-56.5
Share of GDP		-3.2	-3.0	-1.8	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.4	-2.3	-2.3	-2.8	-2.6	-2.5	-2.4
Merchandise Balance		-35.0	-22.7	-6.9	-21.4	-19.8	-19.0	-19.1	-19.0	-19.4	-19.6	-19.8	-20.0	-24.6	-21.5	-19.2	-19.7
Non-Merchandise Balance		-34.3	-44.0	-34.5	-35.3	-36.5	-37.7	-38.9	-39.9	-38.9	-37.5	-36.1	-34.6	-35.5	-37.0	-38.3	-36.8
	quarterly avg.																
US$	US¢/C$	79.1	77.5	76.5	75.9	74.4	74.2	74.5	74.7	74.9	75.2	75.4	75.7	77.1	77.3	74.5	75.3
	C$/US$	1.265	1.291	1.307	1.317	1.343	1.347	1.343	1.339	1.334	1.330	1.326	1.321	1.298	1.295	1.343	1.328
Yen	¥/C$	85.7	84.6	85.3	85.8	83.7	83.0	82.7	82.4	82.2	82.1	82.0	81.9	86.5	85.3	82.9	82.0
Euro	C$/€	1.55	1.54	1.52	1.50	1.53	1.52	1.53	1.55	1.55	1.55	1.56	1.56	1.46	1.53	1.53	1.55
Incomes	**y/y % chng**																
Corporate Profits Before Tax		-3.6	5.6	18.8	13.5	17.3	13.3	7.7	8.9	7.6	6.1	4.8	3.5	34.0	8.4	11.6	5.5
Corporate Profits After Tax		-2.2	1.6	16.9	3.0	8.2	7.7	5.8	8.9	7.6	6.1	4.8	3.5	15.8	4.5	7.6	5.5
Personal Income		5.3	4.7	3.9	2.3	2.5	2.7	3.0	3.9	4.0	3.8	3.6	3.5	4.6	4.0	3.0	3.7
Real Disposable Income		3.6	2.8	1.1	0.4	1.2	1.1	1.3	1.8	2.0	1.7	1.6	1.5	3.4	1.9	1.4	1.7
Savings Rate	% : quarterly avg.	1.3	1.0	0.8	0.3	0.0	0.1	0.2	0.3	0.4	0.4	0.5	0.6	1.5	0.9	0.2	0.5
Other Indicators	**quarterly avg.** (000s and mlns are a.r.)																
Unemployment Rate	percent	5.8	5.9	5.9	5.7	5.7	5.6	5.6	5.5	5.5	5.5	5.6	5.6	6.3	5.8	5.6	5.6
Housing Starts	000s	225	219	197	211	210	207	204	200	200	200	200	200	220	213	205	200
Existing Home Sales	y/y % chng	-14.8	-13.8	-4.0	-12.2	0.0	3.4	-1.6	0.4	2.2	2.3	1.8	1.8	-4.5	-10.9	0.5	2.0
MLS Home Price Index	y/y % chng	5.7	0.9	2.3	1.8	-0.3	-0.5	1.0	2.1	2.2	1.8	1.9	2.2	13.2	2.7	0.5	2.0
Motor Vehicle Sales	mlns	2.13	2.04	2.02	2.00	1.96	1.95	1.95	1.95	1.92	1.90	1.90	1.90	2.07	2.05	1.95	1.90
	q/q % chng : a.r.																
Employment Growth		0.1	0.7	1.3	1.9	0.9	1.1	1.1	1.0	0.5	0.4	0.5	0.9	1.9	1.3	1.2	0.7
Industrial Production		4.0	3.2	3.0	-1.7	-2.0	1.8	2.2	1.8	2.4	1.8	1.6	1.6	4.9	2.5	0.5	2.0
Federal Budget Balance	% of FY GDP													-0.9	-0.8	-0.9	-0.8

Please refer to page 2 for Important Disclosures

United States Economic Outlook

BMO Capital Markets
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Our key forecasts for the U.S. economy — **December 14, 2018**

					2018				2019				2020				
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2017	2018	2019	2020
Production	**q/q % chng : a.r.**																
Real GDP (chain-weighted)		2.2	4.2	3.5	2.6	1.9	2.4	2.0	1.9	1.8	1.6	1.4	1.3	2.2	2.9	2.4	1.7
Final Sales		1.9	5.4	1.2	2.8	2.4	2.1	1.9	1.8	1.8	1.6	1.3	1.3	2.2	2.8	2.4	1.7
Final Domestic Demand		1.9	4.0	3.1	3.3	2.6	2.3	2.1	1.9	1.9	1.7	1.4	1.4	2.5	3.0	2.7	1.8
Consumer Spending		0.5	3.8	3.6	3.2	2.4	2.3	2.1	2.0	2.1	1.8	1.4	1.4	2.5	2.7	2.7	1.9
Durables		-2.0	8.6	3.9	3.0	2.0	2.0	1.8	1.7	1.6	1.6	1.4	1.3	6.8	5.5	2.8	1.6
Nondurables		0.1	4.0	5.3	4.0	2.4	2.3	2.0	2.0	2.0	1.4	1.4	1.3	2.1	3.0	3.1	1.8
Services		1.0	3.0	3.1	3.0	2.5	2.4	2.2	2.1	2.2	2.0	1.4	1.4	2.0	2.2	2.6	2.0
Goverment Spending		1.5	2.5	2.6	4.2	3.1	2.1	1.9	1.5	1.0	1.1	1.1	1.1	-0.1	1.8	2.7	1.3
Business Investment		11.5	8.7	2.5	3.9	3.0	2.6	2.1	2.0	2.0	1.9	1.8	1.7	5.3	6.8	3.2	2.0
Non-residential Construction		13.9	14.5	-1.7	2.0	3.0	2.2	1.9	1.8	1.8	1.6	1.5	1.4	4.6	5.6	2.5	1.7
Equipment		8.5	4.6	3.5	3.5	3.0	2.5	1.9	1.8	1.8	1.7	1.6	1.5	6.1	7.2	2.9	1.8
Intellectual Property		14.1	10.5	4.3	6.0	3.0	3.0	2.4	2.3	2.3	2.3	2.2	2.2	4.6	7.1	4.0	2.3
Residential Construction		-3.4	-1.3	-2.6	-3.0	1.0	1.7	1.7	1.7	1.6	1.6	1.6	1.6	3.3	-0.1	-0.1	1.6
Exports		3.6	9.3	-4.4	4.0	2.4	2.2	2.1	2.1	2.0	2.0	2.0	2.0	3.0	4.2	2.1	2.0
Imports		3.0	-0.6	9.2	6.1	3.2	3.1	3.0	2.7	2.4	2.3	2.2	2.1	4.6	4.8	4.2	2.5
	2009$ blns : a.r. (contribution in ppts : a.r.)																
Inventory Change		30.3	-36.8	86.6	76.0	51.0	61.0	65.0	68.0	68.0	68.0	69.0	70.0	21.5	37.9	61.3	68.8
Contribution to GDP Growth		0.3	-1.2	2.3	-0.2	-0.5	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0
Net Exports		-902.3	-841.0	-945.8	-973.0	-985.7	-999.0	-1012.2	-1022.8	-1031.5	-1039.3	-1046.3	-1052.4	-858.7	-915.5	-1004.9	-1042.3
Contribution to GDP Growth		0.0	1.2	-1.9	-0.6	-0.3	-0.3	-0.3	-0.2	-0.2	-0.2	-0.1	-0.1	-0.3	-0.3	-0.5	-0.2
	$ blns : a.r. (growth in q/q % chng : a.r.)																
Nominal GDP		20,041	20,412	20,660	20,912	21,103	21,337	21,549	21,758	21,966	22,156	22,337	22,518	19,485	20,506	21,437	22,244
Growth		4.3	7.6	5.0	5.0	3.7	4.5	4.0	3.9	3.9	3.5	3.3	3.3	4.2	5.2	4.5	3.8
Real GDP	y/y % chng	2.6	2.9	3.0	3.1	3.0	2.6	2.2	2.0	2.0	1.8	1.7	1.5				
Inflation	**q/q % chng : a.r.**																
GDP Price Index		2.0	3.0	1.7	2.4	1.8	2.1	2.0	2.0	2.1	1.9	1.9	1.9	1.9	2.3	2.1	2.0
Core PCE Deflator		2.2	2.1	1.5	1.7	2.9	2.2	2.1	2.2	2.3	1.9	2.0	2.0	1.6	1.9	2.2	2.1
CPI All Items		3.5	1.7	2.0	1.8	1.9	2.2	2.1	2.1	2.1	1.8	1.9	1.9	2.1	2.4	2.0	2.0
Ex. Food and Energy		3.0	1.8	2.0	2.1	2.9	2.2	2.1	2.2	2.3	1.9	2.0	2.0	1.8	2.1	2.3	2.1
Food Prices		1.5	1.7	1.4	0.7	2.2	2.2	2.0	2.0	2.0	2.0	2.0	2.0	0.9	1.4	1.8	2.0
Energy Prices		12.7	0.2	2.8	1.3	-8.3	2.8	2.7	1.3	1.2	1.2	1.2	1.2	8.0	7.5	-0.6	1.5
Services		3.2	2.4	2.5	2.6	2.2	2.2	2.0	2.0	2.0	2.0	2.0	2.0	2.7	2.8	2.3	2.0
CPI All Items	y/y % chng	2.3	2.6	2.6	2.2	1.8	2.0	2.0	2.1	2.1	2.0	2.0	2.0				
Ex. Food and Energy	y/y % chng	1.9	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.2	2.1	2.1	2.0				
Core PCE Deflator	y/y % chng	1.7	1.9	2.0	1.9	2.0	2.1	2.2	2.3	2.2	2.1	2.1	2.0				
Financial	**% : quarterly avg.**																
Fed Funds Rate		1.46	1.71	1.96	2.21	2.38	2.54	2.71	2.88	3.13	3.13	3.13	3.13	1.00	1.83	2.63	3.13
90-Day T-Bill		1.58	1.87	2.08	2.35	2.45	2.70	2.90	3.05	3.20	3.20	3.15	3.15	0.95	1.95	2.75	3.20
3-Month Libor		1.91	2.34	2.34	2.60	2.80	3.00	3.15	3.30	3.50	3.50	3.50	3.50	1.26	2.30	3.05	3.50
10-Year Bond Yield		2.76	2.92	2.93	3.05	2.95	3.05	3.15	3.25	3.35	3.35	3.25	3.15	2.33	2.90	3.10	3.25
10-Year BBB Corporate Spread	ppts	1.40	1.56	1.61	1.75	1.95	2.10	2.20	2.30	2.35	2.35	2.35	2.35	1.61	1.58	2.14	2.35
Foreign Trade	**$ blns : a.r.** (share in % of GDP)																
Current Account Balance		-487	-406	-530	-495	-521	-537	-553	-567	-580	-587	-594	-600	-449	-480	-545	-590
Share of GDP		-2.4	-2.0	-2.6	-2.4	-2.5	-2.5	-2.6	-2.6	-2.6	-2.7	-2.7	-2.7	-2.3	-2.3	-2.5	-2.7
Merchandise Balance		-883	-813	-933	-916	-938	-953	-969	-983	-995	-1007	-1019	-1029	-807	-886	-961	-1013
Non-Merchandise Balance		396	407	403	421	417	416	416	415	416	420	425	429	358	407	416	422
	quarterly avg.																
Yen	¥/US$	108	109	112	113	113	112	111	110	110	109	109	108	112	110	111	109
Euro	US$/€	1.23	1.19	1.16	1.14	1.14	1.13	1.14	1.16	1.16	1.17	1.17	1.18	1.13	1.18	1.14	1.17
Pound	US$/£	1.39	1.36	1.30	1.28	1.24	1.23	1.26	1.29	1.31	1.32	1.33	1.35	1.29	1.34	1.26	1.33
Trade-Wt. Dollar (broad)	Jan '97=100	117.6	121.0	125.1	127.7	129.2	129.8	128.8	127.4	126.7	126.3	125.8	125.4	122.1	122.9	128.8	126.0
Commodity Prices	**quarterly avg.**																
WTI Spot	US$/bbl	62.9	67.9	69.7	60.6	58.0	62.7	64.3	63.0	62.0	62.0	62.0	62.0	50.9	65.3	62.0	62.0
Henry Hub Spot	US$/mmbtu	3.1	2.9	2.9	3.7	3.5	3.0	3.1	3.2	3.3	3.3	3.3	3.3	3.0	3.1	3.2	3.3
Incomes	**y/y % chng**																
Pre-Tax Profits with IVA and CCA		5.9	7.3	10.3	9.1	8.8	6.8	4.3	4.0	4.1	3.8	3.7	3.5	3.2	8.2	5.9	3.8
Personal Income		4.3	4.5	4.4	4.2	3.9	4.0	4.0	3.8	3.7	3.7	3.6	3.6	4.4	4.3	3.9	3.7
Real Disposable Income		2.8	2.7	2.7	2.9	2.4	2.3	2.1	1.8	1.6	1.6	1.6	1.6	2.6	2.8	2.1	1.6
Savings Rate	% : quarterly avg.	7.2	6.7	6.3	6.3	6.2	6.1	6.0	5.9	5.7	5.7	5.7	5.8	6.7	6.6	6.0	5.7
Other Indicators	**quarterly avg.** (mlns are a.r.)																
Unemployment Rate	percent	4.1	3.9	3.8	3.7	3.6	3.5	3.5	3.5	3.5	3.5	3.6	3.7	4.4	3.9	3.5	3.6
Housing Starts	mlns	1.32	1.26	1.22	1.24	1.26	1.24	1.23	1.21	1.21	1.22	1.22	1.22	1.21	1.26	1.24	1.22
Existing Home Sales	mlns	5.51	5.41	5.27	5.31	5.39	5.36	5.34	5.33	5.34	5.35	5.36	5.37	5.54	5.38	5.36	5.36
Home Prices (Case-Shiller)	y/y % chng	6.6	6.5	5.6	4.5	3.3	3.2	3.6	3.5	3.3	3.2	3.1	3.0	5.9	5.8	3.4	3.1
Motor Vehicle Sales	mlns	17.2	17.2	17.0	17.4	16.7	16.5	16.4	16.2	16.1	16.0	16.0	16.0	17.2	17.2	16.4	16.0
	q/q % chng : a.r.																
Civilian Employment		2.7	1.2	1.1	2.5	1.2	1.0	0.9	0.9	0.8	0.6	0.5	0.5	1.3	1.6	1.3	0.7
Industrial Production		2.5	5.2	4.7	2.7	3.1	2.5	2.4	2.2	1.9	1.6	1.6	1.6	1.6	3.9	3.1	1.9
CBO Budget Deficit	% of GDP													-3.5	-4.0	-4.6	-4.6

Shaded values represent forecasts

Please refer to page 2 for Important Disclosures

Rates Scenario

BMO Capital Markets

December 17, 2018

Interest Rate Forecasts

Percent (averages)

	Actual 2018 Nov	Forecasts 2018 Dec	2019 Jan	Feb	Mar	Apr	May	Jun	2019 Q3	Q4	2020 Q1
Cdn. Yield Curve											
Overnight	1.75	1.75[1]	1.75	1.75	1.75	2.00	2.00	2.00	2.00	2.25	2.25
3 month	1.71	1.65	1.65	1.75	1.80	1.90	1.90	1.90	2.00	2.15	2.25
6 month	1.90	1.80	1.90	1.95	2.00	2.10	2.10	2.10	2.20	2.35	2.45
1 year	2.13	2.00	2.05	2.10	2.15	2.20	2.20	2.25	2.30	2.40	2.50
2 year	2.27	2.05	2.10	2.15	2.15	2.20	2.25	2.30	2.35	2.45	2.55
3 year	2.28	2.05	2.10	2.15	2.15	2.20	2.25	2.30	2.35	2.45	2.55
5 year	2.34	2.05	2.10	2.15	2.20	2.20	2.25	2.30	2.35	2.45	2.60
7 year	2.36	2.10	2.15	2.15	2.20	2.25	2.25	2.30	2.40	2.50	2.60
10 year	2.41	2.15	2.15	2.20	2.25	2.30	2.30	2.35	2.45	2.55	2.65
30 year	2.46	2.30	2.35	2.35	2.40	2.45	2.50	2.50	2.60	2.70	2.80
1m BA	2.10	2.20	2.20	2.25	2.35	2.40	2.40	2.40	2.45	2.60	2.65
3m BA	2.22	2.25	2.25	2.35	2.40	2.50	2.50	2.50	2.55	2.70	2.75
6m BA	2.34	2.35	2.45	2.45	2.50	2.55	2.55	2.55	2.70	2.80	2.90
12m BA	2.56	2.55	2.60	2.65	2.70	2.70	2.75	2.75	2.80	2.85	3.00
Prime Rate	3.95	3.95	3.95	3.95	3.95	4.20	4.20	4.20	4.20	4.45	4.45
U.S. Yield Curve											
Fed funds	2.13	2.38	2.38	2.38	2.38	2.38	2.63	2.63	2.88	2.88	3.13
3 month	2.37	2.40	2.40	2.40	2.50	2.60	2.70	2.70	2.90	3.05	3.20
6 month	2.52	2.55	2.55	2.60	2.70	2.75	2.80	2.85	2.95	3.15	3.25
1 year	2.70	2.70	2.70	2.75	2.80	2.85	2.90	2.95	3.05	3.15	3.30
2 year	2.86	2.75	2.80	2.85	2.85	2.90	2.95	3.00	3.05	3.20	3.30
3 year	2.91	2.75	2.80	2.85	2.85	2.90	2.95	3.00	3.10	3.20	3.30
5 year	2.95	2.80	2.80	2.85	2.90	2.90	2.95	3.00	3.10	3.20	3.30
7 year	3.04	2.85	2.85	2.90	2.90	2.95	3.00	3.05	3.10	3.20	3.30
10 year	3.12	2.90	2.95	2.95	3.00	3.05	3.05	3.10	3.15	3.25	3.35
30 year	3.36	3.15	3.20	3.20	3.25	3.30	3.30	3.35	3.40	3.50	3.60
1m LIBOR	2.32	2.45	2.45	2.45	2.55	2.60	2.70	2.70	2.90	3.10	3.25
3m LIBOR	2.65	2.80	2.80	2.80	2.85	2.95	3.00	3.00	3.15	3.30	3.50
6m LIBOR	2.86	2.90	2.90	2.85	2.95	3.05	3.15	3.10	3.35	3.45	3.65
12m LIBOR	3.12	3.10	3.15	3.05	3.15	3.25	3.35	3.30	3.50	3.55	3.75
Prime Rate	5.25	5.50	5.50	5.50	5.50	5.50	5.75	5.75	5.85	6.00	6.25
Other G7 Yields											
ECB Refi	0.00	0.00[1]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
10yr Bund	0.38	0.25	0.30	0.35	0.35	0.40	0.45	0.50	0.55	0.70	0.70
BoE Repo	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	1.00	1.00	1.00
10yr Gilt	1.44	1.35	1.40	1.40	1.45	1.45	1.50	1.50	1.55	1.65	1.65
BoJ O/N	-0.06	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	-0.05	0.00	0.00
10yr JGB	0.10	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16

[1] actual value for December 2018

MARKET CALL

- We were among the most dovish forecasters for North American central banks, but markets have moved in a hurry to share that view, or even take it further. Stateside, the Fed no longer seems to be at risk of blindly overshooting the neutral rate, and we trimmed our 2019 forecast to only one further hike after this week's likely move, while leaving a small cut in place for 2020, as a signpost that we still see a mid-cycle ease when fiscal policy tightens. We also trimmed our peak Treasury yields as the Fed's downgraded view on where neutral sits will also impact market views.

- We're sticking to our prior call for two further Bank of Canada hikes, hitting a peak rate of 2.25% in the first half, but still at that level through 2020, a long way from the roughly 3% rate that the central bank saw as neutral only two months ago. Frankly, we're less assured about the timing of coming hikes, as we're publishing ahead of key indicators for October, and we'll also need to see at least a partial recovery in global oil prices to get the first of the hikes. Given those clouds, we see more risk of only one hike than three moves from here.

- If Poloz manages to squeeze in a hike while the Fed is on hold, it will also be because oil prices and other data have also turned a bit brighter. That would support a temporary rebound in the Canadian dollar, but one we don't see as sticking. Canada's track record on exports, and the need for improvement on that front as housing slows, suggests that we need to be on the topside of 1.30 to be competitive.

INTEREST & FOREIGN EXCHANGE RATES

		2018	2019				2020			
END OF PERIOD:		**14-Dec**	**Mar**	**Jun**	**Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
CDA	Overnight target rate	1.75	2.00	2.25	2.25	2.25	2.25	2.25	2.25	2.25
	98-Day Treasury Bills	1.63	2.10	2.20	2.25	2.20	2.10	2.05	2.00	1.95
	2-Year Gov't Bond	2.02	2.50	2.55	2.40	2.30	2.25	2.20	2.15	2.05
	10-Year Gov't Bond	2.11	2.50	2.65	2.65	2.50	2.45	2.40	2.35	2.20
	30-Year Gov't Bond	2.28	2.45	2.55	2.60	2.60	2.65	2.65	2.55	2.50
U.S.	Federal Funds Rate	2.125	2.375	2.625	2.625	2.625	2.625	2.375	2.375	2.375
	91-Day Treasury Bills	2.42	2.35	2.65	2.70	2.80	2.60	2.40	2.25	2.25
	2-Year Gov't Note	2.73	3.00	3.25	3.20	3.10	2.85	2.65	2.55	2.50
	10-Year Gov't Note	2.88	3.15	3.35	3.35	3.25	3.10	3.05	2.90	2.80
	30-Year Gov't Bond	3.14	3.25	3.40	3.45	3.45	3.45	3.25	3.10	3.00
Canada - US T-Bill Spread		-0.79	-0.25	-0.45	-0.45	-0.60	-0.50	-0.35	-0.25	-0.30
Canada - US 10-Year Bond Spread		-0.78	-0.65	-0.70	-0.70	-0.75	-0.65	-0.65	-0.55	-0.60
Canada Yield Curve (10-Year — 2-Year)		0.09	0.00	0.10	0.25	0.20	0.20	0.20	0.20	0.15
US Yield Curve (10-Year — 2-Year)		0.15	0.15	0.10	0.15	0.15	0.25	0.40	0.35	0.30
EXCHANGE RATES	CADUSD	0.75	0.77	0.76	0.76	0.75	0.75	0.76	0.76	0.77
	USDCAD	1.34	1.30	1.31	1.32	1.34	1.33	1.32	1.31	1.30
	USDJPY	113	112	110	108	106	105	104	102	100
	EURUSD	1.13	1.15	1.18	1.20	1.22	1.25	1.26	1.25	1.24
	GBPUSD	1.26	1.32	1.37	1.41	1.44	1.45	1.46	1.45	1.44
	AUDUSD	0.72	0.74	0.75	0.76	0.77	0.78	0.79	0.79	0.80
	USDCHF	1.00	0.98	0.95	0.95	0.93	0.92	0.92	0.93	0.94
	USDBRL	3.90	3.90	3.70	3.90	4.10	4.00	3.95	3.90	3.80
	USDMXN	20.3	20.2	19.7	19.7	20.1	20.3	20.3	20.7	21.0

TABLE 1
Key interest rates

END OF PERIOD IN %	2018 Q1	2018 Q2	2018 Q3	2018 Q4f	2019 Q1f	2019 Q2f	2019 Q3f	2019 Q4f	2020 Q1f	2020 Q2f	2020 Q3f	2020 Q4f
United States												
Federal funds	1.75	2.00	2.25	2.50	2.75	2.75	3.00	3.25	3.50	3.50	3.50	3.25
Canada												
Overnight funds	1.25	1.25	1.50	1.75	1.75	2.00	2.25	2.25	2.50	2.50	2.50	2.25
Zone euro												
Refinancing rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.25	0.25	0.50	0.50
United Kingdom												
Base rate	0.50	0.50	0.75	0.75	0.75	0.75	1.00	1.00	1.25	1.25	1.50	1.50
Japan												
Main key rate	-0.10	-0.10	-0.10	-0.10	-0.10	-0.10	-0.10	-0.10	-0.10	0.00	0.00	0.00

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

TABLE 2
Fixed income market

END OF PERIOD IN %	2018 Q1	2018 Q2	2018 Q3	2018 Q4f	2019 Q1f	2019 Q2f	2019 Q3f	2019 Q4f	2020 Q1f	2020 Q2f	2020 Q3f	2020 Q4f
UNITED STATES												
Treasury bills												
3-month	1.73	1.93	2.19	2.45	2.60	2.70	2.95	3.20	3.30	3.30	3.20	2.90
Federal bonds												
2-year	2.27	2.53	2.82	2.90	3.05	3.10	3.25	3.40	3.50	3.50	3.30	3.00
5-year	2.55	2.73	2.95	2.95	3.15	3.20	3.35	3.50	3.60	3.60	3.35	3.00
10-year	2.75	2.86	3.06	3.05	3.25	3.35	3.50	3.60	3.70	3.70	3.45	3.15
30-year	2.97	2.99	3.21	3.30	3.45	3.55	3.70	3.75	3.80	3.80	3.60	3.30
Yield curve slopes												
5-year - 3-month	0.82	0.80	0.76	0.50	0.55	0.50	0.40	0.30	0.30	0.30	0.15	0.10
10-year - 2-year	0.47	0.33	0.24	0.15	0.20	0.25	0.25	0.20	0.20	0.20	0.15	0.15
30-year - 3-month	1.24	1.06	1.02	0.85	0.85	0.85	0.75	0.55	0.50	0.50	0.40	0.40
CANADA												
Treasury bills												
3-month	1.10	1.26	1.59	1.70	1.80	2.05	2.20	2.30	2.50	2.50	2.45	2.15
Federal bonds												
2-year	1.77	1.91	2.21	2.10	2.25	2.40	2.50	2.65	2.80	2.80	2.60	2.30
5-year	1.96	2.06	2.33	2.15	2.35	2.50	2.65	2.80	2.90	2.90	2.65	2.30
10-year	2.09	2.17	2.42	2.20	2.45	2.65	2.80	2.90	3.05	3.05	2.80	2.55
30-year	2.23	2.20	2.41	2.35	2.55	2.75	2.95	3.05	3.15	3.15	2.95	2.70
Yield curve slopes												
5-year - 3-month	0.86	0.80	0.74	0.45	0.55	0.45	0.45	0.50	0.40	0.40	0.20	0.15
10-year - 2-year	0.32	0.26	0.21	0.10	0.20	0.25	0.30	0.25	0.25	0.25	0.20	0.25
30-year - 3-month	1.13	0.94	0.82	0.65	0.75	0.70	0.75	0.75	0.65	0.65	0.50	0.55
Yield spreads (Canada—United States)												
3-month	-0.63	-0.67	-0.60	-0.75	-0.80	-0.65	-0.75	-0.90	-0.80	-0.80	-0.75	-0.75
2-year	-0.50	-0.62	-0.61	-0.80	-0.80	-0.70	-0.75	-0.75	-0.70	-0.70	-0.70	-0.70
5-year	-0.59	-0.67	-0.62	-0.80	-0.80	-0.70	-0.70	-0.70	-0.70	-0.70	-0.70	-0.70
10-year	-0.66	-0.69	-0.64	-0.85	-0.80	-0.70	-0.70	-0.70	-0.65	-0.65	-0.65	-0.60
30-year	-0.74	-0.79	-0.80	-0.95	-0.90	-0.80	-0.75	-0.70	-0.65	-0.65	-0.65	-0.60

f: forecasts
Sources: Datastream and Desjardins, Economic Studies

Laurentian Bank Securities

ECONOMIC RESEARCH AND STRATEGY

Forecasts Tables

Canadian Economic Outlook

	(q/q saar)					annual average				Q4/Q4	
	2017Q4	2018Q1	2018Q2	2018Q3	2018Q4	2017	2018	2019	2020	2017	2018
Real GDP	1.7	1.4	2.9	2.2	2.1	3.0	2.1	2.1	1.9	3.0	2.2
Consumer Expenditure	2.2	1.0	2.6	1.2	1.7	3.5	2.0	1.8	1.7	3.4	1.6
Business Investment	7.4	11.2	1.7	9.8	4.9	2.5	7.2	5.4	5.0	8.6	6.8
Non-residential structures	4.0	8.2	2.2	3.0	5.0	0.7	5.4	5.3	6.2	6.4	4.6
Machinery and equipment	14.5	16.4	1.4	12.0	5.0	6.0	9.5	4.9	3.8	12.9	8.5
Residential Investment	13.5	-10.5	1.1	2.0	3.0	2.9	0.1	1.3	1.0	4.6	-1.2
Government Spending	4.5	2.8	1.0	2.7	2.7	2.6	2.9	2.1	2.1	3.3	2.3
Exports	3.9	2.4	12.4	1.3	4.7	1.0	3.1	3.0	2.1	0.5	5.1
Imports	7.7	4.3	6.5	-7.1	5.2	3.6	3.4	2.2	2.1	6.9	2.0
Total CPI Inflation *	1.8	2.1	2.3	2.7	2.4	1.6	2.4	2.1	2.0	1.8	2.4
Unemployment rate (%)*	6.0	5.8	5.9	5.9	5.9	6.3	5.9	5.8	5.7	--	--
Employment	2.6	0.1	4.1	1.3	0.8	1.9	1.2	0.9	0.7	2.1	0.7
Housing Starts (in 000s)*	229	225	219	196	210	220	213	205	200	--	--
Res. Transactions (units, 000s)**	132	115	111	118	--	516	462	494	515	--	--
Res. Housing Prices (yoy %)	9.2	7.6	4.3	1.8	--	12.1	--	--	--	--	--
Nominal GDP	6.3	3.1	5.1	3.6	2.8	5.4	4.0	3.7	3.9	4.9	3.7

*Average for the period. **total for the period
Updated: October 2018

Financial Forecasts

	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4	19Q1	19Q2	19Q3	19Q4	20Q4
Canada													
Overnight Rate Target	**0.50**	**0.50**	**1.00**	**1.00**	**1.25**	**1.25**	**1.50**	**1.75**	**2.00**	**2.00**	**2.25**	**2.25**	**2.75**
3-Month Treasury Bills	0.53	0.71	1.00	1.05	1.10	1.26	1.58	1.75	2.00	2.00	2.25	2.25	2.75
2-Year Bond	0.75	1.09	1.50	1.67	1.77	1.92	2.21	2.35	2.50	2.50	2.70	2.70	3.05
5-Year Bond	1.11	1.39	1.75	1.86	1.96	2.06	2.33	2.45	2.60	2.60	2.75	2.75	2.85
10-Year Bond	1.62	1.77	2.09	2.04	2.09	2.17	2.42	2.55	2.70	2.75	2.85	2.90	3.10
30-Year Bond	2.30	2.14	2.47	2.27	2.23	2.20	2.42	2.50	2.70	2.75	2.85	2.90	3.15
United States													
Federal Funds Rate Target*	**1.000**	**1.250**	**1.250**	**1.500**	**1.750**	**2.000**	**2.250**	**2.500**	**2.750**	**3.000**	**3.000**	**3.000**	**3.250**
3-Month Treasury Bills	0.75	1.01	1.04	1.37	1.70	1.89	2.15	2.40	2.70	3.00	3.05	3.05	3.30
2-Year Bond	1.24	1.37	1.49	1.88	2.27	2.53	2.82	3.00	3.25	3.40	3.40	3.40	3.50
5-Year Bond	1.92	1.88	1.92	2.19	2.56	2.73	2.95	3.15	3.40	3.50	3.50	3.50	3.60
10-Year Bond	2.40	2.30	2.33	2.41	2.75	2.86	3.06	3.20	3.50	3.70	3.70	3.70	3.75
30-Year Bond	3.02	2.84	2.86	2.74	2.97	2.99	3.21	3.40	3.60	3.80	3.80	3.80	3.90
Canadian Dollar (US$/C$)	**0.75**	**0.77**	**0.80**	**0.80**	**0.78**	**0.76**	**0.77**	**0.80**	**0.81**	**0.81**	**0.81**	**0.81**	**0.82**
S&P 500 Index	2363	2423	2519	2674	2641	2718	2914	2800	2850	2900	2950	3000	3150
TSX Index	15548	15182	15635	16209	15367	16278	16073	16500	17250	18000	18500	19000	20000
Oil WTI (US$/barrel)	50.5	46	52	60	65	74	73	67	67	67	67	67	67

Quarter-end data
Updated: October 2018 * Upper bound of the target range for the Fed funds rate.

LAURENTIAN BANK SECURITIES

Monthly Economic Monitor

NATIONAL BANK OF CANADA FINANCIAL MARKETS

United States
Economic Forecast

(Annual % change)*	2016	2017	2018	2019	2020	Q4/Q4 2018	Q4/Q4 2019	Q4/Q4 2020
Gross domestic product (2012 $)	1.6	2.2	2.9	2.3	1.9	3.0	1.8	1.8
Consumption	2.7	2.5	2.6	2.3	1.9	2.6	1.8	1.8
Residential construction	6.5	3.3	0.1	0.5	1.4	(1.8)	1.5	1.5
Business investment	0.5	5.3	6.6	2.0	1.4	5.7	1.6	1.7
Government expenditures	1.4	(0.1)	1.7	2.3	1.6	2.4	2.0	1.2
Exports	(0.1)	3.0	4.2	1.8	0.9	3.2	1.2	1.0
Imports	1.9	4.6	4.5	2.2	1.1	3.3	1.2	1.0
Change in inventories (bil. $)	23.4	22.5	36.7	39.8	25.1	66.5	32.7	23.8
Domestic demand	2.3	2.5	2.9	2.2	1.7	2.8	1.8	1.7
Real disposable income	1.7	2.6	2.7	1.8	1.7	2.6	1.7	1.7
Household employment	1.7	1.3	1.5	1.1	1.0	1.5	1.0	0.9
Unemployment rate	4.9	4.4	3.9	3.6	3.5	3.8	3.6	3.5
Inflation	1.3	2.1	2.4	2.3	2.4	2.3	2.6	2.3
Before-tax profits	(1.1)	3.2	8.3	6.6	4.1	9.6	4.5	3.7
Federal balance (unified budget, bil. $)	(587.0)	(666.0)	(779.0)	(981.0)	(1,020.0)	...	...	...
Current account (bil. $)	(432.9)	(449.1)	(434.4)	(436.8)	(437.0)	...	...	...

** or as noted*

Financial Forecast**

	Current 12-05-18	Q1 2019	Q2 2019	Q3 2019	Q4 2019	2018	2019	2020
Fed Fund Target Rate	2.25	2.50	2.75	3.00	3.00	2.50	3.00	2.75
3 month Treasury bills	2.38	2.46	2.72	2.93	2.93	2.45	2.93	2.72
Treasury yield curve								
2-Year	2.80	2.93	2.99	3.19	3.25	2.87	3.25	2.71
5-Year	2.79	3.06	3.11	3.33	3.36	2.85	3.36	3.00
10-Year	2.91	3.21	3.31	3.46	3.48	3.00	3.48	3.24
30-Year	3.16	3.41	3.54	3.68	3.69	3.39	3.69	3.44
Exchange rates								
U.S.$/Euro	1.13	1.15	1.19	1.22	1.23	1.15	1.23	1.23
YEN/U.S.$	113	114	115	115	113	114	113	113

*** end of period*

Quarterly pattern

	Q1 2018 actual	Q2 2018 actual	Q3 2018 actual	Q4 2018 forecast	Q1 2019 forecast	Q2 2019 forecast	Q3 2019 forecast	Q4 2019 forecast
Real GDP growth (q/q % chg. saar)	2.2	4.2	3.5	2.3	1.7	2.0	1.9	1.6
CPI (y/y % chg.)	2.3	2.6	2.6	2.3	1.9	2.3	2.5	2.6
CPI ex. food and energy (y/y % chg.)	1.9	2.2	2.2	2.2	2.1	2.3	2.5	2.6
Unemployment rate (%)	4.1	3.9	3.8	3.8	3.7	3.7	3.6	3.6

National Bank Financial

Monthly Economic Monitor

NATIONAL BANK OF CANADA FINANCIAL MARKETS

Canada
Economic Forecast

(Annual % change)*	2016	2017	2018	2019	2020	Q4/Q4 2018	Q4/Q4 2019	Q4/Q4 2020
Gross domestic product (2012 $)	1.1	3.0	2.1	1.8	1.7	2.1	1.8	1.5
Consumption	2.1	3.6	2.2	1.5	1.2	1.7	1.4	1.0
Residential construction	3.5	2.4	(0.9)	(1.5)	(1.9)	(2.9)	(2.0)	(1.8)
Business investment	(9.9)	2.5	5.0	1.0	3.7	1.9	2.9	3.2
Government expenditures	1.2	2.7	3.0	2.0	1.7	1.7	2.3	1.2
Exports	1.3	1.1	3.3	4.1	3.1	4.8	3.7	3.5
Imports	(0.0)	4.2	3.2	1.6	2.1	0.8	3.0	2.0
Change in inventories (millions $)	2,291	17,582	10,025	1,166	1,316	3,362	658	957
Domestic demand	0.6	3.1	2.5	1.4	1.4	1.4	1.6	1.1
Real disposable income	(0.7)	3.4	2.1	1.6	1.5	0.9	1.6	1.5
Employment	0.7	1.9	1.2	0.9	0.8	0.7	0.8	0.7
Unemployment rate	7.0	6.3	5.9	5.7	5.7	5.8	5.7	5.7
Inflation	1.4	1.6	2.3	2.1	2.2	2.2	2.4	2.2
Before-tax profits	6.4	20.1	5.1	7.5	4.2	10.0	5.0	3.5
Current account (bil. $)	(64.9)	(60.1)	(56.9)	(45.0)	(37.0)	....	....	....

** or as noted*

Financial Forecast**

	Current 12-05-18	Q1 2019	Q2 2019	Q3 2019	Q4 2019	2018	2019	2020
Overnight rate	1.75	1.75	2.00	2.25	2.50	1.75	2.50	2.50
3 month T-Bills	1.67	1.96	2.18	2.38	2.46	1.68	2.46	2.29
Treasury yield curve								
2-Year	2.06	2.20	2.27	2.42	2.69	2.05	2.69	2.69
5-Year	2.08	2.22	2.35	2.48	2.81	2.08	2.81	2.89
10-Year	2.13	2.31	2.44	2.66	2.93	2.19	2.93	3.07
30-Year	2.26	2.40	2.52	2.73	3.00	2.28	3.00	3.13
CAD per USD	1.34	1.30	1.27	1.27	1.28	1.32	1.28	1.32
Oil price (WTI), U.S.$	53	65	68	71	68	62	68	62

*** end of period*

Quarterly pattern

	Q1 2018 actual	Q2 2018 actual	Q3 2018 actual	Q4 2018 forecast	Q1 2019 forecast	Q2 2019 forecast	Q3 2019 forecast	Q4 2019 forecast
Real GDP growth (q/q % chg. saar)	1.7	2.9	2.0	1.9	0.9	2.4	1.8	2.0
CPI (y/y % chg.)	2.1	2.3	2.7	2.2	1.7	2.0	2.0	2.4
CPI ex. food and energy (y/y % chg.)	1.8	1.8	2.1	2.0	1.6	2.0	1.9	2.2
Unemployment rate (%)	5.8	5.9	5.9	5.8	5.8	5.8	5.7	5.7

National Bank Financial

RBC ECONOMICS | RESEARCH

FINANCIAL MARKET FORECASTS

December 7, 2018

Interest rates (%, end of quarter,)

	Actual			Forecast									Actual	Forecast		
	18Q1	18Q2	18Q3	18Q4	19Q1	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	2017	2018	2019	2020
Canada																
Overnight	1.25	1.25	1.50	1.75	1.75	2.00	2.25	2.25	2.50	2.75	2.75	2.75	1.00	1.75	2.25	2.75
Three-month	1.10	1.26	1.59	1.65	1.65	1.95	2.15	2.20	2.45	2.70	2.70	2.75	1.06	1.65	2.20	2.75
Two-year	1.78	1.91	2.21	2.05	2.20	2.35	2.40	2.45	2.70	2.85	2.90	3.00	1.69	2.05	2.45	3.00
Five-year	1.97	2.07	2.34	2.15	2.35	2.55	2.70	2.75	2.95	3.10	3.10	3.15	1.87	2.15	2.75	3.15
10-year	2.09	2.17	2.43	2.20	2.45	2.75	2.90	2.90	3.05	3.20	3.30	3.30	2.04	2.20	2.90	3.30
30-year	2.23	2.20	2.42	2.35	2.60	2.85	2.95	2.95	3.10	3.25	3.30	3.30	2.27	2.35	2.95	3.30
Yield curve (10s-2s)	31	26	22	15	25	40	50	45	35	35	40	30	35	15	45	30
United States																
Fed funds*	1.75	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75	4.00	4.00	4.00	1.50	2.50	3.50	4.00
Three-month	1.73	1.93	2.19	2.35	2.65	2.90	3.15	3.35	3.60	3.85	3.85	3.85	1.39	2.35	3.35	3.85
Two-year	2.27	2.52	2.81	2.90	3.10	3.25	3.40	3.60	3.80	4.00	3.95	3.90	1.89	2.90	3.60	3.90
Five-year	2.56	2.73	2.94	3.10	3.25	3.40	3.55	3.65	3.85	4.05	4.00	3.95	2.20	3.10	3.65	3.95
10-year	2.74	2.85	3.05	3.30	3.45	3.60	3.70	3.75	3.90	4.05	4.05	4.00	2.40	3.30	3.75	4.00
30-year	2.97	2.98	3.19	3.50	3.65	3.75	3.80	3.85	3.95	4.05	4.05	4.00	2.74	3.50	3.85	4.00
Yield curve (10s-2s)	47	33	24	40	35	35	30	15	10	5	10	10	51	40	15	10
Yield spreads																
Three-month T-bills	-0.63	-0.67	-0.60	-0.70	-1.00	-0.95	-1.00	-1.15	-1.15	-1.15	-1.15	-1.10	-0.33	-0.70	-1.15	-1.10
Two-year	-0.49	-0.61	-0.60	-0.85	-0.90	-0.90	-1.00	-1.15	-1.10	-1.15	-1.05	-0.90	-0.20	-0.85	-1.15	-0.90
Five-year	-0.59	-0.66	-0.60	-0.95	-0.90	-0.85	-0.85	-0.90	-0.90	-0.95	-0.90	-0.80	-0.33	-0.95	-0.90	-0.80
10-year	-0.65	-0.68	-0.62	-1.10	-1.00	-0.85	-0.80	-0.85	-0.85	-0.85	-0.75	-0.70	-0.36	-1.10	-0.85	-0.70
30-year	-0.74	-0.78	-0.77	-1.15	-1.05	-0.90	-0.85	-0.90	-0.85	-0.80	-0.75	-0.70	-0.47	-1.15	-0.90	-0.70

Note: Interest Rates are end of period rates. * Top of 25 basis point range

Exchange rates (end of quarter,)

	Actual							Forecast					Actual		Forecast	
	17Q1	17Q2	17Q3	17Q4	18Q1	18Q2	18Q3	18Q4	19Q1	19Q2	19Q3	19Q4	2016	2017	2018	2019
AUD/USD	0.76	0.77	0.78	0.78	0.77	0.74	0.72	0.72	0.68	0.67	0.67	0.67	0.72	0.78	0.72	0.67
USD/CAD	1.33	1.30	1.25	1.26	1.29	1.31	1.29	1.33	1.35	1.34	1.33	1.33	1.34	1.26	1.33	1.33
EUR/USD	1.07	1.14	1.18	1.20	1.23	1.17	1.16	1.13	1.10	1.10	1.13	1.16	1.05	1.20	1.13	1.16
USD/JPY	111.4	112.4	112.5	112.7	106.3	110.8	113.7	114.0	117.0	119.0	122.0	125.0	117.0	112.7	114.0	125.0
USD/CNY	6.88	6.77	6.63	6.51	6.29	6.62	6.87	6.90	7.10	7.25	7.40	7.50	0.69	6.51	6.90	7.50
USD/CHF	1.00	0.96	0.97	0.97	0.95	0.99	0.98	1.00	1.04	1.05	1.04	1.03	1.02	0.97	1.00	1.03
GBP/USD	1.26	1.30	1.34	1.35	1.40	1.32	1.30	1.27	1.24	1.22	1.24	1.25	1.24	1.35	1.27	1.25

TD Bank - Dec 13 2018

.DESC	Q4-2018	Q1-2019	Q2-2019	Q3-2019	Q4-2019	Q1-2020	Q2-2020	Q3-2020	Q4-2020	Q1-2021	Q2-2021	Q3-2021	Q4-2021
Fed Funds Target Rate	2.50	2.50	2.75	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
US 3-mth T-Bill Rate Forecast	2.35	2.53	2.78	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.78
US 2-yr Gov't Bond Yield Forecast	2.80	2.85	2.90	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.90	2.80
US 5-yr Gov't Bond Yield Forecast	2.85	2.90	2.95	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	2.95	2.90
US 10-yr Gov't Bond Yield Forecas	3.00	3.05	3.10	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.10	3.05
overnight target	1.750	2.000	2.000	2.250	2.250	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500
CAN 3-mth T-Bill Rate Forecast	1.88	2.00	2.13	2.25	2.38	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
CAN 2-yr Gov't Bond Yield Foreca	2.05	2.20	2.35	2.45	2.50	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55
CAN 5-yr Gov't Bond Yield Foreca	2.10	2.30	2.45	2.55	2.65	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
CAN 10-yr Gov't Bond Yield Forec	2.20	2.40	2.55	2.70	2.80	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
Oil - West Texas Intermediate Cus	60.00	58.00	61.00	64.00	65.00	65.33	65.65	65.98	66.31	66.64	66.97	67.31	67.65
USD per CAD	0.758	0.763	0.769	0.775	0.781	0.787	0.789	0.791	0.792	0.794	0.795	0.796	0.797
USD per GBP	1.280	1.300	1.310	1.320	1.330	1.340	1.350	1.360	1.370	1.380	1.390	1.400	1.410
Unemployment Rate (%)	3.748	3.632	3.612	3.618	3.639	3.691	3.760	3.843	3.883	3.916	3.937	3.971	4.000

.DESC	Q1-2022	Q2-2022	Q3-2022	Q4-2022	Q1-2023	Q2-2023	Q3-2023	Q4-2023	Q1-2024	Q2-2024	Q3-2024	Q4-2024	Q1-2025	Q2-2025	Q3-2025	Q4-2025
Fed Funds Target Rate	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
US 3-mth T-Bill Rate Forecast	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65
US 2-yr Gov't Bond Yield Forecast	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
US 5-yr Gov't Bond Yield Forecast	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
US 10-yr Gov't Bond Yield Forecas	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
overnight target	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500	2.500
CAN 3-mth T-Bill Rate Forecast	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
CAN 2-yr Gov't Bond Yield Foreca	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55
CAN 5-yr Gov't Bond Yield Foreca	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
CAN 10-yr Gov't Bond Yield Forec	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85	2.85
Oil - West Texas Intermediate Cus	67.98	68.32	68.67	69.01	69.35	69.70	70.05	70.40	70.75	71.11	71.46	71.82	72.18	72.54	72.90	73.27
USD per CAD	0.798	0.799	0.800	0.800	0.801	0.802	0.802	0.802	0.803	0.803	0.804	0.804	0.804	0.804	0.805	0.805
USD per GBP	1.420	1.430	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440	1.440
Unemployment Rate (%)	4.029	4.060	4.108	4.121	4.139	4.159	4.177	4.182	4.186	4.206	4.198	4.190	4.181	4.188	4.177	4.166

Interest Rate Outlook	2018				2019				2020			
	Q1	Q2	Q3	Q4*	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Canada												
Overnight Target Rate	1.25	1.25	1.50	1.75	2.00	2.00	2.25	2.25	2.50	2.50	2.50	2.50
3-mth T-Bill Rate	1.10	1.26	1.59	1.66	2.00	2.13	2.25	2.38	2.50	2.50	2.50	2.50
2-yr Govt. Bond Yield	1.77	1.91	2.21	2.06	2.20	2.35	2.45	2.50	2.55	2.55	2.55	2.55
5-yr Govt. Bond Yield	1.96	2.06	2.33	2.07	2.30	2.45	2.55	2.65	2.70	2.70	2.70	2.70
10-yr Govt. Bond Yield	2.09	2.17	2.42	2.12	2.40	2.55	2.70	2.80	2.85	2.85	2.85	2.85
30-yr Govt. Bond Yield	2.23	2.20	2.41	2.27	2.55	2.75	2.95	3.05	3.10	3.10	3.10	3.10
10-yr-2-yr Govt Spread	0.32	0.26	0.21	0.06	0.20	0.20	0.25	0.30	0.30	0.30	0.30	0.30
U.S.												
Fed Funds Target Rate	1.75	2.00	2.25	2.50	2.50	2.75	3.00	3.00	3.00	3.00	3.00	3.00
3-mth T-Bill Rate	1.73	1.93	2.19	2.38	2.53	2.78	2.90	2.90	2.90	2.90	2.90	2.90
2-yr Govt. Bond Yield	2.27	2.52	2.81	2.77	2.85	2.90	2.95	2.95	2.95	2.95	2.95	2.95
5-yr Govt. Bond Yield	2.56	2.73	2.94	2.77	2.90	2.95	3.00	3.00	3.00	3.00	3.00	3.00
10-yr Govt. Bond Yield	2.74	2.85	3.05	2.91	3.05	3.10	3.15	3.15	3.15	3.15	3.15	3.15
30-yr Govt. Bond Yield	2.97	2.98	3.19	3.15	3.30	3.35	3.40	3.40	3.40	3.40	3.40	3.40
10-yr-2-yr Govt Spread	0.47	0.33	0.24	0.14	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Canada-U.S. Spreads												
Can - U.S. T-Bill Spread	-0.63	-0.67	-0.60	-0.72	-0.53	-0.65	-0.65	-0.52	-0.40	-0.40	-0.40	-0.40
Can - U.S. 10-Year Bond Spread	-0.65	-0.68	-0.63	-0.79	-0.65	-0.55	-0.45	-0.35	-0.30	-0.30	-0.30	-0.30

F: Forecast by TD Bank Group as at December 2018. All forecasts are end-of-period.
Source: Bloomberg, Bank of Canada, Federal Reserve, TD Economics. * Spot rate as at December 12, 2018 with the exception of policy rates.

Foreign Exchange Outlook		2018				2019				2020			
Currency	Exchange rate	Q1	Q2	Q3	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Exchange rate to U.S. dollar													
Japanese yen	JPY per USD	106	111	113	113	110	107	106	105	104	103	103	102
Euro	USD per EUR	1.23	1.17	1.16	1.14	1.16	1.18	1.20	1.21	1.22	1.23	1.24	1.25
U.K. pound	USD per GBP	1.40	1.32	1.31	1.26	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37
Exchange rate to Canadian dollar													
U.S. dollar	USD per CAD	0.78	0.76	0.77	0.75	0.76	0.77	0.78	0.78	0.79	0.79	0.79	0.79
Japanese yen	JPY per CAD	82.4	84.3	87.8	84.7	84.0	82.3	82.2	82.0	81.9	81.3	81.1	80.8
Euro	CAD per EUR	1.59	1.53	1.50	1.52	1.52	1.53	1.55	1.55	1.55	1.56	1.57	1.58
U.K. pound	CAD per GBP	1.81	1.73	1.69	1.69	1.70	1.70	1.70	1.70	1.70	1.71	1.72	1.73

F: Forecast by TD Bank Group as at December 2018. All forecasts are end-of-period.
Source: Bloomberg, Bank of Canada, Federal Reserve, TD Economics. * Spot rate as at December 12, 2018.

Commodity Price Outlook	2018				2019				2020			
	Q1	Q2	Q3	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Crude Oil (WTI, $US/bbl)	63	68	70	60	58	61	64	65	65	66	66	66
Natural Gas ($US/MMBtu)	3.10	2.82	2.90	3.85	3.70	3.60	3.50	3.40	3.30	3.32	3.33	3.35
Gold ($US/troy oz.)	1329	1306	1213	1225	1240	1275	1300	1325	1350	1355	1362	1367
Silver (US$/troy oz.)	16.74	16.56	15.02	14.60	15.25	16.00	16.50	17.00	17.50	17.75	17.70	17.70
Copper (cents/lb)	316	312	277	280	284	294	302	306	308	310	311	314
Nickel (US$/lb)	6.01	6.56	6.02	5.58	5.90	6.12	6.35	6.49	6.46	6.49	6.52	6.65
Aluminum (cents/lb)	98	102	93	91	97	98	99	101	101	102	102	103
Wheat ($US/bu)	7.42	7.46	6.70	6.92	6.94	6.94	7.02	7.05	7.00	6.95	6.95	6.90

F: Forecast by TD Bank Group as at December 2018. All forecasts are period averages.
Source: Bloomberg, TD Economics, USDA (Haver).

IHS Markit - Dec 10 2018

Table 1																												
Selected Economic Indicators																												
	18Q4	19Q1	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4	22Q1	22Q2	22Q3	22Q4	23Q1	23Q2	23Q3	23Q4	24Q1	24Q2	24Q3	24Q4	25Q1	25Q2	25Q3
Financial Markets																												
3-Month T-Bill Rate (%)	1.73	1.83	2.01	2.26	2.51	2.76	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01
US 3-Month T-Bill Rate (%)	2.36	2.59	2.72	2.86	2.86	3.01	3.02	3.20	3.18	3.17	3.17	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.13	2.92	2.92	2.92	2.89	2.69	2.69	2.69	2.69	2.69
Canada-US Differential (% pts.)	-0.63	-0.76	-0.72	-0.60	-0.35	-0.25	-0.01	-0.19	-0.17	-0.16	-0.16	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.15	-0.12	0.09	0.09	0.09	0.12	0.32	0.32	0.32	0.32	0.32
Prime Rate (%)	3.95	4.03	4.20	4.45	4.70	4.95	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20	5.20
Overnight Rate (%)	1.75	1.83	2.00	2.25	2.50	2.75	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
GOC Bond Rate (1-3 yrs.) (%)	2.23	2.42	2.57	2.72	2.85	2.97	3.08	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.09	3.09	3.08	3.08	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.06
GOC Bond Rate (3-5 yrs.) (%)	2.36	2.57	2.71	2.84	2.93	3.02	3.10	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.11	3.11	3.10	3.10	3.09	3.09	3.09	3.08	3.08	3.09	3.09	3.08	3.07
GOC Ten-Year Bond Rate (%)	2.44	2.74	2.88	2.97	3.03	3.08	3.12	3.14	3.15	3.15	3.15	3.15	3.15	3.14	3.14	3.14	3.13	3.12	3.11	3.11	3.11	3.10	3.10	3.10	3.10	3.10	3.10	3.09
US Ten-Year T-Note Rate (%)	3.11	3.14	3.28	3.38	3.43	3.49	3.53	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.55	3.54	3.54	3.53	3.52	3.51	3.51	3.51	3.51	3.50	3.51	3.51	3.50	3.49
Exchange Rate (US-Can.)	76.0	76.2	76.2	77.2	78.5	78.7	78.6	78.9	79.3	79.4	79.7	79.9	79.8	79.9	79.9	80.0	80.0	80.0	80.0	80.0	80.1	80.2	80.3	80.4	80.5	80.6	80.7	80.8

IHS Markit - Dec 10 2018

Table 24 Interest Rates (Percent)	18Q4	19Q1	19Q2	19Q3	19Q4	20Q1	20Q2	20Q3	20Q4	21Q1	21Q2	21Q3	21Q4	22Q1	22Q2	22Q3	22Q4	23Q1	23Q2	23Q3	23Q4	24Q1	24Q2	24Q3	24Q4	25Q1	25Q2	25Q3	25Q4
Overnight Money	1.75	1.83	2.00	2.25	2.50	2.75	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Bank Rate	2.00	2.08	2.25	2.50	2.75	3.00	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Government of Canada																													
Treasury Bills																													
3 Months	1.73	1.83	2.01	2.26	2.51	2.76	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01
6 Months	1.91	2.00	2.18	2.44	2.69	2.94	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19	3.19
Bonds																													
1-3 Years	2.23	2.42	2.57	2.72	2.85	2.97	3.08	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.09	3.09	3.08	3.08	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.07	3.06	3.05
3-5 Years	2.36	2.57	2.71	2.84	2.93	3.02	3.10	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.11	3.11	3.10	3.10	3.09	3.09	3.09	3.08	3.08	3.09	3.09	3.08	3.07	3.06
5 Years	2.39	2.61	2.75	2.87	2.96	3.04	3.11	3.12	3.13	3.13	3.13	3.13	3.13	3.13	3.12	3.12	3.11	3.11	3.10	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.08	3.08	3.07
5-10 Years	2.46	2.69	2.83	2.93	3.00	3.07	3.12	3.14	3.14	3.14	3.14	3.14	3.14	3.14	3.13	3.13	3.12	3.12	3.11	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.09	3.08	3.07
10 Years	2.44	2.74	2.88	2.97	3.03	3.08	3.12	3.14	3.15	3.15	3.15	3.15	3.15	3.14	3.14	3.14	3.13	3.12	3.11	3.11	3.11	3.10	3.10	3.10	3.10	3.10	3.10	3.09	3.08
10+ Years	2.47	2.78	2.93	3.04	3.10	3.16	3.20	3.22	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.22	3.22	3.21	3.20	3.20	3.19	3.19	3.19	3.19	3.19	3.19	3.18	3.17	3.16
30 Years	2.47	2.79	2.94	3.05	3.11	3.17	3.22	3.24	3.24	3.24	3.24	3.25	3.25	3.24	3.24	3.24	3.23	3.22	3.21	3.21	3.20	3.20	3.20	3.20	3.20	3.20	3.19	3.18	3.17

Conference Board - Dec 14 2018

Description:	Canada - 3 Month Treasury Bill ()	Exchange Rate (U.S./Canada)	United States - 3 Month Treasury Bill ()	Canada, Federal Bonds: Long-Term ()	Canada, Federal Bonds: 10 Years ()
Mnemonic:	RTB90	PFX	USRTB90	RGOCL	RGOC10
2018.01	1.151	1.26483333	1.58333337	2.32666667	2.21
2018.02	1.249	1.29116667	1.87666667	2.30333333	2.22666667
2018.03	1.499	1.30693333	2.07666659	2.34666667	2.34
2018.04	1.72	1.318795	2.33	2.45	2.38
2019.01	1.876609	1.343031	2.58809	2.841988	2.748655
2019.02	1.959942	1.335061	2.787257	3.222544	3.07921
2019.03	2.064109	1.312693	2.861424	3.599627	3.406294
2019.04	2.230775	1.290154	2.861424	3.771849	3.578516
2020.01	2.376609	1.28065	2.861424	3.891294	3.69796
2020.02	2.564109	1.275507	2.861424	4.010044	3.81671
2020.03	2.793275	1.271102	2.861424	4.023238	3.829905
2020.04	2.939109	1.267683	2.86059	4.028794	3.83546
2021.01	2.959942	1.265008	2.859757	4.029488	3.836155
2021.02	2.959942	1.261874	2.859757	4.029488	3.836155
2021.03	2.959942	1.260011	2.859757	4.029488	3.836155
2021.04	2.959942	1.258174	2.859757	4.029488	3.836155
2022.01	2.959942	1.255122	2.859757	4.029488	3.836155
2022.02	2.959942	1.252095	2.859757	4.029488	3.836155
2022.03	2.959942	1.249097	2.859757	4.029488	3.836155
2022.04	2.959942	1.246125	2.859757	4.029488	3.836155
2023.01	2.959942	1.243625	2.859757	4.029488	3.836155
2023.02	2.959942	1.241068	2.859757	4.029488	3.836155
2023.03	2.959942	1.237778	2.859757	4.029488	3.836155
2023.04	2.959942	1.234518	2.859757	4.029488	3.836155

REFERENCE:

Application pg. 8; MH-93, MFR 55 (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

In its Application, Manitoba Hydro states:

The higher net finance expense reflects earlier than planned borrowings to take advantage of favourable market conditions, lower capitalized interest due to delayed capital spending as well as higher foreign exchange losses on U.S. cash balances resulting from the strengthening Canadian dollar. This was partially offset by higher interest income on pre-funded cash balances.

QUESTION:

Provide the detail of the total finance expense (in similar detail as PUB MFR 55) for the years 2017/18 actual and forecast for 2018/19 and 2019/20 and a comparison with the detail of the finance expense for each of the years included in MH93 and explain the changes.

RESPONSE:

Please see the following schedule.

MANITOBA HYDRO
Summary of Total Finance Expense
($ thousands CAD)

	Actual 2018	Outlook 2019	Interim Budget 2020	MH93 Forecast 2018	MH93 Forecast 2019	MH93 Forecast 2020	Difference 2018	Difference 2019	Difference 2020
Interest on Short & Long Term Debt									
Gross Interest	774	817	890	765	788	842	9	29	48
Provincial Guarantee Fee	154	183	212	154	186	212	(0)	(3)	(1)
Amortization of (Premiums), Discounts, and Transaction Costs	2	2	2	1	1	1	0	1	1
Intercompany Interest Receivable	(15)	(15)	(17)	(15)	(15)	(16)	(0)	0	(1)
Total Interest on Short & Long Term Debt	**914**	**987**	**1,087**	**906**	**961**	**1,039**	**9**	**27**	**48**
Interest Allocated to Construction	**(343)**	**(285)**	**(315)**	**(360)**	**(320)**	**(319)**	**17**	**35**	**4**
Interest Earned on Sinking Fund	(0)	(2)	(9)	(1)	(6)	(14)	1	4	5
Realized Foreign Exchange (Gains)/ Losses on Debt in Cash Flow Hedges	17	20	22	27	28	28	(10)	(8)	(6)
Revaluation of Dual Currency Bonds	1	1	1	1	1	1	0	0	(0)
Corporate Allocation	(18)	(18)	(18)	(18)	(18)	(18)	0	-	-
Other Amortization	30	31	30	32	32	31	(2)	(1)	(1)
Total Finance Expense	**602**	**733**	**799**	**587**	**677**	**749**	**15**	**56**	**50**

Fiscal 2018: Finance expense in 2017/18 is $15 million higher than forecast in MH93 mainly due to less capitalized interest predominantly related to lower Bipole III capital expenditures.

Fiscal 2019: Finance expense in the 2018/19 Outlook is $56 million higher than forecast in MH93 due to lower capitalized interest which was mainly a result of an early in service date for Bipole III and a lower rate on capitalized interest. Gross interest is higher in the 2018/19 Outlook as Manitoba Hydro reverted to the practice of targeting a 20 year weighted average term to maturity for new borrowings as opposed to the 12 year assumption in MH93 as well as slightly higher consensus forecast rates .

Fiscal 2020: Finance expense in the 2019/20 Interim Budget is $50 million higher than forecast in MH93 mainly due to higher gross interest as Manitoba Hydro reverted to the practice of targeting a 20 year weighted average term to maturity for new borrowings as opposed to the 12 year assumption in MH93 as well as slightly higher consensus forecast rates in the 2019/20 Interim Budget.

REFERENCE:

Application pg. 8; MH-93, MFR 55 (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

In its Application, Manitoba Hydro states:
The higher net finance expense reflects earlier than planned borrowings to take advantage of favourable market conditions, lower capitalized interest due to delayed capital spending as well as higher foreign exchange losses on U.S. cash balances resulting from the strengthening Canadian dollar. This was partially offset by higher interest income on pre-funded cash balances.

QUESTION:

Provide the detail of the total finance expense (in similar detail as PUB MFR 55) for the years 2017/18 actual and forecast for 2018/19 and 2019/20 and a comparison with the detail of the finance expense for each of the years included in MH93 and explain the changes.

RESPONSE:

Please see the following schedule.

MANITOBA HYDRO
Summary of Total Finance Expense
($ thousands CAD)

	Actual 2018	Current Outlook 2019	Approved Budget 2020	MH93 Forecast 2018	MH93 Forecast 2019	MH93 Forecast 2020	Difference 2018	Difference 2019	Difference 2020
Interest on Short & Long Term Debt									
Gross Interest	774	803	856	765	788	842	9	15	15
Provincial Guarantee Fee	154	182	203	154	186	212	(0)	(5)	(10)
Amortization of (Premiums), Discounts, and Transaction Costs	2	4	4	1	1	1	0	3	3
Intercompany Interest Receivable	(15)	(15)	(16)	(15)	(15)	(16)	(0)	0	(0)
Total Interest on Short & Long Term Debt	**914**	**974**	**1,047**	**906**	**961**	**1,039**	**9**	**13**	**8**
Interest Allocated to Construction	**(343)**	**(275)**	**(311)**	**(360)**	**(320)**	**(319)**	**17**	**45**	**8**
Interest Earned on Sinking Fund	(0)	-	-	(1)	(6)	(14)	1	6	14
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	17	29	30	27	28	28	(10)	1	2
Revaluation of Dual Currency Bonds	1	1	1	1	1	1	0	0	(0)
Corporate Allocation	(18)	(18)	(18)	(18)	(18)	(18)	0	-	-
Other Amortization	30	32	30	32	32	31	(2)	0	(1)
Total Finance Expense	**602**	**743**	**779**	**587**	**677**	**749**	**15**	**66**	**30**

Fiscal 2018: Finance expense in 2017/18 is $15 million higher than forecast in MH Exhibit 93 mainly due to less capitalized interest predominantly related to lower Bipole III capital expenditures.

Fiscal 2019: Finance expense in the Current Outlook is $66 million higher than forecast in MH Exhibit 93 due to lower capitalized interest which was mainly a result of an early in service date for Bipole III, lower capital expenditures and a lower rate on capitalized interest. Gross interest is higher in the Current Outlook due to higher consensus forecast rates and as a result of targeting a 20 year weighted average term to maturity for new borrowings as opposed to the 12 year assumption in MH Exhibit 93. This is partially offset by less gross interest and Provincial Guarantee Fee resulting from a lower volume of debt outstanding in the Current Outlook than in MH Exhibit 93 mainly due to lower capital expenditures.

Fiscal 2020: Finance expense in the Approved Budget is $30 million higher than forecast in MH Exhibit 93. The Approved Budget reflects Manitoba Hydro's current practice of minimizing sinking fund balances to reduce finance expense associated with higher gross debt levels which was not modeled in MH Exhibit 93. Higher gross debt levels lead to higher levels of the sinking fund management fee (charged at 0.075% of the sinking fund balance at the previous year end), higher carrying costs on the sinking fund balances (as sinking fund investments typically earn a lower return than is paid on the debt to finance the sinking fund contributions) and higher amounts paid for the Provincial Guarantee Fee (which is based on gross debt levels and not the level of net debt which deducts sinking fund balances). As a result of this current practice, there is no interest earned on the sinking fund in the Approved Budget. In addition, capitalized interest is lower than forecast in MH Exhibit 93 predominantly due to a lower rate on capitalized interest. Gross interest is higher as Manitoba Hydro reverted to the practice of targeting a 20 year weighted average term to maturity for new borrowings as opposed to the 12 year WATM assumed in MH Exhibit 93. This is partially offset by less gross interest and Provincial Guarantee Fee resulting from a lower volume of debt outstanding in the Current Outlook than in MH Exhibit 93 mainly due the cumulative impact of lower capital expenditures.

REFERENCE:

2017/18 GRA PUB/MH II-28, PUB MFR 56

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide an update to the continuity schedule for debt through the test year to 2023/24 in a similar format as PUB MFR 56 based on the current debt management plan.

RESPONSE:

The continuity schedule for debt updated through to the test year is provided below.

The information requested for the period beyond the 2019/20 test year is not available at the current time. The assumptions underpinning the requested information will be considered in the context of the MHEB's approval of the Corporation's next Integrated Financial Forecast and provided in Manitoba Hydro's next full GRA.

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

(in $ millions Canadian Dollars)

Long Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Outlook 2019**	**Interim Budget 2020**
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,200	22,129
Long Term Debt Proceeds	1,013	300	180	173	981	423	1,425	915	698	807	1,320	2,210	2,165	2,186	3,400	3,950	2,400
Long Term Debt Matured	(473)	(241)	(111)	(80)	(311)	(366)	(452)	(723)	(25)	(242)	(613)	(654)	(362)	(320)	(582)	(1,000)	(366)
Carrying Value Adjustments*	(418)	(245)	(104)	(35)	(327)	559	(622)	(83)	62	38	176	256	44	45	(56)	(21)	(8)
Closing Balance	**7,390**	**7,204**	**7,169**	**7,227**	**7,571**	**8,187**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,200**	**22,129**	**24,155**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Outlook 2019**	**Interim Budget 2020**
Opening Balance	128	93	59	-	148	-	100	-	-	-	-	-	-	-	-	50	-
Increase (Decrease)	(35)	(34)	(59)	148	(148)	100	(100)	-	-	-	-	-	-	-	50	(50)	-
Closing Balance	**93**	**59**	**-**	**148**	**-**	**100**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**50**	**-**	**-**

Total Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Outlook 2019**	**Interim Budget 2020**
Long Term Debt	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,200	22,129	24,155
Short Term Debt	93	59		148	-	100	-	-	-	-	-	-	-	-	50	-	-
Total Debt	**7,483**	**7,263**	**7,169**	**7,375**	**7,571**	**8,287**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,250**	**22,129**	**24,155**
Proportion of Short Term Debt to Total Debt	1%	1%	0%	2%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Consolidated Debt Ratio	87%	85%	81%	80%	73%	77%	73%	73%	74%	75%	76%	82%	83%	84%	85%	86%	87%

REFERENCE:

2017/18 GRA PUB/MH II-28, PUB MFR 56

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide an update to the continuity schedule for debt through the test year to 2023/24 in a similar format as PUB MFR 56 based on the current debt management plan.

RESPONSE:

The continuity schedule for debt updated through to the test year is provided below.

The information requested for the period beyond the 2019/20 test year is not available at the current time. The assumptions underpinning the requested information will be considered in the context of the MHEB's approval of the Corporation's next Integrated Financial Forecast and provided in Manitoba Hydro's next full GRA.

Finance Expense - Debt Levels PUB-MH I-36U - IFF19

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

(in $ millions Canadian Dollars)

Long Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Current Outlook 2019**	**Approved Budget 2020**
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,200	21,323
Long Term Debt Proceeds	1,013	300	180	173	981	423	1,425	915	698	807	1,320	2,210	2,165	2,186	3,400	3,365	2,200
Long Term Debt Matured	(473)	(241)	(111)	(80)	(311)	(366)	(452)	(723)	(25)	(242)	(613)	(654)	(362)	(320)	(582)	(1,232)	(247)
Carrying Value Adjustments*	(418)	(245)	(104)	(35)	(327)	559	(622)	(83)	62	38	176	256	44	45	(56)	(10)	(8)
Closing Balance	**7,390**	**7,204**	**7,169**	**7,227**	**7,571**	**8,187**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,200**	**21,323**	**23,268**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Current Outlook 2019**	**Approved Budget 2020**
Opening Balance	128	93	59	-	148	-	100	-	-	-	-	-	-	-	-	50	-
Increase (Decrease)	(35)	(34)	(59)	148	(148)	100	(100)	-	-	-	-	-	-	-	50	(50)	-
Closing Balance	**93**	**59**	**-**	**148**	**-**	**100**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**50**	**-**	**-**

Total Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Current Outlook 2019**	**Approved Budget 2020**
Long Term Debt	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,200	21,323	23,268
Short Term Debt	93	59		148	-	100	-	-	-	-	-	-	-	-	50	-	-
Total Debt	**7,483**	**7,263**	**7,169**	**7,375**	**7,571**	**8,287**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,250**	**21,323**	**23,268**
Proportion of Short Term Debt to Total Debt	1%	1%	0%	2%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Consolidated Debt Ratio	87%	85%	81%	80%	73%	77%	73%	73%	74%	75%	76%	82%	83%	84%	85%	86%	86%

REFERENCE:

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Describe and illustrate with detailed calculations how the interest capitalized rates were determined for the years 2017/18, 2018/19 and 2019/20 in this application and compare and explain differences with that used in MH93.
b) Provide the detail summary of change in the interest allocated to construction for 2017/18, 2018/19 and 2019/20 with that forecast in each of the years in MH93.

RESPONSE:

a) The methodology for calculating capitalized interest rates has not changed in the current Application. The capitalized interest rates were calculated by dividing the forecast total interest expense by the forecast average debt. The capitalized interest rates used in this Application were based on interest expense and debt levels in IFF16. The capitalized interest rates used in MH93 were based on interest expense and debt levels in IFF15. Following are tables with detailed calculations of the capitalized interest rates used in this Application and MH93 as well as a table which provides the differences between the two.

CALCULATION OF PROJECTED INTEREST CAPITALIZATION RATE IN APPLICATION

For year ending March 31:	2018	2019	2020 (millions)
Interest on Debt	757	780	825
Provincial Guarantee Fee	158	190	215
Amortization of Premiums and Discounts	1	1	1
Interest on Winnipeg Hydro Obligation	16	16	16
Total Interest Expense	932	987	1,057
Long Term Debt & Winnipeg Hydro Obligation	18,308	21,456	22,041
Current Portion of Long Term Debt	1,002	348	1,293
Short Term Debt		-	-
Total Debt & Obligations	19,310	21,803	23,334
Average Debt & Obligations	17,801	20,557	22,569
Average Semi-Annual Rate	5.23%	4.80%	4.68%
Effective Annual Rate	5.30%	4.86%	4.74%

CALCULATION OF PROJECTED INTEREST CAPITALIZATION RATE IN MH93

For year ending March 31:	2018	2019	2020 (millions)
Interest on Debt	813	858	908
Provincial Guarantee Fee	174	202	217
Amortization of Premiums and Discounts	2	2	2
Interest on Winnipeg Hydro Obligation	16	16	16
Total Interest Expense	1,005	1,078	1,143
Long Term Debt & Winnipeg Hydro Obligation	19,461	21,607	22,248
Current Portion of Long Term Debt	992	335	880
Short Term Debt	-	-	-
Total Debt & Obligations	20,453	21,941	23,128
Average Debt & Obligations	19,188	21,197	22,535
Average Semi-Annual Rate	5.24%	5.09%	5.07%
Effective Annual Rate	5.31%	5.15%	5.14%

DIFFERENCES APPLICATION vs MH93

For year ending March 31:	2018	2019	2020 (millions)
Interest on Debt	(56)	(79)	(83)
Provincial Guarantee Fee	(17)	(12)	(2)
Amortization of Premiums and Discounts	(1)	(1)	(1)
Interest on Winnipeg Hydro Obligation	-	-	-
Total Interest Expense	(73)	(91)	(86)
Long Term Debt & Winnipeg Hydro Obligation	(1,153)	(151)	(207)
Current Portion of Long Term Debt	10	13	413
Short Term Debt	-	-	-
Total Debt & Obligations	(1,143)	(138)	206
Average Debt & Obligations	(1,386)	(640)	34
Average Semi-Annual Rate	0.0%	-0.3%	-0.4%
Effective Annual Rate	0.0%	-0.3%	-0.4%

b) **Fiscal 2018:** Capitalized interest in the Application is $17 million lower than forecast in MH93 mainly due to lower capital expenditures related to Bipole III.

Fiscal 2019: Capitalized interest in the Application is $35 million lower than forecast in MH93 predominantly due to an early in service date for Bipole III and a lower rate on capitalized interest.

Fiscal 2020: Capitalized interest in the Application is $4 million lower than forecast in MH93 predominantly due to a lower rate on capitalized interest.

REFERENCE:

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Describe and illustrate with detailed calculations how the interest capitalized rates were determined for the years 2017/18, 2018/19 and 2019/20 in this application and compare and explain differences with that used in MH93.

b) Provide the detail summary of change in the interest allocated to construction for 2017/18, 2018/19 and 2019/20 with that forecast in each of the years in MH93.

RESPONSE:

a) The methodology for calculating capitalized interest rates has not changed in the Current Outlook and Approved Budget compared to MH Exhibit 93. The capitalized interest rates were calculated by dividing the forecast total interest expense by the forecast average debt. The capitalized interest rates used in the Current Outlook and Approved Budget were based on interest expense and debt levels in the Application. The capitalized interest rates used in MH Exhibit 93 were based on interest expense and debt levels in IFF15. The following tables contain detailed calculations of the capitalized interest rates used in the Current Outlook and Approved Budget and MH Exhibit 93 as well as a table which provides the differences between the two.

CURRENT OUTLOOK and APPROVED BUDGET
CALCULATION OF PROJECTED INTEREST CAPITALIZATION RATE

For year ending March 31: (millions)

	2018	2019	2020
Interest on Debt	757	801	866
Provincial Guarantee Fee	158	187	215
Amortization of Premiums and Discounts	1	2	2
Interest on Winnipeg Hydro Obligation	16	16	16
Total Interest Expense	932	1,007	1,099
Long Term Debt & Winnipeg Hydro Obligation	18,308	21,583	22,399
Current Portion of Long Term Debt	1,002	345	1,288
Short Term Debt		-	-
Total Debt & Obligations	19,310	21,928	23,687
Average Debt & Obligations	17,801	20,567	22,808
Average Semi-Annual Rate	5.23%	4.90%	4.82%
Effective Annual Rate	5.30%	4.96%	4.88%

CALCULATION OF PROJECTED INTEREST CAPITALIZATION RATE IN MH93

For year ending March 31: (millions)

	2018	2019	2020
Interest on Debt	813	858	908
Provincial Guarantee Fee	174	202	217
Amortization of Premiums and Discounts	2	2	2
Interest on Winnipeg Hydro Obligation	16	16	16
Total Interest Expense	1,005	1,078	1,143
Long Term Debt & Winnipeg Hydro Obligation	19,461	21,607	22,248
Current Portion of Long Term Debt	992	335	880
Short Term Debt	-	-	-
Total Debt & Obligations	20,453	21,941	23,128
Average Debt & Obligations	19,188	21,197	22,535
Average Semi-Annual Rate	5.24%	5.09%	5.07%
Effective Annual Rate	5.31%	5.15%	5.14%

DIFFERENCES CURRENT OUTLOOK AND APPROVED BUDGET vs MH93

For year ending March 31: (millions)	2018	2019	2020
Interest on Debt	(56)	(57)	(42)
Provincial Guarantee Fee	(17)	(14)	(2)
Amortization of Premiums and Discounts	(1)	0	0
Interest on Winnipeg Hydro Obligation	-	-	-
Total Interest Expense	(73)	(71)	(44)
Long Term Debt & Winnipeg Hydro Obligation	(1,153)	(24)	151
Current Portion of Long Term Debt	10	11	408
Short Term Debt	-	-	-
Total Debt & Obligations	(1,143)	(13)	559
Average Debt & Obligations	(1,386)	(630)	273
Average Semi-Annual Rate	0.0%	-0.2%	-0.3%
Effective Annual Rate	0.0%	-0.2%	-0.3%

b) **Fiscal 2018:** Capitalized interest in 2018 is $17 million lower than forecast in MH Exhibit 93 mainly due to lower capital expenditures related to Bipole III.

Fiscal 2019: Capitalized interest in the Current Outlook is $45 million lower than forecast in MH Exhibit 93 predominantly due to an early in service date for Bipole III, as well as lower capital expenditures for Bipole III and a lower rate on capitalized interest.

Fiscal 2020: Capitalized interest in the Approved Budget is $8 million lower than forecast in MH Exhibit 93 predominantly due to a lower rate on capitalized interest.

REFERENCE:

Application pg.8; 2017/18 GRA PUB/MH I-32a-b, PUB MFR 57, 58, and 59

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide the term sheets of amended long term debt issuance since the last GRA for the years 2017/18 and 2018/19.

b) Provide a listing of debt issued in same format of PUB MFR 58 from the 2017/18 & 2018/19 GRA and highlight any new issuances since the last GRA.

c) Provide an update and complete the following table detailing the debt issuance and corresponding interest rates.

Year	Debt Issued in year	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate IFF 16 Updated (MH93)	Notional Interest
2016	2,208.2	3.87%	5.68%		$85.5
2017	2,162.8	3.48%	5.41%		$75.3
2018					
2019					
2020					
2021					
2022					
2023					
Total					

d) Provide a comparison of the actual and forecast amounts for the years 2018 through 2023 from the table in (e) with PUB/MH 1-32 b (2017/18 & 2018/19 GRA) and explain the differences.

e) Provide in a similar format to MFR 59 a schedule detailing the current refinancing plans, the weighted average term of outstanding debt, the principle amount and proportions of debt maturing in 10 years, 20 years and greater than 20 years as projected at the end of 2019/20.

RESPONSE:

a) The terms for Manitoba Hydro's new and amended long term debt financings are provided for fiscal years 2017/18 and 2018/19 to December 31, 2018 below.

2017/18 The actual long term financings for the year are CAD $3,380.6 million made up of:

- $2,982.9 million for new borrowing requirements.
- $147.7 million to refinance maturing long term debt.
- $250.0 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year, per quarter, are as follows:

Quarter 1 On April 3, 2017, Manitoba Hydro secured long term debt series C137-13 for CAD $50 million and a March 5, 2063 maturity date. C137-13 was issued at a premium with proceeds of $51.2 million (net of commissions), a fixed rate coupon of 3.45%, and an all-in yield of 3.342%. The debt was issued to finance new borrowing requirements.

On May 4, 2017, Manitoba Hydro secured long term debt series GT for USD $500 million and a May 4, 2022 maturity date. The issue was swapped to CAD $683.4 million and a fixed rate coupon of 1.630%. The debt was issued to finance new borrowing requirements.

On May 5, 2017, Manitoba Hydro secured long term debt series GO-3 for CAD $300 million and a September 5, 2021 maturity date. GO-3 was issued at a discount with proceeds of $299.9 million (net of commissions), a fixed rate

coupon of 1.55%, and an all-in yield of 1.561%. The debt was issued to finance new borrowing requirements.

Quarter 2 On July 11, 2017, Manitoba Hydro secured long term debt series C137-16 for CAD $150 million and a March 5, 2063 maturity date. C137-16 was issued at a premium with proceeds of $160.4 million (net of commissions), a fixed rate coupon of 3.45%, and an all-in yield of 3.163%. The debt was issued to finance new borrowing requirements.

On July 28, 2017, Manitoba Hydro secured long term debt series GR-3 for CAD $300 million and a September 5, 2048 maturity date. GR-3 was issued at a premium with proceeds of $305.2 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.310%. The debt was issued to refinance $2.2 million of HydroBonds Series 12 five year floating rate debt early redemptions. The remaining $297.8 million of the debt was issued to finance new borrowing requirements.

On August 21, 2017, Manitoba Hydro secured long term debt series GS-2 for CAD $300 million and a June 2, 2027 maturity date. GS-2 was issued at a discount with proceeds of $296.4 million (net of commissions), a fixed rate coupon of 2.60%, and an all-in yield of 2.741%. The debt was issued to finance new borrowing requirements.

On September 7, 2017, Manitoba Hydro secured long term debt series C157-3 for AUD $75 million and an August 17, 2027 maturity date. The issue was swapped to CAD $74.3 million and a fixed rate coupon of 2.684%. The debt was issued to finance new borrowing requirements.

Quarter 3 On October 2, 2017, Manitoba Hydro secured long term debt series GR-4 for CAD $300 million and a September 5, 2048 maturity date. GR-4 was issued at a discount with proceeds of $294.6 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.495%. The debt was issued to refinance $250 million of maturing debt series FJ. A forward fixed interest rate swap that was previously linked to debt issue FJ was re-linked to existing series GO-2 underlying refinancing, which amended the fixed rate on $250 million of the debt stream to 4.582%. The remaining $50 million of the debt was issued to finance new borrowing requirements.

On October 5, 2017, Manitoba Hydro secured long term debt series C157-4 for AUD $50 million and an August 17, 2027 maturity date. The issue was swapped to CAD $49.1 million and a fixed rate coupon of 2.900%. The debt was issued to finance new borrowing requirements.

On November 23, 2017, Manitoba Hydro secured long term debt series GR-5 for CAD $300 million and a September 5, 2048 maturity date. GR-5 was issued at a premium with proceeds of $312.3 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.190%. The debt was issued to refinance $55.5 million of maturing debt series C-011. The remaining $244.5 million of the debt was issued to finance new borrowing requirements.

Quarter 4 On January 1, 2018, Manitoba Hydro secured long term debt series GS-3 for CAD $300 million and a June 2, 2027 maturity date. GS-3 was issued at a discount with proceeds of $298.8 million (net of commissions), a fixed rate coupon of 2.60% and an all-in yield of 2.893%. The debt was issued to refinance $90 million (of total $255.0 million) of maturing debt series BM. The remaining $210 million of the debt was issued to finance new borrowing requirements.

On February 2, 2018, Manitoba Hydro secured long term debt series GR-6 for CAD $300 million and a September 5, 2048 maturity date. GR-6 was issued at premium with proceeds of $312.5 million (net of commissions), a fixed rate coupon of 3.40% and an all-in yield of 3.186%. The debt was issued to finance new borrowing requirements.

On February 15, 2018, Manitoba Hydro secured long term debt series GS-4 for CAD $150 million and a June 2, 2027 maturity date. GS-4 was issued at a discount with proceeds of $144.6 million (net of commissions), a fixed rate coupon of 2.60% and an all-in yield of 3.049%. The debt was issued to finance new borrowing requirements.

On February 20, 2018, Manitoba Hydro secured long term debt series C157-5 for AUD $75 million and an August 17, 2027 maturity date. The issue was swapped to CAD $63.9 million (C157-5A) and a fixed rate coupon of 3.058% as well as CAD $9.9 million (C157-5B) and a floating rate coupon of 3M BA + 0.2958%. The debt was issued to finance new borrowing requirements.

On March 9, 2018, Manitoba Hydro secured long term debt series C161-2 for AUD $50 million and an August 22, 2028 maturity date. The issue was swapped to CAD $50 million and a fixed rate coupon of 2.903%. The debt was issued to finance new borrowing requirements.

2018/19 The actual long term financings for the year to date are CAD $2,950.0 million made up of:

- $1,613.0 million for new borrowing requirements.
- $951.5 million to refinance maturing long term debt.
- $385.5 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year to December 31, 2018, per quarter, are as follows:

Quarter 1 On April 9, 2018, Manitoba Hydro secured long term debt series GS-5 for CAD $300 million and a June 2, 2027 maturity date. GS-5 was issued at a discount with proceeds of $289.9 million (net of commissions), a fixed rate coupon of 2.60%, and an all-in yield of 3.026%. The debt was issued to refinance $85 million of Series C132-2A, $19 million of Series C132-2B and $185.9 million (of total $200 million) of Series C132. The remaining $10.1 million of the debt was issued to finance new borrowing requirements. Forward fixed interest rate swaps that were previously linked to debt series C132-2A ($85 million) and C132-2B ($19 million) were re-linked to existing series GS which amended the fixed rates on $85 million of the debt stream to 4.826%. on $19 million of the debt stream to 4.756%.

On April 17, 2018, Manitoba Hydro secured long term debt series GU for CAD $200 million and a June 2, 2028 maturity date. GU was issued at a discount with proceeds of $198.2 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.103%. The debt was issued to finance new borrowing requirements.

On May 4, 2018, Manitoba Hydro secured long term debt series GU-2 for CAD $350 million and a June 2, 2028 maturity date. GU-2 was issued at a discount with proceeds of $344.1 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.195%. The debt was issued to refinance $14.1 million (of total $200 million) of Series C132. The remaining $335.9 million was issued to finance new borrowing requirements.

On May 22, 2018, Manitoba Hydro secured long term debt series GR-7 for CAD $300 million and a September 5, 2048 maturity date. GR-7 was issued at a discount with proceeds of $299.4 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.411%. The debt was issued to finance new borrowing requirements.

On June 1, 2018, Manitoba Hydro secured floating rate long term debt series C162 with a coupon rate of 3 Month BA – 0.195% for CAD $200 million and a March 15, 2020 maturity date. CAD $192.75 million was swapped to USD $150 million floating rate debt to refinance debt series GE-1. A forward fixed interest rate swap that was previously linked to debt series GE-1 was re-linked to the C162 underlying refinancing which amended the fixed rate debt stream to 5.796% on USD $150,000,000 (C162-D). The residual $7.25 million remained in CAD floating at 3BA – 0.195% (C162-E).

On June 1, 2018, Manitoba Hydro secured floating rate long term debt series C163 with a coupon rate 3 Month BA – 0.16% for CAD $200 million and a October 2, 2020 maturity date. CAD $192.75 million was swapped to USD $150 million floating rate debt to partially refinance debt series GE-2&3 (USD $250 million). A forward fixed interest rate swap that was previously linked to debt series GE-2&3 was re-linked to the C163 underlying refinancing which amended the fixed rate debt stream to 6.823% on USD $150 million (C163-A). The residual $7.25 million remained in CAD floating at 3BA – 0.16% (C163-B).

On June 4, 2018, a forward fixed interest rate swap that was previously linked to debt series GE-2&3 was re-linked to existing debt issues CO77-2 and CO77-3B which amended the fixed rate debt streams to 6.616% on USD $100 million. To accommodate the swap, on June 4, 2018, $128.5 million of existing floating rate long term debt series CO77-2 and CO77-3 was swapped to USD $100 million floating rate debt with a maturity date of February 11, 2020 to form debt series CO77-2 ($77,821,012) and C077-3B ($28,710,700).

On June 22, 2018, Manitoba Hydro secured long term debt series C160-2 for CAD $150 million and a March 5, 2068 maturity date. C160-2 was issued at a premium with proceeds of $151.5 million (net of commissions), a fixed rate coupon of 3.10%, and an all-in yield of 3.061%. The debt was issued to finance new borrowing requirements.

Quarter 2 On August 2, 2018, Manitoba Hydro secured long term debt series GV for CAD $400 million and a March 5, 2050 maturity date. GV was issued at a discount with proceeds of $395.4 million (net of commissions), a fixed rate coupon of 3.20%, and an all-in yield of 3.258%. The debt was issued to partially refinance $114.7 million of debt series GE as well as to refinance maturing $4.5 million of debt series HB12, with the residual $280.8 million being issued to finance new borrowing requirements.

On September 13, 2018, Manitoba Hydro secured long term debt series GV-2 for CAD $400 million and a March 5, 2050 maturity date. GV-2 was issued at a discount with proceeds of $395.9 million (net of commissions), a fixed rate coupon of 3.20%, and an all-in yield of 3.252%. The debt was issued to refinance $300 million of debt series GD as well as to partially refinance debt series EE ($95.9 million of total $228.4). The residual $4.1 million was issued to finance new borrowing requirements.

On September 19, 2018, Manitoba Hydro secured long term debt series GU-3 for CAD $150 million and a June 2, 2028 maturity date. GU-3 was issued at a discount with proceeds of $148.8 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.099%. The debt was issued to partially refinance debt series EE ($132.4 million of total $228.4 million), with the residual $17.6 million issued to finance new borrowing requirements.

Quarter 3 On October 22, 2018, Manitoba Hydro secured long term debt series GU-4 for CAD $150 million and a June 2, 2028 maturity date. GU-4 was issued at a discount with proceeds of $146.9 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.252%. The debt was issued to finance new borrowing requirements.

On November 30, 2018, Manitoba Hydro secured long term debt series GV-3 for CAD $150 million and a March 5, 2050 maturity date. GV-3 was issued at a discount with proceeds of $143.8 million (net of commissions), a fixed rate coupon of 3.20%, and an all-in yield of 3.415%. The debt was issued to finance new borrowing requirements.

b) Please see the following table for the long term debt maturity schedule as at December 31, 2018 for each debt series, identifying the currency for both interest and principal payments. This schedule excludes short term debt, which has a term to maturity at issuance of less than one year.

The Maturity Dates in the third column from the left conform to the Corporation's financial statement presentation, which in accordance with accounting standards, specify the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates).

The Action Dates in the fourth column from the left identify the maturities of the physical debt. Therefore, in cases where the maturity of underlying physical debt is before the linked forward interest rate swap for a debt series, a refinancing of the underlying physical debt will be required on the date highlighted in brown on the schedule.

The coupon rates (rounded to three decimal places for this schedule) identify the gross interest rates for each debt issue in its specified currency. The yield rates (rounded to three decimal places) conform to the Corporation's financial statement presentation, which in accordance with accounting standards show the effective all-in interest rate over the entire term of the debt issue (each debt issue in its specified currency). As floating rate debt will be subject to periodic interest rate resetting, the yield rate calculation for floating rate debt combines actual interest rates to the balance sheet date plus forecasted interest rates for the reminder of the time to the maturity date (utilizing the Corporation's forecasted interest rates for the variable component of the coupon payments).

The principal amounts are shown at par, with US dollar debt principal translated to CAD using the USD/CAD exchange rate on the balance sheet date.

MANITOBA HYDRO
Long Term Debt Maturity Schedule with Action and Swap Dates
At Dec 31, 2018
(in millions $; with USD/ CAD of 1.3642 at December 31, 2018)

Underlying physical debt matures before linked swap

New issuance

Debt Series	Currency (Int/ Princ)	Maturity Date	Action Date	Coupon Rate	Yield Rate	Principal (CAD)	Principal (USD)	Total Principal (CAD)
GQ-3	CAD/ CAD	11/21/19	11/21/19	3BA + 0.130%	1.864 %	24.2		24.2
CO77-3A	CAD/ CAD	02/11/20	02/11/20	2.150 %	3.021 %	21.5		21.5
C162-A	CAD/ CAD	03/15/20	03/15/20	5.796 %	5.796 %	25.2		25.2
C162-B	CAD/ CAD	03/15/20	03/15/20	5.796 %	5.796 %	49.5		49.5
C162-C	CAD/ CAD	03/15/20	03/15/20	5.796 %	5.796 %	47.6		47.6
C162-D	CAD/ USD	03/15/20	03/15/20	5.796 %	5.796 %		55.0	75.0
C162-E	CAD/ CAD	03/15/20	03/15/20	3BA - 0.1950%	1.914 %	7.3		7.3
C138-A	CAD/ CAD	05/15/20	05/15/20	3BA + 0.121%	4.733 %	100.0		100.0
C138-B	CAD/ CAD	05/15/20	05/15/20	3BA + 0.121%	4.813 %	100.0		100.0
FP-2	CAD/ CAD	06/03/20	06/03/20	4.150 %	4.244 %	125.0		125.0
FP-3	CAD/ CAD	06/03/20	06/03/20	4.150 %	3.469 %	250.0		250.0
CO77-2	CAD/ USD	10/02/20	02/11/20	6.616 %	3.437 %		77.8	106.2
CO77-3B	CAD/ USD	10/02/20	02/11/20	6.616 %	1.855 %		22.2	30.3
C163-A	CAD/ USD	10/02/20	10/02/20	6.823 %	6.823 %		150.0	204.6
C163-B	CAD/ CAD	10/02/20	10/02/20	3BA - 0.1600%	3.187 %	7.3		7.3
GM	CAD/ CAD	11/30/20	11/30/20	1.773 %	1.773 %	400.4		400.4
GO-3	CAD/ CAD	09/05/21	09/05/21	1.550 %	1.561 %	300.0		300.0
CO	USD/ USD	09/15/21	09/15/21	8.875 %	8.996 %		300.0	409.3
4A	CAD/ CAD	12/31/21	12/31/21	9.100 %	9.100 %	3.5		3.5
GQ-1	USD/ USD	02/01/22	11/21/19	6.484 %	6.484 %		350.0	477.5
GT	USD/ CAD	05/04/22	05/04/22	1.630 %	1.630 %	683.4		683.4
GC	CAD/ CAD	09/06/22	09/06/22	3BA + 0.499 %	2.231 %	296.4		296.4
GQ-2	USD/ USD	09/16/22	11/21/19	2.012 %	2.012 %		150.0	204.6
GF	CAD/ CAD	06/02/23	06/02/23	2.550 %	3.398 %	300.0		300.0
GH	CAD/ CAD	06/02/24	06/02/24	3.300 %	2.825 %	300.0		300.0
5C-1	CAD/ CAD	12/31/24	12/31/24	3.723 %	3.723 %	10.0		10.0
C140	CAD/ CAD	03/03/25	03/03/25	2.916 %	2.916 %	101.6		101.6
GJ-3	CAD/ CAD	06/02/25	06/02/25	2.450 %	2.549 %	150.0		150.0
GJ-4	CAD/ CAD	06/02/25	06/02/25	2.450 %	2.539 %	150.0		150.0
C119-2	CAD/ CAD	09/05/25	09/05/25	3BA + 0.425 %	2.223 %	150.0		150.0
DT	CAD/ CAD	12/22/25	12/22/25	7.750 %	7.952 %	170.0		170.0
DT-2	USD/ CAD	12/22/25	12/22/25	7.750 %	7.343 %	130.0		130.0
GN	CAD/ CAD	06/02/26	06/02/26	2.550 %	2.643 %	150.0		150.0
GN-3	CAD/ CAD	06/02/26	06/02/26	2.550 %	2.206 %	500.0		500.0
GN-4	CAD/ CAD	06/02/26	06/02/26	2.550 %	2.580 %	150.0		150.0
C145-4	CAD/ CAD	06/09/26	06/09/26	1.918 %	1.918 %	70.7		70.7
C145-5	CAD/ CAD	06/09/26	06/09/26	2.014 %	2.014 %	50.1		50.1
GP	CAD/ CAD	06/22/26	06/22/26	2.254 %	2.254 %	257.1		257.1
GS-C	CAD/ CAD	06/02/27	06/02/27	2.600 %	2.687 %	46.0		46.0
GS-2	CAD/ CAD	06/02/27	06/02/27	2.600 %	2.741 %	300.0		300.0
GS-3	CAD/ CAD	06/02/27	06/02/27	2.600 %	2.893 %	300.0		300.0
GS-4	CAD/ CAD	06/02/27	06/02/27	2.600 %	3.049 %	150.0		150.0
GS-5	CAD/ CAD	06/02/27	06/02/27	2.600 %	3.026 %	300.0		300.0
C157-3	CAD/ CAD	08/17/27	08/17/27	2.684 %	2.684 %	74.3		74.3
C157-4	CAD/ CAD	08/17/27	08/17/27	2.900 %	2.900 %	49.1		49.1
C157-5A	CAD/ CAD	08/17/27	08/17/27	3.058 %	3.058 %	63.9		63.9
C157-5B	CAD/ CAD	08/17/27	08/17/27	3BA + 0.2958%	3.032 %	9.9		9.9
GU	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.103 %	200.0		200.0
GU-2	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.195 %	350.0		350.0
GU-3	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.099 %	150.0		150.0
GU-4	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.252 %	150.0		150.0
C161-2	CAD/ CAD	08/22/28	08/22/28	2.903 %	2.903 %	50.0		50.0
4N	CAD/ CAD	02/02/29	02/02/29	5.900 %	5.900 %	30.0		30.0
4M	CAD/ CAD	02/02/29	02/02/29	5.900 %	5.900 %	30.0		30.0
C119-1	CAD/ CAD	09/01/29	09/05/25	6.575 %	6.575 %	100.0		100.0
5C-2	CAD/ CAD	12/31/29	12/31/29	4.049 %	4.049 %	10.0		10.0
CL	CAD/ CAD	03/05/31	03/05/31	10.500 %	10.796 %	300.0		300.0
CLW	CAD/ CAD	03/05/31	03/05/31	10.500 %	10.581 %	299.9		299.9
C116	CAD/ CAD	03/05/31	03/05/31	6.300 %	4.650 %	100.0		100.0
C148	CAD/ CAD	03/24/31	03/24/31	2.966 %	2.966 %	95.8		95.8
4B	CAD/ CAD	04/01/31	04/01/31	5.840 %	7.552 %	4.1		4.1
4C	CAD/ CAD	04/01/31	04/01/31	5.840 %	5.840 %	1.4		1.4
4Y	CAD/ CAD	05/01/31	05/01/31	5.650 %	7.390 %	4.9		4.9
CO52	CAD/ CAD	10/29/32	10/29/32	6.300 %	5.730 %	30.0		30.0
5C-3	CAD/ CAD	12/31/34	12/31/34	4.245 %	4.245 %	10.0		10.0
FP-1	CAD/ CAD	04/12/35	06/03/20	5.754 %	5.196 %	175.0		175.0
C135	CAD/ CAD	12/03/35	04/02/19	4.801 %	4.801 %	100.0		100.0
FA-1	CAD/ CAD	03/05/37	03/05/37	2.386 %	5.037 %	25.0		25.0
FA-2	CAD/ CAD	03/05/37	03/05/37	2.386 %	5.076 %	75.0		75.0
FA-3	CAD/ CAD	03/05/37	03/05/37	2.386 %	5.059 %	50.0		50.0
FA-4	CAD/ CAD	03/05/37	03/05/37	4.505 %	4.505 %	50.0		50.0
GO-2	CAD/ CAD	09/12/37	09/05/21	4.582 %	4.304 %	250.0		250.0
PB-2	CAD/ CAD	03/05/38	03/05/38	4.600 %	4.759 %	300.0		300.0
GS-A	CAD/ CAD	11/01/38	06/02/27	4.826 %	2.331 %	85.0		85.0
GS-B	CAD/ CAD	11/01/38	06/02/27	4.756 %	2.300 %	19.0		19.0

MANITOBA HYDRO
Long Term Debt Maturity Schedule with Action and Swap Dates
At Dec 31, 2018
(in millions $; with USD/ CAD of 1.3642 at December 31, 2018)

Underlying physical debt matures before linked swap

New issuance

Debt Series	Currency (Int/ Princ)	Maturity Date	Action Date	Coupon Rate	Yield Rate	Principal (CAD)	Principal (USD)	Total Principal (CAD)
C136-3	CAD/ CAD	11/01/38	09/05/29	5.058 %	5.058 %	31.0		31.0
C138-2	CAD/ CAD	11/01/38	05/15/20	4.897 %	4.897 %	50.0		50.0
C119-3C	CAD/ CAD	12/01/38	09/05/25	5.245 %	5.245 %	15.0		15.0
C119-3A	CAD/ CAD	12/01/38	09/05/25	5.245 %	5.245 %	50.0		50.0
C119-3B	CAD/ CAD	12/01/38	09/05/25	5.232 %	5.232 %	50.0		50.0
C136	CAD/ CAD	03/01/39	09/05/29	5.020 %	5.020 %	50.0		50.0
C136-2	CAD/ CAD	03/01/39	09/05/29	4.882 %	4.882 %	50.0		50.0
C154	CAD/ CAD	06/25/39	06/25/39	2.752 %	2.752 %	58.6		58.6
5C-4	CAD/ CAD	12/31/39	12/31/39	4.311 %	4.311 %	10.0		10.0
FK-2	CAD/ CAD	03/05/40	03/05/40	4.650 %	5.174 %	300.0		300.0
FR-2	CAD/ CAD	03/05/41	03/05/41	4.100 %	4.599 %	250.0		250.0
FR-3	CAD/ CAD	03/05/41	03/05/41	4.100 %	3.215 %	175.0		175.0
CO40	CAD/ CAD	03/05/42	03/05/42	3BA + 0.179 %	3.042 %	50.0		50.0
FT	CAD/ CAD	03/05/42	03/05/42	4.492 %	4.492 %	400.0		400.0
GA	CAD/ CAD	03/05/43	03/05/43	3.350 %	3.413 %	300.0		300.0
GA-2	CAD/ CAD	03/05/43	03/05/43	3.350 %	4.311 %	250.0		250.0
CO68	CAD/ CAD	03/05/44	03/05/44	3BA - 0.065 %	3.949 %	50.0		50.0
GG	CAD/ CAD	09/05/45	09/05/45	4.050 %	4.096 %	300.0		300.0
GG-2	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.819 %	250.0		250.0
GG-3	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.642 %	300.0		300.0
GG-4	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.589 %	400.0		400.0
C152	CAD/ CAD	08/08/46	08/08/46	2.778 %	2.778 %	50.8		50.8
C153	CAD/ CAD	08/30/46	08/30/46	2.801 %	2.801 %	76.3		76.3
GK	CAD/ CAD	09/05/46	09/05/46	2.850 %	2.902 %	300.0		300.0
GK-2	CAD/ CAD	09/05/46	09/05/46	2.850 %	2.898 %	300.0		300.0
GK-3	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.227 %	150.0		150.0
GK-4	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.526 %	300.0		300.0
GK-5	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.440 %	225.0		225.0
GK-6	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.275 %	150.0		150.0
GR-3	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.310 %	300.0		300.0
GR-4	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.495 %	300.0		300.0
GR-5	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.190 %	300.0		300.0
GR-6	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.186 %	300.0		300.0
GR-7	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.411 %	300.0		300.0
FN	CAD/ CAD	03/05/50	03/05/50	4.700 %	4.726 %	200.0		200.0
FN-2	CAD/ CAD	03/05/50	03/05/50	4.700 %	3.629 %	75.0		75.0
FN-3	CAD/ CAD	03/05/50	03/05/50	4.700 %	3.281 %	50.0		50.0
GV	CAD/ CAD	03/05/50	03/05/50	3.200 %	3.258 %	400.0		400.0
GV-2	CAD/ CAD	03/05/50	03/05/50	3.200 %	3.252 %	400.0		400.0
GV-3	CAD/ CAD	03/05/50	03/05/50	3.200 %	3.415 %	150.0		150.0
C129	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.178 %	50.0		50.0
C129-2	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.918 %	55.0		55.0
C129-3	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.065 %	50.0		50.0
C129-4	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.099 %	50.0		50.0
C129-5	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.087 %	50.0		50.0
C129-6	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.906 %	50.0		50.0
C129-7	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.915 %	20.0		20.0
C129-8	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.895 %	20.0		20.0
C129-9	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.858 %	60.0		60.0
C129-10	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.786 %	50.0		50.0
C129-11	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.702 %	25.0		25.0
C129-12	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.699 %	40.0		40.0
C139	CAD/ CAD	09/05/54	09/05/54	3.650 %	3.666 %	50.0		50.0
C139-2	CAD/ CAD	09/05/54	09/05/54	3.650 %	3.625 %	25.0		25.0
4Z	CAD/ CAD	06/09/57	06/09/57	7.100 %	7.100 %	7.0		7.0
C110	CAD/ CAD	03/05/60	03/05/60	5.200 %	4.629 %	125.0		125.0
C109	CAD/ CAD	03/05/63	03/05/63	4.625 %	4.638 %	50.0		50.0
C109-5	CAD/ CAD	03/05/63	03/05/63	4.625 %	3.597 %	50.0		50.0
C109-6	CAD/ CAD	03/05/63	03/05/63	4.625 %	3.555 %	50.0		50.0
C109-7	CAD/ CAD	03/05/63	03/05/63	4.625 %	3.506 %	50.0		50.0
C137-13	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.342 %	50.0		50.0
C137-16	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.163 %	150.0		150.0
C137	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.496 %	50.0		50.0
C137-2	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.887 %	25.0		25.0
C137-3	CAD/ CAD	03/05/63	03/05/63	3.450 %	4.019 %	37.0		37.0
C137-4	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.868 %	60.0		60.0
C137-5	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.354 %	50.0		50.0
C137-6	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.378 %	62.0		62.0
C137-7	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.502 %	75.0		75.0
C137-8	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.232 %	50.0		50.0
C137-9	CAD/ CAD	03/05/63	03/05/63	3.450 %	2.835 %	25.0		25.0
C137-10	CAD/ CAD	03/05/63	03/05/63	3.450 %	2.854 %	100.0		100.0
C137-11	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.457 %	100.0		100.0
C137-12	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.404 %	100.0		100.0
C160-2	CAD/ CAD	03/05/68	03/05/68	3.100 %	3.061 %	150.0		150.0
Total Long Term Debt						**19,146.7**	**1,105.0**	**20,654.1**

c) The following table details the debt issuance and corresponding interest rates:

Year	Debt Issued in year (millions)	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate MH93 (12 yr rate)	Notional Interest in year (millions)
2016	$ 2,208.2	3.87%	5.68%		$ 85.5
2017	$ 2,162.8	3.48%	5.41%		$ 75.3
2018	$ 3,380.6	3.67%	5.10%	3.40%	$ 124.2
2019	$ 3,950.0	4.36%	4.83%	3.85%	$ 172.4
2020	$ 2,400.0	4.89%	4.77%	4.29%	$ 117.3
Total	$ 14,101.6				$ 574.5

Note 1: Debt Issued excludes refinancing of underling debt linked to ongoing interest rate swaps

Note 2: All rates include 1% PGF

Note 3: 2018 represents actual debt issuance for the fiscal year and excludes $150 million of forecast debt issuance in the Outlook.
2019 debt issuance includes $150 million carried over from 2018 forecast debt issuance.

The information requested for the period beyond the 2019/20 test year is not available at the current time. The assumptions underpinning the requested information will be considered in the context of the MHEB's approval of the Corporation's next Integrated Financial Forecast and provided in Manitoba Hydro's next full GRA.

d) This response assumes the requested comparison is to the updated table shown in part c) of this Information Request and not part e), as listed in the question. As noted in the response to part c), the information requested for the period beyond the 2019/20 test year is not available at the current time.

The table from PUB-MH I-32b from the 2017/18 & 2018/19 GRA showed only the forecast debt remaining to be issued for the fiscal year 2018. For completeness, the fiscal 2018 data from PUB-MH I-32b has been restated to include actual debt issuance in addition to the previously reported forecast debt issuance. The restated table is as follows:

Year	Debt Issued in year (millions)	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate MH93 (12 yr rate)	Notional Interest in year (millions)
2018	$ 3,433.4	3.17%	5.13%	3.40%	$ 108.8
2019	$ 3,600.0	3.85%	4.71%	3.85%	$ 138.6
2020	$ 2,200.0	4.29%	4.61%	4.29%	$ 94.4

A table showing the differences between the restated PUB-MH I-32b and part c) of this response is as follows:

Year	Debt Issued in year (millions)	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate MH93 (12 yr rate)	Notional Interest in year (millions)
2018	$ (52.8)	0.50%	-0.03%		$ 15.4
2019	$ 350.0	0.41%	0.12%		$ 29.8
2020	$ 200.0	0.60%	0.16%		$ 22.9
Total	$ 497.2				$ 68.1

Fiscal 2018: The volume of debt issued for the fiscal year was approximately $53 million lower than forecast in MH93 and the weighted average interest rate (WAIR) was 0.50% higher. However, the WAIR on all outstanding debt at year end was relatively unchanged due to timing of the actual debt issuances. The notional interest on debt issued in the year was $15.4 million higher than forecast in MH93.

Fiscal 2019: The 2018/19 Outlook forecasts that the volume of debt issuance will exceed the MH93 forecast by $350 million, including $150 million which has been carried over from forecast debt issuance in fiscal 2018 due to timing differences. Lower net export revenues and higher financing costs are contributing to the increased cash requirements in the 2018/19 Outlook. The WAIR is forecast to be higher by 0.41% due to higher consensus forecast interest rates and a change in terming strategy for new debt issuance amending the forecast weighted average term to maturity (WATM) from 12 years in MH93 to 20 years in the 2018/19 Outlook. Subsequent to the filing of MH93 and during the course of the 2017/18 & 2018/19 GRA, the Bank of Canada interest rates rose such that the cost advantage to borrowing shorter term maturities did not materialize. The yield curve continued to flatten such that there is now only a minimal difference between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. Considering this interest rate environment , Manitoba Hydro reverted to a longer term borrowing strategy of targeting a 20 year WATM for new borrowings as opposed to the 12 year assumption in MH93. These differences resulted in the forecast WAIR on all outstanding debt being 0.12% higher by yearend and a $29.8 million increase in notional interest on debt issued within the year.

Fiscal 2020: The 2019/20 Interim Budget forecasts that the volume of debt issuance will exceed the MH93 forecast by $200 million. The WAIR is forecast to be higher by 0.60% due to higher consensus forecast interest rates and a change in terming strategy for new debt issuance amending the forecast weighted average term to maturity (WATM) from 12 years in MH93 to 20 years in the 2019/20 Interim Budget. These differences resulted in the forecast WAIR on all outstanding debt being 0.16% higher by yearend and a $22.9 million increase in notional interest on debt issued within the year.

e) The following table provides a schedule detailing the current refinancing plans, the weighted average term of outstanding debt, the principle amount and proportions of debt maturing in 10 years, 20 years and greater than 20 years as projected at the end of 2019/20.

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PUB-Mh I-38 e) - Finance Expense - Debt Levels

Actuals are shown for March 31, 2004 - 2018; with forecast information shown for March 31, 2019 & 2020.

($ in CAD millions)

	Debt Maturing Less than 10 Years		Debt Maturing Between 10 - 20 Years		Debt Maturing Greater than 20 Years		Total Long Term Debt	Weighted Average Term to Maturity
	$	% of Total	$	% of Total	$	% of Total	$	(Years)
March 31, 2004	2,586	35.1 %	3,521	47.7 %	1,268	17.2 %	7,375	13.8
March 31, 2005	2,377	33.1 %	3,346	46.5 %	1,468	20.4 %	7,191	13.8
March 31, 2006	2,397	33.5 %	3,317	46.3 %	1,443	20.2 %	7,158	13.7
March 31, 2007	2,623	36.3 %	3,094	42.9 %	1,501	20.8 %	7,218	12.9
March 31, 2008	2,996	39.5 %	2,513	33.1 %	2,081	27.4 %	7,590	13.5
March 31, 2009	3,763	45.8 %	2,026	24.7 %	2,421	29.5 %	8,209	13.6
March 31, 2010	3,963	46.0 %	1,805	21.0 %	2,846	33.0 %	8,614	14.8
March 31, 2011	3,967	45.6 %	2,241	25.7 %	2,496	28.7 %	8,704	15.3
March 31, 2012	4,841	51.4 %	1,619	17.2 %	2,962	31.4 %	9,422	14.9
March 31, 2013	5,179	51.7 %	1,499	15.0 %	3,332	33.3 %	10,010	14.8
March 31, 2014	5,160	46.9 %	1,500	13.6 %	4,349	39.5 %	11,009	16.2
March 31, 2015	5,264	41.4 %	1,370	10.8 %	6,084	47.8 %	12,717	17.8
March 31, 2016	6,096	41.7 %	1,441	9.9 %	7,071	48.4 %	14,607	18.1
March 31, 2017	7,270	44.1 %	1,641	9.9 %	7,582	46.0 %	16,492	17.5
March 31, 2018	8,716	45.3 %	2,091	10.9 %	8,432	43.8 %	19,239	17.2
March 31, 2019 *	8,781	40.0 %	3,767	17.1 %	9,432	42.9 %	21,980	17.6
March 31, 2020 *	8,634	35.8 %	6,425	26.6 %	9,063	37.6 %	24,122	17.0

* The forecasted debt percentages and weighted average terms to maturity will be affected by the simplifying modeling assumption of a 20 year term to maturity for all new debt issuance. Actual terms to maturity will vary from forecast.

REFERENCE:

Application pg.8; 2017/18 GRA PUB/MH I-32a-b, PUB MFR 57, 58, and 59

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide the term sheets of amended long term debt issuance since the last GRA for the years 2017/18 and 2018/19.
b) Provide a listing of debt issued in same format of PUB MFR 58 from the 2017/18 & 2018/19 GRA and highlight any new issuances since the last GRA.
c) Provide an update and complete the following table detailing the debt issuance and corresponding interest rates.

Year	Debt Issued in year	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate IFF 16 Updated (MH93)	Notional Interest
2016	2,208.2	3.87%	5.68%		$85.5
2017	2,162.8	3.48%	5.41%		$75.3
2018					
2019					
2020					
2021					
2022					
2023					
Total					

d) Provide a comparison of the actual and forecast amounts for the years 2018 through 2023 from the table in (e) with PUB/MH 1-32 b (2017/18 & 2018/19 GRA) and explain the differences.
e) Provide in a similar format to MFR 59 a schedule detailing the current refinancing plans, the weighted average term of outstanding debt, the principle amount and proportions

of debt maturing in 10 years, 20 years and greater than 20 years as projected at the end of 2019/20.

RESPONSE:

a) The terms for Manitoba Hydro's new and amended long term debt financings are provided for fiscal years 2017/18 and 2018/19 to February 28, 2019 below.

2017/18 The actual long term financings for the year are CAD $3,380.6 million made up of:

- $2,982.9 million for new borrowing requirements.
- $147.7 million to refinance maturing long term debt.
- $250.0 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year, per quarter, are as follows:

Quarter 1 On April 3, 2017, Manitoba Hydro secured long term debt series C137-13 for CAD $50 million and a March 5, 2063 maturity date. C137-13 was issued at a premium with proceeds of $51.2 million (net of commissions), a fixed rate coupon of 3.45%, and an all-in yield of 3.342%. The debt was issued to finance new borrowing requirements.

On May 4, 2017, Manitoba Hydro secured long term debt series GT for USD $500 million and a May 4, 2022 maturity date. The issue was swapped to CAD $683.4 million and a fixed rate coupon of 1.630%. The debt was issued to finance new borrowing requirements.

On May 5, 2017, Manitoba Hydro secured long term debt series GO-3 for CAD $300 million and a September 5, 2021 maturity date. GO-3 was issued at a discount with proceeds of $299.9 million (net of commissions), a fixed rate

coupon of 1.55%, and an all-in yield of 1.561%. The debt was issued to finance new borrowing requirements.

Quarter 2 On July 11, 2017, Manitoba Hydro secured long term debt series C137-16 for CAD $150 million and a March 5, 2063 maturity date. C137-16 was issued at a premium with proceeds of $160.4 million (net of commissions), a fixed rate coupon of 3.45%, and an all-in yield of 3.163%. The debt was issued to finance new borrowing requirements.

On July 28, 2017, Manitoba Hydro secured long term debt series GR-3 for CAD $300 million and a September 5, 2048 maturity date. GR-3 was issued at a premium with proceeds of $305.2 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.310%. The debt was issued to refinance $2.2 million of HydroBonds Series 12 five year floating rate debt early redemptions. The remaining $297.8 million of the debt was issued to finance new borrowing requirements.

On August 21, 2017, Manitoba Hydro secured long term debt series GS-2 for CAD $300 million and a June 2, 2027 maturity date. GS-2 was issued at a discount with proceeds of $296.4 million (net of commissions), a fixed rate coupon of 2.60%, and an all-in yield of 2.741%. The debt was issued to finance new borrowing requirements.

On September 7, 2017, Manitoba Hydro secured long term debt series C157-3 for AUD $75 million and an August 17, 2027 maturity date. The issue was swapped to CAD $74.3 million and a fixed rate coupon of 2.684%. The debt was issued to finance new borrowing requirements.

Quarter 3 On October 2, 2017, Manitoba Hydro secured long term debt series GR-4 for CAD $300 million and a September 5, 2048 maturity date. GR-4 was issued at a discount with proceeds of $294.6 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.495%. The debt was issued to refinance $250 million of maturing debt series FJ. A forward fixed interest rate swap that was previously linked to debt issue FJ was re-linked to existing series

GO-2 underlying refinancing, which amended the fixed rate on $250 million of the debt stream to 4.582%. The remaining $50 million of the debt was issued to finance new borrowing requirements.

On October 5, 2017, Manitoba Hydro secured long term debt series C157-4 for AUD $50 million and an August 17, 2027 maturity date. The issue was swapped to CAD $49.1 million and a fixed rate coupon of 2.900%. The debt was issued to finance new borrowing requirements.

On November 23, 2017, Manitoba Hydro secured long term debt series GR-5 for CAD $300 million and a September 5, 2048 maturity date. GR-5 was issued at a premium with proceeds of $312.3 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.190%. The debt was issued to refinance $55.5 million of maturing debt series C-011. The remaining $244.5 million of the debt was issued to finance new borrowing requirements.

Quarter 4 On January 1, 2018, Manitoba Hydro secured long term debt series GS-3 for CAD $300 million and a June 2, 2027 maturity date. GS-3 was issued at a discount with proceeds of $298.8 million (net of commissions), a fixed rate coupon of 2.60% and an all-in yield of 2.893%. The debt was issued to refinance $90 million (of total $255.0 million) of maturing debt series BM. The remaining $210 million of the debt was issued to finance new borrowing requirements.

On February 2, 2018, Manitoba Hydro secured long term debt series GR-6 for CAD $300 million and a September 5, 2048 maturity date. GR-6 was issued at premium with proceeds of $312.5 million (net of commissions), a fixed rate coupon of 3.40% and an all-in yield of 3.186%. The debt was issued to finance new borrowing requirements.

On February 15, 2018, Manitoba Hydro secured long term debt series GS-4 for CAD $150 million and a June 2, 2027 maturity date. GS-4 was issued at a discount with proceeds of $144.6 million (net of commissions), a fixed rate coupon of 2.60% and an all-in yield of 3.049%. The debt was issued to finance new borrowing requirements.

On February 20, 2018, Manitoba Hydro secured long term debt series C157-5 for AUD $75 million and an August 17, 2027 maturity date. The issue was swapped to CAD $63.9 million (C157-5A) and a fixed rate coupon of 3.058% as well as CAD $9.9 million (C157-5B) and a floating rate coupon of 3M BA + 0.2958%. The debt was issued to finance new borrowing requirements.

On March 9, 2018, Manitoba Hydro secured long term debt series C161-2 for AUD $50 million and an August 22, 2028 maturity date. The issue was swapped to CAD $50 million and a fixed rate coupon of 2.903%. The debt was issued to finance new borrowing requirements.

2018/19 The actual long term financings for the year to date are CAD $3,810.7 million made up of:

- $2,385.4 million for new borrowing requirements.
- $1,039.8 million to refinance maturing long term debt.
- $385.5 million to refinance maturing underlying debt issues associated with ongoing interest rate swaps.

The actual long term debt financings undertaken during this fiscal year to February 28, 2019, per quarter, including C167 and C168 that settle March 15, 2019, are as follows:

Quarter 1 On April 9, 2018, Manitoba Hydro secured long term debt series GS-5 for CAD $300 million and a June 2, 2027 maturity date. GS-5 was issued at a discount with proceeds of $289.9 million (net of commissions), a fixed rate coupon of 2.60%, and an all-in yield of 3.026%. The debt was issued to refinance $85 million of Series C132-2A, $19 million of Series C132-2B and $185.9 million (of total $200 million) of Series C132. The remaining $10.1 million of the debt was issued to finance new borrowing requirements. Forward fixed interest rate swaps that were previously linked to debt series C132-2A ($85 million) and

C132-2B ($19 million) were re-linked to existing series GS which amended the fixed rates on $85 million of the debt stream to 4.826% and on $19 million of the debt stream to 4.756%.

On April 17, 2018, Manitoba Hydro secured long term debt series GU for CAD $200 million and a June 2, 2028 maturity date. GU was issued at a discount with proceeds of $198.2 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.103%. The debt was issued to finance new borrowing requirements.

On May 4, 2018, Manitoba Hydro secured long term debt series GU-2 for CAD $350 million and a June 2, 2028 maturity date. GU-2 was issued at a discount with proceeds of $344.1 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.195%. The debt was issued to refinance $14.1 million (of total $200 million) of Series C132. The remaining $335.9 million was issued to finance new borrowing requirements.

On May 22, 2018, Manitoba Hydro secured long term debt series GR-7 for CAD $300 million and a September 5, 2048 maturity date. GR-7 was issued at a discount with proceeds of $299.4 million (net of commissions), a fixed rate coupon of 3.40%, and an all-in yield of 3.411%. The debt was issued to finance new borrowing requirements.

On June 1, 2018, Manitoba Hydro secured floating rate long term debt series C162 with a coupon rate of 3 Month BA – 0.195% for CAD $200 million and a March 15, 2020 maturity date. CAD $192.75 million was swapped to USD $150 million floating rate debt to refinance debt series GE-1. A forward fixed interest rate swap that was previously linked to debt series GE-1 was re-linked to the C162 underlying refinancing which amended the fixed rate debt stream to 5.796% on USD $150,000,000 (C162-D). The residual $7.25 million remained in CAD floating at 3BA – 0.195% (C162-E).

On June 1, 2018, Manitoba Hydro secured floating rate long term debt series C163 with a coupon rate 3 Month BA – 0.16% for CAD $200 million and a

October 2, 2020 maturity date. CAD $192.75 million was swapped to USD $150 million floating rate debt to partially refinance debt series GE-2&3 (USD $250 million). A forward fixed interest rate swap that was previously linked to debt series GE-2&3 was re-linked to the C163 underlying refinancing which amended the fixed rate debt stream to 6.823% on USD $150 million (C163-A). The residual $7.25 million remained in CAD floating at 3BA – 0.16% (C163-B).

On June 4, 2018, a forward fixed interest rate swap that was previously linked to debt series GE-2&3 was re-linked to existing debt issues CO77-2 and CO77-3B which amended the fixed rate debt streams to 6.616% on USD $100 million. To accommodate the swap, on June 4, 2018, $128.5 million of existing floating rate long term debt series CO77-2 and CO77-3 was swapped to USD $100 million floating rate debt with a maturity date of February 11, 2020 to form debt series CO77-2 ($77,821,012) and C077-3B ($28,710,700).

On June 22, 2018, Manitoba Hydro secured long term debt series C160-2 for CAD $150 million and a March 5, 2068 maturity date. C160-2 was issued at a premium with proceeds of $151.5 million (net of commissions), a fixed rate coupon of 3.10%, and an all-in yield of 3.061%. The debt was issued to finance new borrowing requirements.

Quarter 2 On August 2, 2018, Manitoba Hydro secured long term debt series GV for CAD $400 million and a March 5, 2050 maturity date. GV was issued at a discount with proceeds of $395.4 million (net of commissions), a fixed rate coupon of 3.20%, and an all-in yield of 3.258%. The debt was issued to partially refinance $114.7 million of debt series GE as well as to refinance maturing $4.5 million of debt series HB12, with the residual $280.8 million being issued to finance new borrowing requirements.

On September 13, 2018, Manitoba Hydro secured long term debt series GV-2 for CAD $400 million and a March 5, 2050 maturity date. GV-2 was issued at a discount with proceeds of $395.9 million (net of commissions), a fixed rate coupon of 3.20%, and an all-in yield of 3.252%. The debt was issued to refinance $300 million of debt series GD as well as to partially refinance debt series EE ($95.9 million of total $228.4). The residual $4.1 million was issued to finance new borrowing requirements.

On September 19, 2018, Manitoba Hydro secured long term debt series GU-3 for CAD $150 million and a June 2, 2028 maturity date. GU-3 was issued at a discount with proceeds of $148.8 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.099%. The debt was issued to partially refinance debt series EE ($132.4 million of total $228.4 million), with the residual $17.6 million issued to finance new borrowing requirements.

Quarter 3 On October 22, 2018, Manitoba Hydro secured long term debt series GU-4 for CAD $150 million and a June 2, 2028 maturity date. GU-4 was issued at a discount with proceeds of $146.9 million (net of commissions), a fixed rate coupon of 3.00%, and an all-in yield of 3.252%. The debt was issued to finance new borrowing requirements.

On November 30, 2018, Manitoba Hydro secured long term debt series GV-3 for CAD $150 million and a March 5, 2050 maturity date. GV-3 was issued at a discount with proceeds of $143.8 million (net of commissions), a fixed rate coupon of 3.20%, and an all-in yield of 3.415%. The debt was issued to finance new borrowing requirements.

Quarter 4 On January 25, 2019, Manitoba Hydro secured long term debt series C166 for GBP $100 million and a December 15, 2022 maturity date. The issue was swapped to CAD $171.2 million and a fixed rate coupon of 2.550% on CAD $151.2 million and 3BA + 0.175% on CAD $20 million. The debt was issued to refinance $69.3 million of maturing debt series BU, $1 million of maturing series 3W and $3.5 million of maturing series 3V with the remaining $97.4 million to finance new borrowing requirements.

On February 11, 2019, Manitoba Hydro secured long term debt series GW for CAD $150 million and a June 2, 2029 maturity date. GW was issued at a discount with proceeds of $148.8 million (net of commissions), a fixed rate

coupon of 2.75%, and an all-in yield of 2.842%. The debt was issued to finance new borrowing requirements.

On February 26, 2019, Manitoba Hydro secured long term debt series C160-4 for CAD $25 million and a March 5, 2068 maturity date. C160-4 was issued at a discount with proceeds of $24.7 million (net of commissions), a fixed rate coupon of 3.10%, and an all-in yield of 3.150%. The debt was issued to finance new borrowing requirements.

On February 27, 2019, Manitoba Hydro secured long term debt series GF-5 for CAD $250 million and a June 2, 2023 maturity date. GF-5 was issued at a premium with proceeds of $252.2 million (net of commissions), a fixed rate coupon of 2.55%, and an all-in yield of 2.333%. The debt was issued to finance new borrowing requirements.

Settling on March 15, 2019, Manitoba Hydro secured long term debt series C167 for CHF 125 million and a March 15, 2029 maturity date. The issue was swapped to CAD $165.3 million and a floating rate coupon of 3BA + 0.474%. The debt was issued to finance new borrowing requirements.

Settling on March 15, 2019, Manitoba Hydro secured long term debt series C168 for CHF 75 million and a March 15, 2039 maturity date. The issue was swapped to CAD $99.2 million and a fixed rate coupon of 3.241%. The debt was issued to finance new borrowing requirements.

b) Please see the following table for the long term debt maturity schedule as at February 28, 2019 for each debt series, including C167 and C168 which settle on March 15, 2019, identifying the currency for both interest and principal payments. This schedule excludes short term debt, which has a term to maturity at issuance of less than one year.

The Maturity Dates in the third column from the left conform to the Corporation's financial statement presentation, which in accordance with accounting standards, specify the most outward obligation dates on any debt series (the latter of physical debt or forward interest rate swap maturity dates).

The Action Dates in the fourth column from the left identify the maturities of the physical debt. Therefore, in cases where the maturity of underlying physical debt is before the linked forward interest rate swap for a debt series, a refinancing of the underlying physical debt will be required on the date highlighted in brown on the schedule.

The coupon rates (rounded to three decimal places for this schedule) identify the gross interest rates for each debt issue in its specified currency. The yield rates (rounded to three decimal places) conform to the Corporation's financial statement presentation, which in accordance with accounting standards show the effective all-in interest rate over the entire term of the debt issue (each debt issue in its specified currency). As floating rate debt will be subject to periodic interest rate resetting, the yield rate calculation for floating rate debt combines actual interest rates to the balance sheet date plus forecasted interest rates for the reminder of the time to the maturity date (utilizing the Corporation's forecasted interest rates for the variable component of the coupon payments).

The principal amounts are shown at par, with US dollar debt principal translated to CAD using the USD/CAD exchange rate on the balance sheet date.

MANITOBA HYDRO
Long Term Debt Maturity Schedule with Action and Swap Dates
At Feb 28, 2019
(in millions $; with USD/ CAD of 1.3169 at February 28, 2019)

Underlying physical debt matures before linked swap

New issuance

Debt Series	Currency (Int/ Princ)	Maturity Date	Action Date	Coupon Rate	Yield Rate	Principal (CAD)	Principal (USD)	Total Principal (CAD)
GQ-3	CAD/ CAD	11/21/19	11/21/19	3BA + 0.130%	1.864 %	24.2		24.2
CO77-3A	CAD/ CAD	02/11/20	02/11/20	2.150 %	3.021 %	21.5		21.5
C162-A	CAD/ CAD	03/15/20	03/15/20	5.796 %	5.796 %	25.2		25.2
C162-B	CAD/ CAD	03/15/20	03/15/20	5.796 %	5.796 %	49.5		49.5
C162-C	CAD/ CAD	03/15/20	03/15/20	5.796 %	5.796 %	47.6		47.6
C162-D	CAD/ USD	03/15/20	03/15/20	5.796 %	5.796 %		55.0	72.4
C162-E	CAD/ CAD	03/15/20	03/15/20	3BA - 0.1950%	1.914 %	7.3		7.3
C138-A	CAD/ CAD	05/15/20	05/15/20	3BA + 0.121%	4.733 %	100.0		100.0
C138-B	CAD/ CAD	05/15/20	05/15/20	3BA + 0.121%	4.813 %	100.0		100.0
FP-2	CAD/ CAD	06/03/20	06/03/20	4.150 %	4.244 %	125.0		125.0
FP-3	CAD/ CAD	06/03/20	06/03/20	4.150 %	3.469 %	250.0		250.0
CO77-2	CAD/ USD	10/02/20	02/11/20	6.616 %	3.437 %		77.8	102.5
CO77-3B	CAD/ USD	10/02/20	02/11/20	6.616 %	1.855 %		22.2	29.2
C163-A	CAD/ USD	10/02/20	10/02/20	6.823 %	6.823 %		150.0	197.5
C163-B	CAD/ CAD	10/02/20	10/02/20	3BA - 0.1600%	3.187 %	7.3		7.3
GM	CAD/ CAD	11/30/20	11/30/20	1.773 %	1.773 %	400.4		400.4
GO-3	CAD/ CAD	09/05/21	09/05/21	1.550 %	1.561 %	300.0		300.0
CO	USD/ USD	09/15/21	09/15/21	8.875 %	8.996 %		300.0	395.1
4A	CAD/ CAD	12/31/21	12/31/21	9.100 %	9.100 %	3.5		3.5
GQ-1	USD/ USD	02/01/22	11/21/19	6.484 %	6.484 %		350.0	460.9
GT	USD/ CAD	05/04/22	05/04/22	1.630 %	1.630 %	683.4		683.4
GC	CAD/ CAD	09/06/22	09/06/22	3BA + 0.499 %	2.231 %	296.4		296.4
GQ-2	USD/ USD	09/16/22	11/21/19	2.012 %	2.012 %		150.0	197.5
C166-A	CAD/ CAD	12/15/22	12/15/22	2.550 %	2.550 %	151.2		151.2
C166-B	CAD/ CAD	12/15/22	12/15/22	3BA + 0.175%	2.734 %	20.0		20.0
GF	CAD/ CAD	06/02/23	06/02/23	2.550 %	3.398 %	300.0		300.0
GF-5	CAD/ CAD	06/02/23	06/02/23	2.550 %	2.333 %	250.0		250.0
GH	CAD/ CAD	06/02/24	06/02/24	3.300 %	2.825 %	300.0		300.0
5C-1	CAD/ CAD	12/31/24	12/31/24	3.723 %	3.723 %	10.0		10.0
C140	CAD/ CAD	03/03/25	03/03/25	2.916 %	2.916 %	101.6		101.6
GJ-3	CAD/ CAD	06/02/25	06/02/25	2.450 %	2.549 %	150.0		150.0
GJ-4	CAD/ CAD	06/02/25	06/02/25	2.450 %	2.539 %	150.0		150.0
C119-2	CAD/ CAD	09/05/25	09/05/25	3BA + 0.425 %	2.223 %	150.0		150.0
DT	CAD/ CAD	12/22/25	12/22/25	7.750 %	7.952 %	170.0		170.0
DT-2	USD/ CAD	12/22/25	12/22/25	7.750 %	7.343 %	130.0		130.0
GN	CAD/ CAD	06/02/26	06/02/26	2.550 %	2.643 %	150.0		150.0
GN-3	CAD/ CAD	06/02/26	06/02/26	2.550 %	2.206 %	500.0		500.0
GN-4	CAD/ CAD	06/02/26	06/02/26	2.550 %	2.580 %	150.0		150.0
C145-4	CAD/ CAD	06/09/26	06/09/26	1.918 %	1.918 %	70.7		70.7
C145-5	CAD/ CAD	06/09/26	06/09/26	2.014 %	2.014 %	50.1		50.1
GP	CAD/ CAD	06/22/26	06/22/26	2.254 %	2.254 %	257.1		257.1
GS-C	CAD/ CAD	06/02/27	06/02/27	2.600 %	2.687 %	46.0		46.0
GS-2	CAD/ CAD	06/02/27	06/02/27	2.600 %	2.741 %	300.0		300.0
GS-3	CAD/ CAD	06/02/27	06/02/27	2.600 %	2.893 %	300.0		300.0
GS-4	CAD/ CAD	06/02/27	06/02/27	2.600 %	3.049 %	150.0		150.0
GS-5	CAD/ CAD	06/02/27	06/02/27	2.600 %	3.026 %	300.0		300.0
C157-3	CAD/ CAD	08/17/27	08/17/27	2.684 %	2.684 %	74.3		74.3
C157-4	CAD/ CAD	08/17/27	08/17/27	2.900 %	2.900 %	49.1		49.1
C157-5A	CAD/ CAD	08/17/27	08/17/27	3.058 %	3.058 %	63.9		63.9
C157-5B	CAD/ CAD	08/17/27	08/17/27	3BA + 0.2958%	3.032 %	9.9		9.9
GU	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.103 %	200.0		200.0
GU-2	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.195 %	350.0		350.0
GU-3	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.099 %	150.0		150.0
GU-4	CAD/ CAD	06/02/28	06/02/28	3.000 %	3.252 %	150.0		150.0
C161-2	CAD/ CAD	08/22/28	08/22/28	2.903 %	2.903 %	50.0		50.0
4N	CAD/ CAD	02/02/29	02/02/29	5.900 %	5.900 %	30.0		30.0
4M	CAD/ CAD	02/02/29	02/02/29	5.900 %	5.900 %	30.0		30.0
C167	CAD/ CAD	03/15/29	03/15/29	3BA + 0.474%	3.340 %	165.3		165.3
GW	CAD/ CAD	06/02/29	06/02/29	2.750 %	2.842 %	150.0		150.0
C119-1	CAD/ CAD	09/01/29	09/05/25	6.575 %	6.575 %	100.0		100.0
5C-2	CAD/ CAD	12/31/29	12/31/29	4.049 %	4.049 %	10.0		10.0
CL	CAD/ CAD	03/05/31	03/05/31	10.500 %	10.796 %	300.0		300.0
CLW	CAD/ CAD	03/05/31	03/05/31	10.500 %	10.581 %	299.9		299.9
C116	CAD/ CAD	03/05/31	03/05/31	6.300 %	4.650 %	100.0		100.0
C148	CAD/ CAD	03/24/31	03/24/31	2.966 %	2.966 %	95.8		95.8
4B	CAD/ CAD	04/01/31	04/01/31	5.840 %	7.552 %	4.1		4.1
4C	CAD/ CAD	04/01/31	04/01/31	5.840 %	5.840 %	1.4		1.4
4Y	CAD/ CAD	05/01/31	05/01/31	5.650 %	7.390 %	4.9		4.9
CO52	CAD/ CAD	10/29/32	10/29/32	6.300 %	5.730 %	30.0		30.0
5C-3	CAD/ CAD	12/31/34	12/31/34	4.245 %	4.245 %	10.0		10.0
FP-1	CAD/ CAD	04/12/35	06/03/20	5.754 %	5.196 %	175.0		175.0
C135	CAD/ CAD	12/03/35	04/02/19	4.801 %	4.801 %	100.0		100.0
FA-1	CAD/ CAD	03/05/37	03/05/37	2.386 %	5.037 %	25.0		25.0
FA-2	CAD/ CAD	03/05/37	03/05/37	2.386 %	5.076 %	75.0		75.0
FA-3	CAD/ CAD	03/05/37	03/05/37	2.386 %	5.059 %	50.0		50.0
FA-4	CAD/ CAD	03/05/37	03/05/37	4.505 %	4.505 %	50.0		50.0
GO-2	CAD/ CAD	09/12/37	09/05/21	4.582 %	4.304 %	250.0		250.0
PB-2	CAD/ CAD	03/05/38	03/05/38	4.600 %	4.759 %	300.0		300.0
GS-A	CAD/ CAD	11/01/38	06/02/27	4.826 %	2.331 %	85.0		85.0
GS-B	CAD/ CAD	11/01/38	06/02/27	4.756 %	2.300 %	19.0		19.0

MANITOBA HYDRO
Long Term Debt Maturity Schedule with Action and Swap Dates
At Dec 31, 2018
(in millions $; with USD/ CAD of 1.3169 at February 28, 2019)

Underlying physical debt matures before linked swap

New issuance

Debt Series	Currency (Int/ Princ)	Maturity Date	Action Date	Coupon Rate	Yield Rate	Principal (CAD)	Principal (USD)	Total Principal (CAD)
C136-3	CAD/ CAD	11/01/38	09/05/29	5.058 %	5.058 %	31.0		31.0
C138-2	CAD/ CAD	11/01/38	05/15/20	4.897 %	4.897 %	50.0		50.0
C119-3C	CAD/ CAD	12/01/38	09/05/25	5.245 %	5.245 %	15.0		15.0
C119-3A	CAD/ CAD	12/01/38	09/05/25	5.245 %	5.245 %	50.0		50.0
C119-3B	CAD/ CAD	12/01/38	09/05/25	5.232 %	5.232 %	50.0		50.0
C136	CAD/ CAD	03/01/39	09/05/29	5.020 %	5.020 %	50.0		50.0
C136-2	CAD/ CAD	03/01/39	09/05/29	4.882 %	4.882 %	50.0		50.0
C168	CAD/ CAD	03/15/39	03/15/39	3.241 %	3.241 %	99.2		99.2
C154	CAD/ CAD	06/25/39	06/25/39	2.752 %	2.752 %	58.6		58.6
5C-4	CAD/ CAD	12/31/39	12/31/39	4.311 %	4.311 %	10.0		10.0
FK-2	CAD/ CAD	03/05/40	03/05/40	4.650 %	5.174 %	300.0		300.0
FR-2	CAD/ CAD	03/05/41	03/05/41	4.100 %	4.599 %	250.0		250.0
FR-3	CAD/ CAD	03/05/41	03/05/41	4.100 %	3.215 %	175.0		175.0
CO40	CAD/ CAD	03/05/42	03/05/42	3BA + 0.179 %	3.042 %	50.0		50.0
FT	CAD/ CAD	03/05/42	03/05/42	4.492 %	4.492 %	400.0		400.0
GA	CAD/ CAD	03/05/43	03/05/43	3.350 %	3.413 %	300.0		300.0
GA-2	CAD/ CAD	03/05/43	03/05/43	3.350 %	4.311 %	250.0		250.0
CO68	CAD/ CAD	03/05/44	03/05/44	3BA - 0.065 %	3.949 %	50.0		50.0
GG	CAD/ CAD	09/05/45	09/05/45	4.050 %	4.096 %	300.0		300.0
GG-2	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.819 %	250.0		250.0
GG-3	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.642 %	300.0		300.0
GG-4	CAD/ CAD	09/05/45	09/05/45	4.050 %	3.589 %	400.0		400.0
C152	CAD/ CAD	08/08/46	08/08/46	2.778 %	2.778 %	50.8		50.8
C153	CAD/ CAD	08/30/46	08/30/46	2.801 %	2.801 %	76.3		76.3
GK	CAD/ CAD	09/05/46	09/05/46	2.850 %	2.902 %	300.0		300.0
GK-2	CAD/ CAD	09/05/46	09/05/46	2.850 %	2.898 %	300.0		300.0
GK-3	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.227 %	150.0		150.0
GK-4	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.526 %	300.0		300.0
GK-5	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.440 %	225.0		225.0
GK-6	CAD/ CAD	09/05/46	09/05/46	2.850 %	3.275 %	150.0		150.0
GR-3	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.310 %	300.0		300.0
GR-4	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.495 %	300.0		300.0
GR-5	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.190 %	300.0		300.0
GR-6	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.186 %	300.0		300.0
GR-7	CAD/ CAD	09/05/48	09/05/48	3.400 %	3.411 %	300.0		300.0
FN	CAD/ CAD	03/05/50	03/05/50	4.700 %	4.726 %	200.0		200.0
FN-2	CAD/ CAD	03/05/50	03/05/50	4.700 %	3.629 %	75.0		75.0
FN-3	CAD/ CAD	03/05/50	03/05/50	4.700 %	3.281 %	50.0		50.0
GV	CAD/ CAD	03/05/50	03/05/50	3.200 %	3.258 %	400.0		400.0
GV-2	CAD/ CAD	03/05/50	03/05/50	3.200 %	3.252 %	400.0		400.0
GV-3	CAD/ CAD	03/05/50	03/05/50	3.200 %	3.415 %	150.0		150.0
C129	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.178 %	50.0		50.0
C129-2	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.918 %	55.0		55.0
C129-3	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.065 %	50.0		50.0
C129-4	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.099 %	50.0		50.0
C129-5	CAD/ CAD	09/05/52	09/05/52	3.150 %	4.087 %	50.0		50.0
C129-6	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.906 %	50.0		50.0
C129-7	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.915 %	20.0		20.0
C129-8	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.895 %	20.0		20.0
C129-9	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.858 %	60.0		60.0
C129-10	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.786 %	50.0		50.0
C129-11	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.702 %	25.0		25.0
C129-12	CAD/ CAD	09/05/52	09/05/52	3.150 %	3.699 %	40.0		40.0
C139	CAD/ CAD	09/05/54	09/05/54	3.650 %	3.666 %	50.0		50.0
C139-2	CAD/ CAD	09/05/54	09/05/54	3.650 %	3.625 %	25.0		25.0
4Z	CAD/ CAD	06/09/57	06/09/57	7.100 %	7.100 %	7.0		7.0
C110	CAD/ CAD	03/05/60	03/05/60	5.200 %	4.629 %	125.0		125.0
C109	CAD/ CAD	03/05/63	03/05/63	4.625 %	4.638 %	50.0		50.0
C109-5	CAD/ CAD	03/05/63	03/05/63	4.625 %	3.597 %	50.0		50.0
C109-6	CAD/ CAD	03/05/63	03/05/63	4.625 %	3.555 %	50.0		50.0
C109-7	CAD/ CAD	03/05/63	03/05/63	4.625 %	3.506 %	50.0		50.0
C137-13	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.342 %	50.0		50.0
C137-16	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.163 %	150.0		150.0
C137	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.496 %	50.0		50.0
C137-2	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.887 %	25.0		25.0
C137-3	CAD/ CAD	03/05/63	03/05/63	3.450 %	4.019 %	37.0		37.0
C137-4	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.868 %	60.0		60.0
C137-5	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.354 %	50.0		50.0
C137-6	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.378 %	62.0		62.0
C137-7	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.502 %	75.0		75.0
C137-8	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.232 %	50.0		50.0
C137-9	CAD/ CAD	03/05/63	03/05/63	3.450 %	2.835 %	25.0		25.0
C137-10	CAD/ CAD	03/05/63	03/05/63	3.450 %	2.854 %	100.0		100.0
C137-11	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.457 %	100.0		100.0
C137-12	CAD/ CAD	03/05/63	03/05/63	3.450 %	3.404 %	100.0		100.0
C160-2	CAD/ CAD	03/05/68	03/05/68	3.100 %	3.061 %	150.0		150.0
C160-4	CAD/ CAD	03/05/68	03/05/68	3.100 %	3.150 %	25.0		25.0
Total Long Term Debt						**20,007.4**	**1,105.0**	**21,462.6**

c) The following table details the debt issuance and corresponding interest rates:

Year	Debt Issued in year (millions)	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate MH93 (12 yr rate)	Notional Interest in year (millions)
2016	$ 2,208.2	3.87%	5.68%		$ 85.5
2017	$ 2,162.8	3.48%	5.41%		$ 75.3
2018	$ 3,380.6	3.67%	5.10%	3.40%	$ 124.2
2019	$ 3,364.5	4.25%	4.85%	3.85%	$ 142.9
2020	$ 2,200.0	4.71%	4.79%	4.29%	$ 103.6
Total	$ 13,316.1				$ 531.4

Note 1: Debt Issued excludes refinancing of underlying debt linked to ongoing interest rate swaps

Note 2: All rates include 1% PGF

Note 3: 2019 represents actual debt issuance to December 31, 2018 and forecast debt issuance afterwards

The information requested for the period beyond the 2019/20 test year is not available at the current time. The assumptions underpinning the requested information will be considered in the context of the MHEB's approval of the Corporation's next Integrated Financial Forecast and provided in Manitoba Hydro's next full GRA.

d) This response assumes the requested comparison is to the updated table shown in part c) of this Information Request and not part e), as listed in the question. As noted in the response to part c), the information requested for the period beyond the 2019/20 test year is not available at the current time.

The table from PUB/MH I-32b from the 2017/18 & 2018/19 GRA showed only the forecast debt remaining to be issued for the fiscal year 2018. For completeness, the fiscal 2018 data from PUB/MH I-32b has been restated to include actual debt issuance in addition to the previously reported forecast debt issuance. The restated table is as follows:

Year	Debt Issued in year (millions)	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate MH93 (12 yr rate)	Notional Interest in year (millions)
2018	$ 3,433.4	3.17%	5.13%	3.40%	$ 108.8
2019	$ 3,600.0	3.85%	4.71%	3.85%	$ 138.6
2020	$ 2,200.0	4.29%	4.61%	4.29%	$ 94.4

A table showing the differences between the restated PUB-MH I-32b and part c) of this response is as follows:

Year	Debt Issued in year (millions)	WAIR of debt issued in year	WAIR of all outstanding debt at March 31	Forecast interest rate MH93 (12 yr rate)	Notional Interest in year (millions)
2018	$ (52.8)	0.50%	-0.03%		$ 15.4
2019	$ (235.5)	0.40%	0.14%		$ 4.3
2020	$ -	0.42%	0.18%		$ 9.2
Total	$ (288.3)				$ 28.9

Fiscal 2018: The volume of debt issued for the fiscal year was approximately $53 million lower than forecast in Exhibit MH93 and the weighted average interest rate (“WAIR”) was 0.50% higher. However, the WAIR on all outstanding debt at year end was relatively unchanged due to timing of the actual debt issuances. The notional interest on debt issued in the year was $15.4 million higher than forecast in Exhibit MH93.

Fiscal 2019: The Current Outlook forecasts that the volume of debt issuance will be $235.5 million less than the Exhibit MH93 forecast primarily due to lower capital expenditures. The WAIR is forecast to be higher by 0.40% mostly due to a change in terming strategy for new and actual debt issuance amending the actual and forecast weighted average term to maturity (“WATM”) from 12 years in Exhibit MH93 to 20 years in the Current Outlook. Subsequent to the filing of Exhibit MH93 and during the course of the 2017/18 & 2018/19 GRA, the Bank of Canada interest rates rose such that the cost advantage to borrowing shorter term maturities did not materialize. The yield curve continued to flatten such that there is now only a minimal difference between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of

Manitoba bond. Considering this interest rate environment, Manitoba Hydro reverted to a longer term borrowing strategy of targeting a 20 year WATM for new borrowings as opposed to the 12 year assumption in Exhibit MH93. These differences resulted in the forecast WAIR on all outstanding debt being 0.14% higher by yearend and a $4.3 million increase in notional interest on debt issued within the year.

Fiscal 2020: The Approved Budget forecasts that the volume of debt issuance will be equal to the Exhibit MH93. The WAIR is forecast to be higher by 0.42% mostly due to a change in terming strategy for new debt issuance amending the forecast weighted average term to maturity from 12 years in Exhibit MH93 to 20 years in the 2019/20 Approved Budget. These differences resulted in the forecast WAIR on all outstanding debt being 0.18% higher by yearend and a $9.2 million increase in notional interest on debt issued within the year.

e) The following table provides a schedule detailing the current refinancing plans, the weighted average term of outstanding debt, the principle amount and proportions of debt maturing in 10 years, 20 years and greater than 20 years as projected at the end of 2019/20.

MANITOBA HYDRO

PUB-MH I-38 e) - Finance Expense - Debt Levels

Actuals are shown for March 31, 2004 - December 31, 2018; with forecast information afterward to March 31, 2020.

($ in CAD millions)

	Debt Maturing Less than 10 Years		Debt Maturing Between 10 - 20 Years		Debt Maturing Greater than 20 Years		Total Long Term Debt	Weighted Average Term to Maturity
	$	% of Total	$	% of Total	$	% of Total	$	(Years)
March 31, 2004	2,586	35.1 %	3,521	47.7 %	1,268	17.2 %	7,375	13.8
March 31, 2005	2,377	33.1 %	3,346	46.5 %	1,468	20.4 %	7,191	13.8
March 31, 2006	2,397	33.5 %	3,317	46.3 %	1,443	20.2 %	7,158	13.7
March 31, 2007	2,623	36.3 %	3,094	42.9 %	1,501	20.8 %	7,218	12.9
March 31, 2008	2,996	39.5 %	2,513	33.1 %	2,081	27.4 %	7,590	13.5
March 31, 2009	3,763	45.8 %	2,026	24.7 %	2,421	29.5 %	8,209	13.6
March 31, 2010	3,963	46.0 %	1,805	21.0 %	2,846	33.0 %	8,614	14.8
March 31, 2011	3,967	45.6 %	2,241	25.7 %	2,496	28.7 %	8,704	15.3
March 31, 2012	4,841	51.4 %	1,619	17.2 %	2,962	31.4 %	9,422	14.9
March 31, 2013	5,179	51.7 %	1,499	15.0 %	3,332	33.3 %	10,010	14.8
March 31, 2014	5,160	46.9 %	1,500	13.6 %	4,349	39.5 %	11,009	16.2
March 31, 2015	5,264	41.4 %	1,370	10.8 %	6,084	47.8 %	12,717	17.8
March 31, 2016	6,096	41.7 %	1,441	9.9 %	7,071	48.4 %	14,607	18.1
March 31, 2017	7,270	44.1 %	1,641	9.9 %	7,582	46.0 %	16,492	17.5
March 31, 2018	8,716	45.3 %	2,091	10.9 %	8,432	43.8 %	19,239	17.2
March 31, 2019 *	8,781	41.8 %	2,381	11.3 %	9,432	44.9 %	20,994	17.8
March 31, 2020 *	8,634	37.0 %	5,640	24.2 %	9,063	38.8 %	23,336	17.0

* The forecasted debt percentages and weighted average terms to maturity will be affected by the simplifying modeling assumption of a 20 year term to maturity for all new debt issuance. Actual terms to maturity will vary from forecast.

REFERENCE:

Application Appendix 1 Projected Cash Balance

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states that it has increased its borrowings in advance of need and that has resulted in an increase in finance expense.
MH 93 forecasts cash balances at the end of 2019 of $530 million versus $488 million per MH 93 an increase of cash on hand of $42 million. Manitoba Hydro's financing activities for 2018/19 are now forecast to be $2,567 million versus $2,366 million in MH 93 an increase of $201 million.
Manitoba Hydro is now forecasting a cash balance of $604 million for 2019/20 versus $523 million forecast in MH93. Manitoba Hydro is forecasting financing activities of $1,749 million in its 2020 interim budget versus $1,861 million in MH93 a reduction in funds raised in financing activities of $112 million.
Finance expense for 2019/20 is now forecast to be $44 million higher than that forecast in MH93.

QUESTION:

a) Indicate the extent finance expense in 2018/19 is impacted by borrowings made in advance of need.
b) Identify the amount of interest expense that relates to borrowings made in advance of need. Provide the impact on net income that would result if this expense was capitalized in each of 2017/18, 2018/19, and 2019/20.

RESPONSE:

Response to parts a) & b)

In the current market context, Manitoba Hydro does not view the surplus cash balances to be held in advance of need; these surplus cash balances are required to protect against the potential costs of current market risks. With regard to the impact to finance expense, given the flat yield curve, there is not a significant cost to carry positive cash balances as the rate at which these funds are invested is only slightly lower than the rate at which the funds are borrowed. Furthermore, in an environment of rising interest rates, there is a positive long term impact to finance expense as new debt issuance is generally locked in at a lower rate than it otherwise would have been if issued later, closer to the planned cash requirement date. This interest rate risk protection provides benefit over the term of the debt issue (which is forecast to have a weighted average term to maturity of 20 years).

With the current and upcoming levels of debt financings the Corporation's liquidity risk remains elevated. Liquidity risk is the risk of not having sufficient funds, either internally generated funds or externally sourced debt financing to meet the Corporation's cash requirements. During the last few years, debt issuance has been characterized by periods of volatility and uneven market tone. Volatility is the tendency of a market to rise or fall sharply within a short period of time which can make investors nervous to participate in a new debt issuance. Positive market tone is characterized as having a high trading volume with rising prices, whereas any sort of instability or falling prices is seen as a negative market tone. These factors in the current market environment have escalated market liquidity risk by restricting at times, provincial access to external debt financing. The Corporation has the ability to issue up to $500 million of short term debt, however given the high level of current and near term cash requirements this offers a minimal level of liquidity protection. In order to maximize the availability of this credit facility for overdraft liquidity protection, the use of the short term debt program has been reduced in recent years.

Given these risks, the Corporation views a surplus cash balance as necessary to ensure that it can meet its cash obligations, including interest payments to the Province on advances received as well as payments to vendors, thus ensuring no disruptions to construction nor harm to its credit reputation due to liquidity issues. Should the Corporation have insufficient cash and a default occur when Manitoba Hydro is scheduled to make an interest or principal debt payment to bondholders through the Province, the harm to the Provincial credit reputation could impact the cost and availability of acquiring future financings. While the Province would take measures to ensure that such a default not occur, relying on the Province for assistance for payments to bondholders is a key indicator that a government business enterprise is not self-supporting. A default in any of the above payment situations would come with financial and reputational consequences which can be avoided with risk mitigation measures. To ensure smooth business continuity and financing flexibility while facing these challenges, Manitoba Hydro seeks to maintain unencumbered positive cash balances as part of its prudential liquidity practice. Taking into consideration the challenging market tone in recent years nearly all Provinces, including the Province of Manitoba, have maintained positive cash balances to protect against liquidity risk.

The Corporation will continue to monitor markets and upcoming cash requirements to determine the appropriate level of unencumbered cash required to protect against liquidity risk and adjust the balance accordingly.

REFERENCE:

2017/18 GRA MH68 pg. 64

PREAMBLE TO IR (IF ANY):

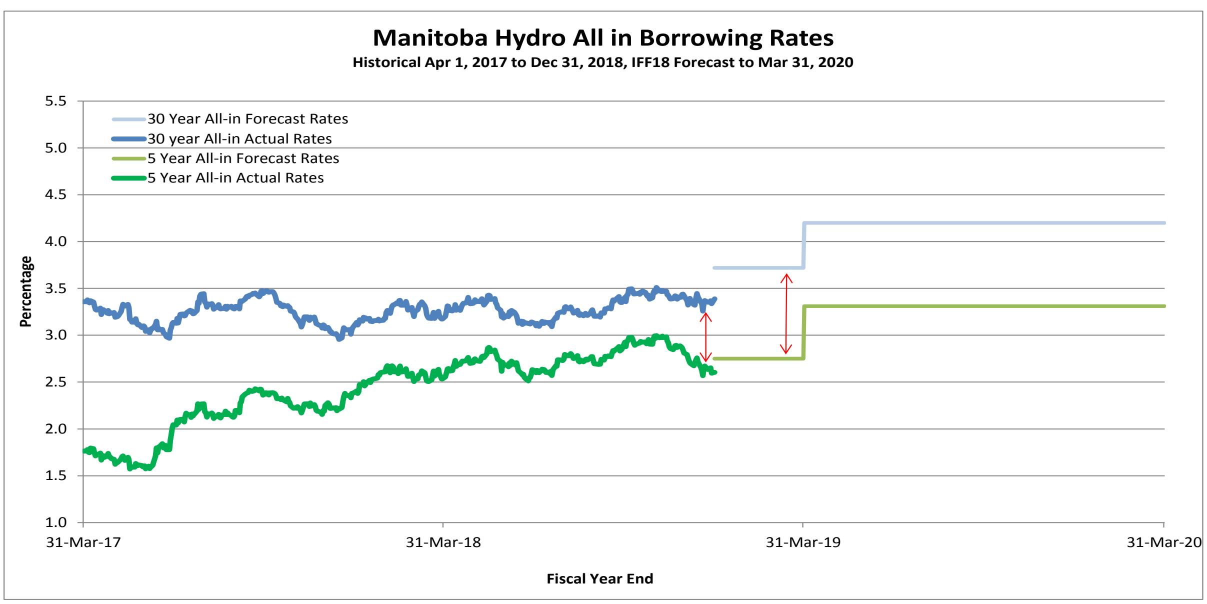
QUESTION:

a) File an update to the chart presented in MH68 slide 64 and related table of data points detailing the yields between the five year and 30 year Government of Canada bond rate. Please provide the chart through to the end of the test year.

b) Indicate the level of savings currently available for shorter term interest rates on 2018/19 and 2019/20 debt issuances.

RESPONSE:

a) The following chart is an update to the chart presented in Exhibit MH-68, slide 64, which showed the differential between the 5 and 30 year Province of Manitoba borrowing costs.



The following data points detail the Government of Canada yields, the Province of Manitoba credit spreads and the Province of Manitoba all-in borrowing costs from March 31, 2017 to the end of the test year. Actual data for April 1, 2017 to December 31, 2018 is based on the monthly average of the daily series.

(All Rates in %)	Government of Canada			Province of MB Spreads			Province of MB All-in Cost		
	30 year	5 year	Difference	30 year	5 year	Difference	30 year	5 year	Difference
April 2017	2.23	1.07	1.16	1.06	0.66	0.40	3.29	1.73	1.56
May 2017	2.16	1.01	1.15	1.03	0.63	0.41	3.20	1.64	1.56
June 2017	2.05	1.13	0.92	1.01	0.63	0.38	3.06	1.76	1.30
July 2017	2.28	1.55	0.73	0.98	0.60	0.38	3.26	2.15	1.11
August 2017	2.33	1.54	0.78	0.98	0.60	0.38	3.31	2.15	1.16
September 2017	2.42	1.75	0.67	0.99	0.61	0.38	3.40	2.36	1.05
October 2017	2.42	1.74	0.68	0.94	0.59	0.35	3.36	2.33	1.04
November 2017	2.27	1.66	0.61	0.88	0.56	0.32	3.15	2.22	0.93
December 2017	2.20	1.76	0.44	0.84	0.52	0.31	3.04	2.28	0.76
January 2018	2.36	2.02	0.34	0.80	0.49	0.31	3.16	2.51	0.65
February 2018	2.46	2.11	0.35	0.85	0.51	0.34	3.31	2.62	0.69
March 2018	2.34	2.03	0.31	0.90	0.53	0.37	3.24	2.56	0.68
April 2018	2.37	2.11	0.26	0.93	0.57	0.36	3.31	2.68	0.62
May 2018	2.42	2.23	0.19	0.92	0.54	0.38	3.34	2.77	0.58
June 2018	2.27	2.09	0.18	0.91	0.54	0.37	3.17	2.62	0.55
July 2018	2.23	2.12	0.12	0.93	0.53	0.39	3.16	2.65	0.51
August 2018	2.32	2.23	0.08	0.93	0.52	0.41	3.25	2.76	0.49
September 2018	2.36	2.26	0.10	0.94	0.52	0.42	3.30	2.78	0.52
October 2018	2.51	2.42	0.10	0.93	0.51	0.41	3.44	2.93	0.51
November 2018	2.47	2.36	0.11	0.97	0.56	0.41	3.44	2.91	0.52
December 2018	2.22	2.00	0.22	1.14	0.68	0.46	3.36	2.68	0.68
January 2019 to March 2019	2.81	2.21	0.60	0.91	0.54	0.37	3.72	2.75	0.97
April 2019 to March 2020	3.22	2.71	0.51	0.98	0.60	0.37	4.20	3.31	0.88

b) If Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Outlook and 2019/20 Interim Budget, would be approximately $7 million in fiscal 2019 and $17 million in fiscal 2020 on a cumulative basis. The yield curve has flattened considerably since the Winter 2017 interest rate forecast was prepared, and as a result the potential savings have diminished.

The flattening yield curve limits the potential savings available for long term debt with shorter terms to maturity. In addition, the availability of future surplus cash to retire maturing debt is uncertain as Manitoba Hydro reviews it's longer term financial plan. Without a longer term forecast of cash flow, issuing more debt with shorter terms to maturity could significantly increase the relative level of refinancing risk. Given the diminished potential savings and the cash flow uncertainty, the Corporation views it imprudent at this time to reduce the target weighted average term to maturity of new debt issuance for the sole purpose of short term interest savings and will continue to favour debt with longer terms to maturity for new debt issuances.

REFERENCE:

2017/18 GRA MH68 pg. 64

PREAMBLE TO IR (IF ANY):

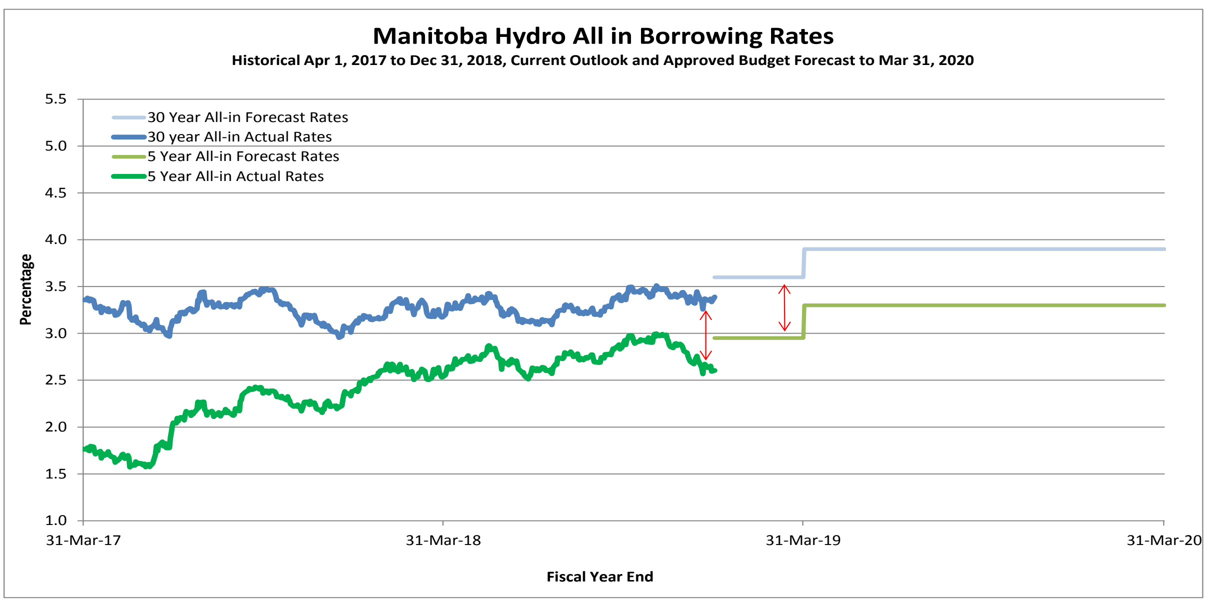
QUESTION:

a) File an update to the chart presented in MH68 slide 64 and related table of data points detailing the yields between the five year and 30 year Government of Canada bond rate. Please provide the chart through to the end of the test year.

b) Indicate the level of savings currently available for shorter term interest rates on 2018/19 and 2019/20 debt issuances.

RESPONSE:

a) The following chart is an update to the chart presented in Exhibit MH-68, slide 64, which showed the differential between the 5 and 30 year Province of Manitoba borrowing costs and is based on the Winter 2018 interest rate forecast.



The following data points detail the Government of Canada yields, the Province of Manitoba credit spreads and the Province of Manitoba all-in borrowing costs from March 31, 2017 to the end of the test year. Actual data for April 1, 2017 to December 31, 2018 is based on the monthly average of the daily series.

(All Rates in %)	Government of Canada			Province of MB Spreads			Province of MB All-in Cost		
	30 year	5 year	Difference	30 year	5 year	Difference	30 year	5 year	Difference
April 2017	2.23	1.07	1.16	1.06	0.66	0.40	3.29	1.73	1.56
May 2017	2.16	1.01	1.15	1.03	0.63	0.41	3.20	1.64	1.56
June 2017	2.05	1.13	0.92	1.01	0.63	0.38	3.06	1.76	1.30
July 2017	2.28	1.55	0.73	0.98	0.60	0.38	3.26	2.15	1.11
August 2017	2.33	1.54	0.78	0.98	0.60	0.38	3.31	2.15	1.16
September 2017	2.42	1.75	0.67	0.99	0.61	0.38	3.40	2.36	1.05
October 2017	2.42	1.74	0.68	0.94	0.59	0.35	3.36	2.33	1.04
November 2017	2.27	1.66	0.61	0.88	0.56	0.32	3.15	2.22	0.93
December 2017	2.20	1.76	0.44	0.84	0.52	0.31	3.04	2.28	0.76
January 2018	2.36	2.02	0.34	0.80	0.49	0.31	3.16	2.51	0.65
February 2018	2.46	2.11	0.35	0.85	0.51	0.34	3.31	2.62	0.69
March 2018	2.34	2.03	0.31	0.90	0.53	0.37	3.24	2.56	0.68
April 2018	2.37	2.11	0.26	0.93	0.57	0.36	3.31	2.68	0.62
May 2018	2.42	2.23	0.19	0.92	0.54	0.38	3.34	2.77	0.58
June 2018	2.27	2.09	0.18	0.91	0.54	0.37	3.17	2.62	0.55
July 2018	2.23	2.12	0.12	0.93	0.53	0.39	3.16	2.65	0.51
August 2018	2.32	2.23	0.08	0.93	0.52	0.41	3.25	2.76	0.49
September 2018	2.36	2.26	0.10	0.94	0.52	0.42	3.30	2.78	0.52
October 2018	2.51	2.42	0.10	0.93	0.51	0.41	3.44	2.93	0.51
November 2018	2.47	2.36	0.11	0.97	0.56	0.41	3.44	2.91	0.52
December 2018	2.22	2.00	0.22	1.14	0.68	0.46	3.36	2.68	0.68
January 2019 to March 2019	2.50	2.30	0.20	1.10	0.65	0.45	3.60	2.95	0.65
April 2019 to March 2020	2.90	2.70	0.20	1.00	0.60	0.40	3.90	3.30	0.60

b) In the response to PUB/MH I-40a-b based on the original application, the potential savings were calculated based on forecast debt issuance for the entirety of fiscal 2019 and 2020. Similarly, if Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances and existing debt issued in the Current Outlook year rather than a 20 year average, the level of savings available using the forecast rates incorporated in the 2018/19 Current Outlook and 2019/20 Approved Budget would be approximately $3 million in fiscal 2019 and $8 million in fiscal 2020 on a cumulative basis. The yield curve has flattened considerably since the Winter 2017 interest rate forecast was prepared, and as a result the potential savings have diminished.

If Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances beginning in January 2019 rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Current Outlook and 2019/20 Approved Budget, would be approximately $1 million in fiscal 2019 and $4 million in fiscal 2020 on a cumulative basis.

The flattening yield curve limits the potential savings available for long term debt with shorter terms to maturity. In addition, the availability of future surplus cash to retire maturing debt is uncertain as Manitoba Hydro reviews its longer term financial plan. Without a longer term forecast of cash flow, issuing more debt with shorter terms to maturity could significantly increase the relative level of refinancing risk. Given the diminished potential savings and the cash flow uncertainty, the Corporation views it imprudent at this time to reduce the target weighted average term to maturity of new debt issuance for the sole purpose of short term interest savings and will continue to favour debt with longer terms to maturity for new debt issuances.

REFERENCE:

Application pg. 3, 14

PREAMBLE TO IR (IF ANY):

QUESTION:

a) File a comparison of the detail of the Bipole III in-service additions forecast in MH 93 with that incurred for Bipole III.
b) Indicate to what extent bringing Bipole III in service 27 days early impacted the forecast for 2018 /19.

RESPONSE:

a) Please see the following table for a comparison of the projected March 31, 2019 cumulative Bipole III in-service amount as included in the response to Exhibit MH-93 from the 2017/18 & 2018/19 GRA (MH16 Update with Interim Forecast) and the actual cumulative Bipole III in-service balance as of December 31, 2018. The difference is primarily a result of lower overall expenditures as contingency funds to address unforeseen risks have not been required.

BIPOLE III IN-SERVICE ADDITIONS TO MARCH 31, 2019
(In millions of dollars)

	CEF16 * 31-Mar-19	Actual ** 31-Dec-18	Difference
Bipole III - Transmission Line	$ 1 947	$ 1 679	$ 268
Bipole III - Converter Stations	2 772	2 495	277
Bipole III - Collector Lines	247	220	26
Bipole III - Community Development Initiative	57	56	0
Bipole III Total	**$ 5 022**	**$ 4 451**	**$ 571**

* Consistent with the MH16 Update with Interim Forecast used in the 2017/18 and 2018/19 GRA
** Includes cumulative in-service additions to December 31, 2018

b) The financial impact of placing Bipole III in service 27 days earlier than planned results in additional net costs of $14.8 million for fiscal 2018/19, comprised of higher finance expense and higher depreciation expense partially offset by the amortization of Bipole III deferred revenue. The following table provides the breakdown of the $14.8 million reduction to net income.

	($ millions)
Finance expense	15.0
Depreciation	5.7
Amortization of deferred revenue	(5.9)
	14.8

REFERENCE:

Application p. 3

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide details of the U.S. transmission outages that led to reduced export volumes and a greater proportion of sales in the off-peak periods:

a) What was the net income impact of the outages?
b) When were the outages?
c) What was the decrease in volumes attributed to the outages?
d) Were these outages on Manitoba Hydro's transmission lines to the U.S. or lines situated in the U.S.?
e) Were the outages planned or unplanned?
f) What were the reasons for the outages?
g) Are these outages expected to be repeated in 2018/19 or 2019/20?
h) Why were sales shifted to the off-peak hours?

RESPONSE:

a) Manitoba Hydro has not completed a detailed assessment of the net income impact of all the outages. However it is estimated that during the summer period alone, the cost of lost export sales was $25-$30 million, as loss of U.S. market access limited generation on the Nelson River and resulted in spillage and inefficient operation.

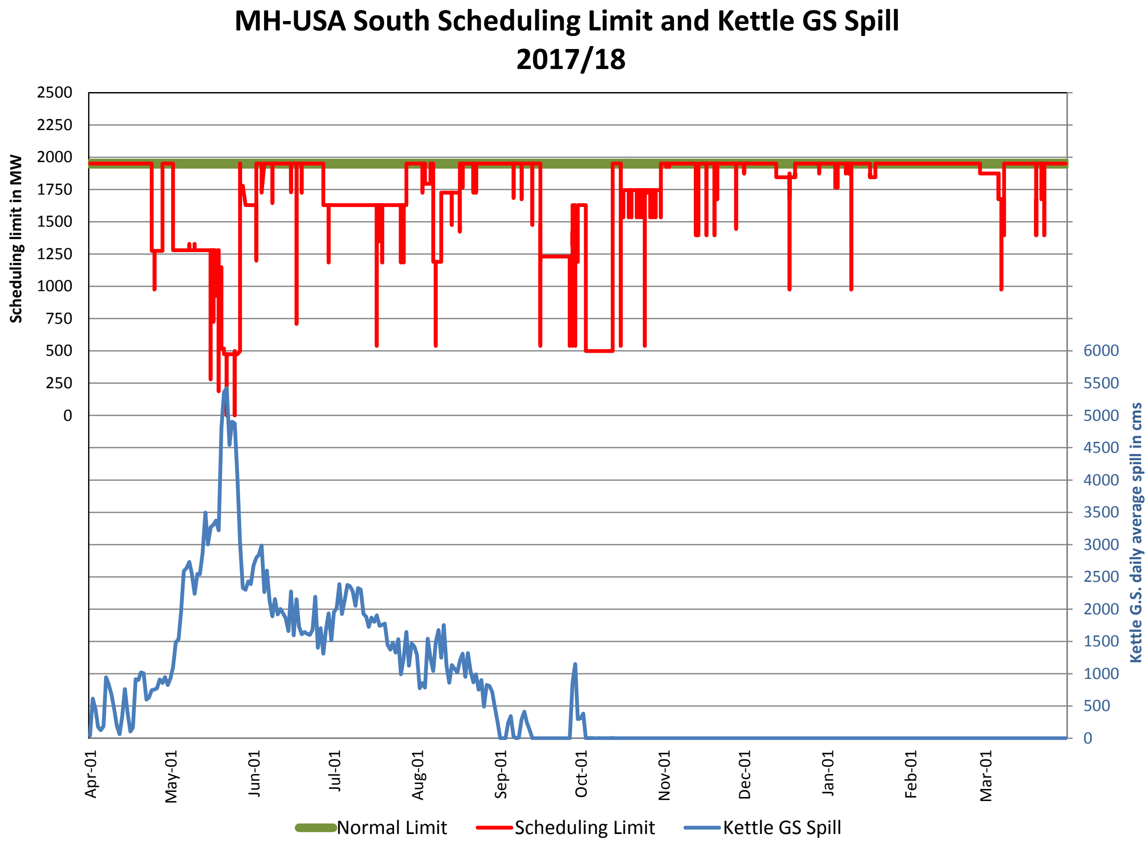
   A detailed net income assessment is quite complex and would be of limited value because it would require a number of important assumptions about what operations would have been in absence of these transmission outages. For example, the export price in the off peak at Manitoba Hydro's MISO Locational Marginal Price ("LMP") node can be affected by the volume of energy Manitoba Hydro is exporting. In addition, generation outages were scheduled during periods when Manitoba Hydro had limited market access to avoid incurring lost opportunity costs due to reduced generation at other times; alternative generator outage schedules in the absence of the interconnection outage are not available. In addition Manitoba Hydro's reservoir operations were modified as a result of the interconnection outages and Manitoba Hydro does not have alternative operations plans to compare to for the requested analysis.

b) Please refer to Figure 1 below for a detailed schedule of the outages. These outages restricted Manitoba Hydro access to the U.S. market for approximately 40% of the hours in 2017/18.

The following lists the major outages and reasons:

i. May 2-25, a 670 MW reduction due to the installation of a new 500 kV shunt reactor at Chisago Station in Minnesota,
ii. May 20-28, a 1430 MW reduction for Bipole III, crossing of the 500 kV line,
iii. Jun 26 - Jul 28, a 320 MW reduction due to an outage at Forbes station in Minnesota to investigate HVDC reduction problems,
iv. Sep 18-29, a 525 MW reduction due to work by SaskPower on Boundary Dam Transformer 922T,
v. Oct 3-13, a 1450 MW reduction due to Bipole III, related work which affected the 500 kV line and insulator change-outs at Forbes station in Minnesota,
vi. Oct 16-31, a 415 MW reduction due to Bipole III, which required sectionalizing line R49R while the Prairie Center line was out of service in Minnesota, and
vii. Nov 13-22, a 555 MW reduction due to a U.S. forced outage of the Balta Ramsey line while the Pickert to Grand Forks line was out of service.

Figure 1.



c) Manitoba Hydro has not prepared a detailed estimate of the volume of reduced exports attributable to these transmission outages. As indicated in the answer to part (a) this is a complex assessment. However it is estimated that approximately 1,000,000 MWh of energy sales would have been affected.

d) As indicated in part (b) some of the reductions involved Manitoba Hydro transmission facilities and some were due to outages in Saskatchewan and in the U.S.. Approximately 60% of U.S. transfer capability reduction occurrences were not related to outages in Manitoba.

e) A large proportion of these outages were planned in advance however as indicated in part (b) some were the result of forced outages.

f) Please see the response to part (b) for a sampling of reasons for the outages. In general some were required to accommodate Bipole III, construction, some were the result of upgrades and maintenance to the grid, some were the result of investigations into the grid protection systems and some were the result of forced outages.

g) Outages to the U.S. interconnection occur annually and to the extent Manitoba Hydro knows about them in advance, Manitoba Hydro includes their impacts in the Integrated Financial Forecast. It should be noted that 2017/18 was unusual given the impact of Bipole III related work. Once the second 500 kV U.S. interconnection enters service in 2020, the impact of transmission outages on exports and export revenues will be significantly less. This is one of the significant benefits of the new line. Manitoba Hydro works with MISO and its neighbouring transmission owners in planning and outage coordination activities in order to minimize reliability impacts and outage costs.

Manitoba Hydro cannot predict if these forced outages will be repeated in the future. Manitoba Hydro expects there will be transmission outages in 2018/19 and 2019/20 related to planned work and forced outage events in neighboring markets and Manitoba.

h) To the extent that outages reduce export capability, affected on-peak energy sales would normally be transferred to the offpeak hours reducing the financial impact of the outage. This was typical of the impact of outages after mid-September. However because 2017/18 was a high water year, the U.S. interconnection was already fully loaded in the off-peak hours and there was no room to mitigate the lost on-peak sales by increasing off-peak sales.

REFERENCE:

Application p. 23; 2017/18 GRA Appendix 3.1 IFF16 p. 16

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has not projected incremental export revenues associated with surplus dependable capacity.

QUESTION:

Confirm whether Manitoba Hydro has sold any firm capacity for 2018/19 or 2019/20 that is not identified in the chart in IFF16 page 16. If confirmed, provide the names of the counterparty to the sales, the amounts of capacity sold (MW and capacity factor), the periods of time over which the sales are to take place, and the expected revenues for each year.

RESPONSE:

Yes, Manitoba Hydro has sold firm capacity for 2018/19 or 2019/20 that is not identified in the chart in IFF16 page 16 as follows;

Contract	Start Date		End Date	[redacted]	
Minnesota Municipal Power Agency 5 MW UCAP Sale	June 2018	to	May 2019		3a
Minnesota Municipal Power Agency 70 MW UCAP Sale	June 2019	to	May 2020		

REFERENCE:

Application p. 26, 27; 2017/18 GRA MH-68 p. 33

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Confirm whether the methodology to determine the long-term energy price forecast remains the same as the methodology that underpinned MH16 Update with Interim and depicted in MH-68 page 33 from the 2017/18 GRA. If not confirmed, explain the changes.
b) Confirm whether the methodology to determine the high and low electricity export price forecasts remains the same as was reviewed by Daymark at the 2017/18 GRA and whether the same Energy Information Administration scenarios were selected for the high and low cases. If not confirmed, explain the changes to the methodology and why the changes were made.

RESPONSE:

a) Confirmed. The methodology to determine the long-term energy price forecast remains the same as the methodology that underpinned the MH16 Update with Interim forecast.

b) Confirmed. The methodology to determine the high and low electricity price forecasts remains the same as was reviewed by Daymark at the 2017/18 GRA and the same Energy Information Administration scenarios were selected for the high and low cases.

REFERENCE:

2017/18 GRA Tab 3 Fig 3.6 and 3.7; MH-68

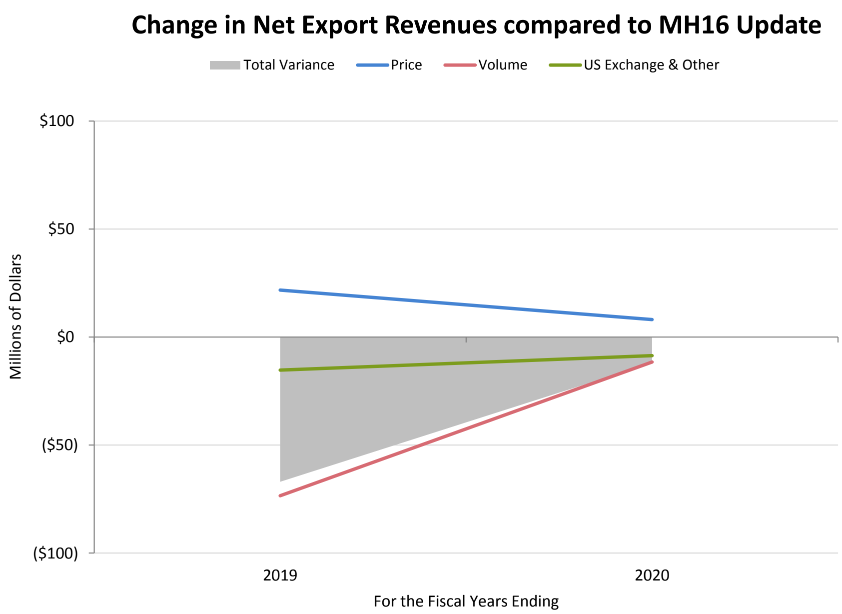
PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide an update to Figure 3.6 from Tab 3 of the 2017/18 GRA showing the change in forecast net export revenues between MH16 Update and the current forecast.
b) Provide an update to Figure 3.7 from Tab 3 of the 2017/18 GRA to include the current forecast, showing the progression of forecast average unit revenues compared to actual average prices, with the IFF16 low line removed from the Figure.
c) Provide an update to the graph of MISO market prices shown on MH-68 page 28 from the 2017/18 GRA.

RESPONSE:

a) An update to Figure 3.6 from Tab 3 of the 2017/18 GRA showing the change in forecasted net export revenues between MH16 Update and the 2018/19 Outlook and 2019/20 Interim Budget has been provided below.

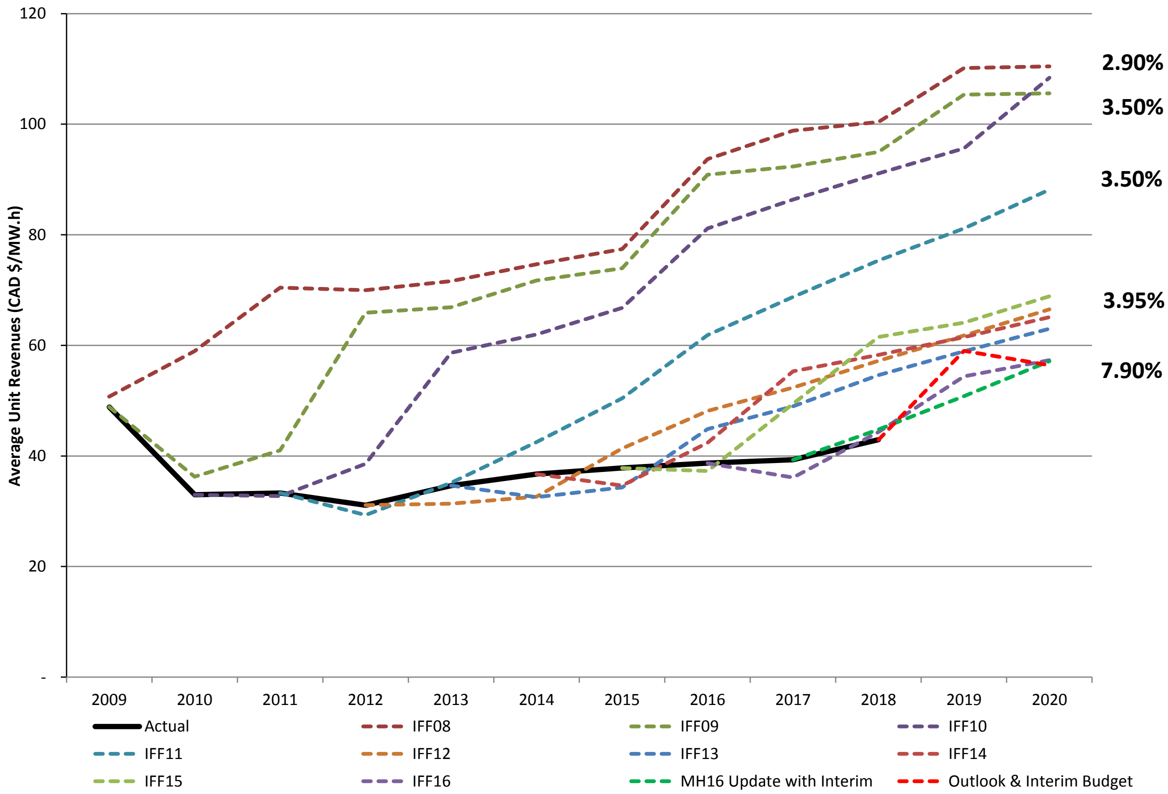


The 2018/19 Outlook for Net Export Revenues is $67 million lower compared to MH16 Update due mainly to lower hydraulic generation and import costs associated with lower actual and expected water flow conditions assumed in the 2018/19 Outlook compared with the average net export revenues under all historic flow conditions assumed in MH16 Update. A stronger actual and forecast Canadian dollar on average over 2018/19 also contributes to the lower net export revenues in the 2018/19 Outlook as compared to MH16 Update. In addition there are higher thermal costs as a result of the write-off of the coal inventory for the Brandon Thermal Station as the station has been converted to a synchronous condenser and is no longer operational as a coal powered generator. These reductions in net export revenues in the 2018/19 Outlook are partially offset by higher actual and forecast opportunity prices on average over 2018/19 compared to the forecast prices underpinning MH16 Update.

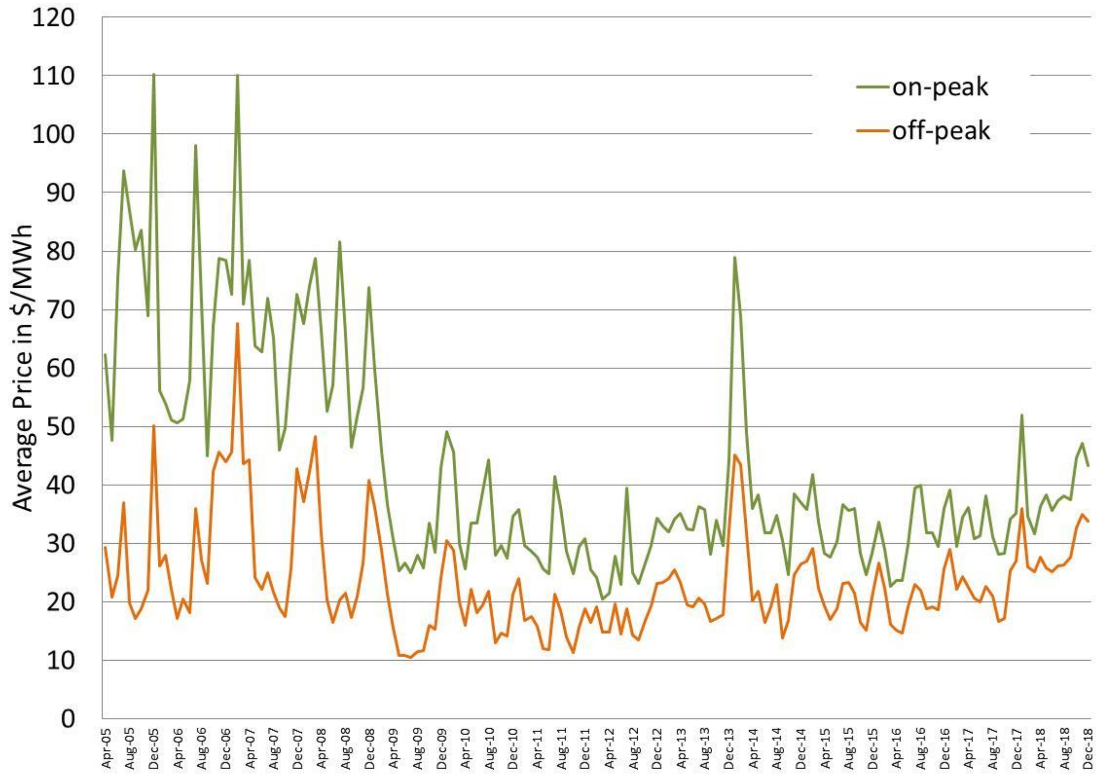
The 2019/20 Interim Budget is projected to be $12 million lower than MH16 Update due to lower opportunity sales and higher import costs as a result of a higher domestic load forecast, net of DSM savings, and a stronger forecasted Canadian dollar.

b) An update to Figure 3.7 from Tab 3 of the 2017/18 GRA has been provided below.

Progression of Forecast Average Unit Revenues Compared to Actual Average Prices



c) The graph of MISO market prices shown on page 28 of MH-68 from the 2017/18 GRA has been updated to December 2018 and is provided below.



REFERENCE:

2017/18 GRA Tab 3 Fig 3.6 and 3.7; MH-68

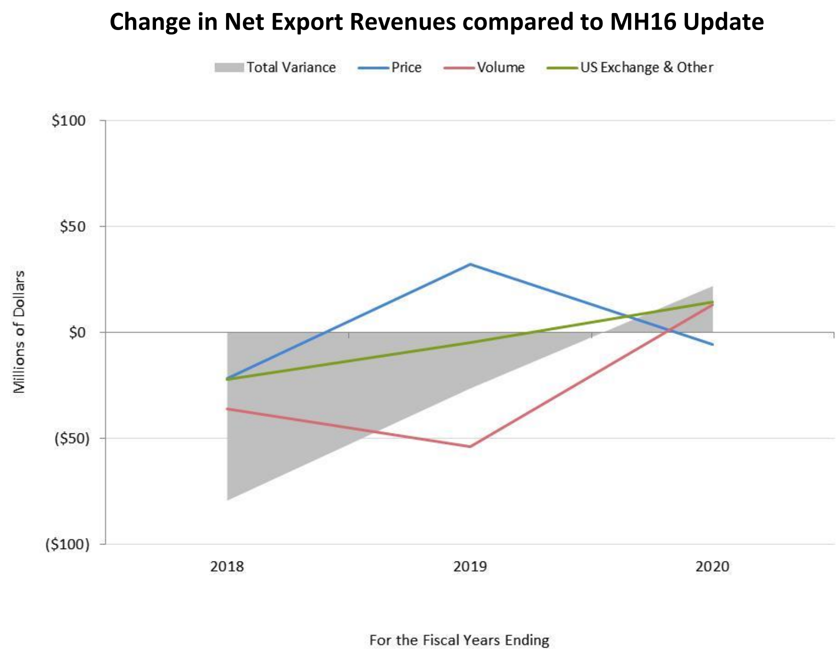
PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide an update to Figure 3.6 from Tab 3 of the 2017/18 GRA showing the change in forecast net export revenues between MH16 Update and the current forecast.
b) Provide an update to Figure 3.7 from Tab 3 of the 2017/18 GRA to include the current forecast, showing the progression of forecast average unit revenues compared to actual average prices, with the IFF16 low line removed from the Figure.
c) Provide an update to the graph of MISO market prices shown on MH-68 page 28 from the 2017/18 GRA.

RESPONSE:

a) An update to the response to PUB/MH-I-45a has been provided below. The graph and supporting data has been updated to include the variance analysis between 2017/18 Actual results, 2018/19 Current Outlook, 2019/20 Approved Budget and MH16 Update.



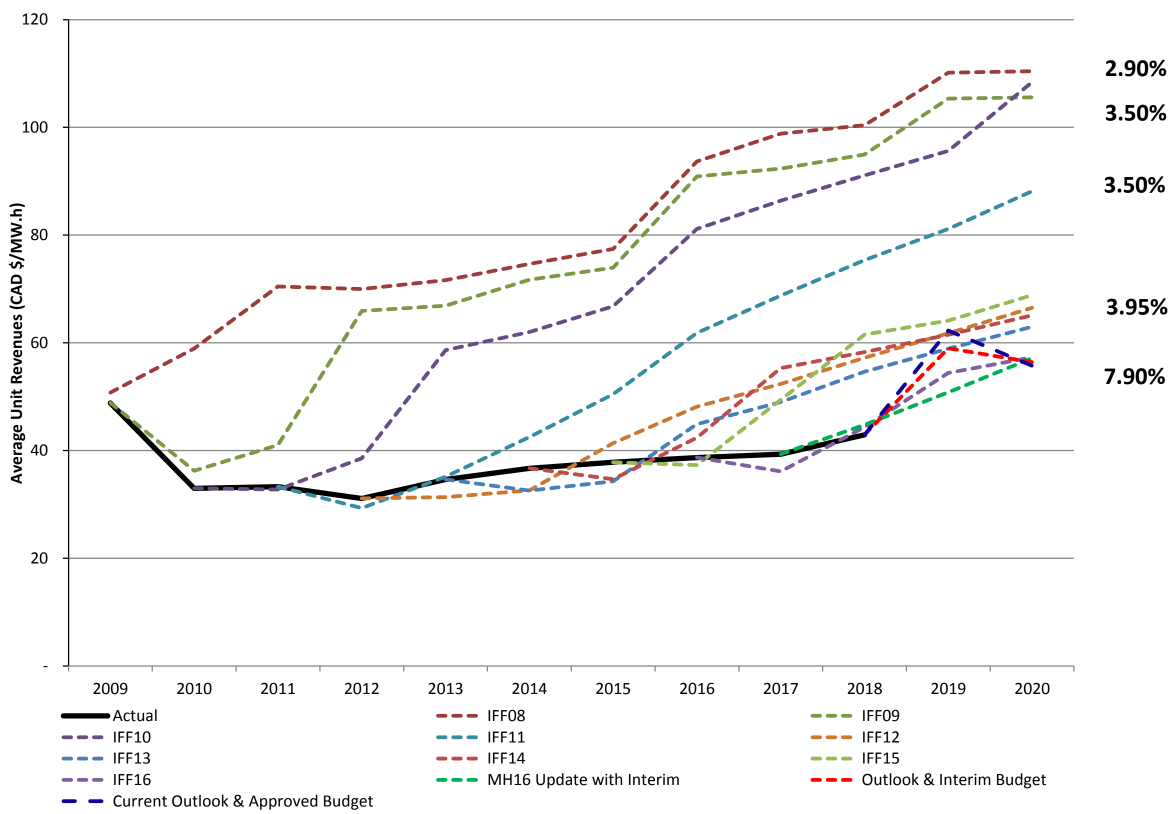
Price Volume Variance	2018	2019	2020
Price Variance	(22)	32	(5)
Volume Variance	(36)	(54)	13
Other Variance	(4)	(2)	12
FX Variance	(18)	(2)	3
Total	**(79)**	**(26)**	**22**

The 2017/18 Actual net export revenues were $79M lower than those forecasted in MH16 Update. This is primarily due to lower average unit revenues, lower than expected water flow conditions assumed in MH16 Update as well as a stronger Canadian dollar.

The 2018/19 Current Outlook net export revenues are $26M lower than those forecasted in MH16 Update. This is due mainly due to lower actual and expected water flow conditions compared with the average net export revenues under all historic water flow conditions assumed in MH16 Update. These lower water flow conditions were offset by an increase in price variance due to less volumes being exported at the lower off-peak prices and more in the higher priced on-peak market. As well, Manitoba Hydro experienced stronger opportunity prices in the first half of 2018/19, particularly in the Canadian market.

The 2019/20 Approved Budget net export revenues are $22M higher than those forecasted in MH16 Update. This is primarily due to a $13M volume variance attributable to lower thermal burn as well a $12M variance due to 'Other'. The $12M in 'Other' is attributable to lower transmission charges primarily due to Manitoba Hydro optimizing its firm transmission service portfolio by redirecting some of its firm transmission service to lower cost nodes as well as lower carbon taxes due to the reduction in thermal burn assumptions.

b) The graph provided in the response to PUB/MH I-45b has been updated based on the 2018/19 Current Outlook and the 2019/20 Approved Budget and is provided below.



c) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

Application pg. 3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Quantify the increases in net export revenues for 2018/19 and 2019/20 resulting from the decreased line losses of Bipole III entering service. Are these increases based on dependable energy conditions, average water flows, or some other hydrological condition?

RESPONSE:

These increases in net export revenues are based on the average of all flow conditions. The estimated reduction in HVDC losses attributed to Bipole III for a full year is 324 GWh (as shown in Figure 7.6 on page 14 of Tab 7 of Manitoba Hydro's 2017/18 & 2018/19 General Rate Application). The estimated increase in net export revenues from the reduction in losses is as follows:

	2018/19	2019/20	
a. Bipole III reduction in losses in GWh (at generation)[1]	240	324	
b. Bipole III reduction in losses in GWh (at border) (b = a * 0.9)	216	292	
c. Average unit revenue for opportunity sales to US in $/MWh (December 11, 2018 Additional Information, Attachment 3).	[redacted]	[redacted]	5c
d. Estimated increase in net export revenue in $millions (d = b × c)	[redacted]	[redacted]	5c

[1] Prorated for 2018/19 based on July 4, 2018 in-service date.

REFERENCE:

Application pg. 3

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Confirm whether the increased export revenues resulting from Bipole III entering service are reflected in the 2018/19 Outlook and 2019/20 Interim Budget forecasts. Has the 2018/19 forecast of net export revenues been revised to reflect the July 4, 2018 in service date?

RESPONSE:

The 2018/19 Outlook includes actuals through the first six months ending September 30, 2018 and therefore inherently incorporates the increase in net export revenue due to a reduction in HVDC losses for this period. The remainder of the 2018/19 Outlook period does not directly account for reduced transmission losses attributed to Bipole III.

The reduction in HVDC losses attributed to Bipole III is incorporated into the 2019/20 Interim Budget.

REFERENCE:

Application pg. 3

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Confirm whether the increased export revenues resulting from Bipole III entering service are reflected in the 2018/19 Outlook and 2019/20 Interim Budget forecasts. Has the 2018/19 forecast of net export revenues been revised to reflect the July 4, 2018 in service date?

RESPONSE:

Net export revenues in the 2018/19 Current Outlook and the 2019/20 Approved Budget prepared in January 2019 account for the reduction in HVDC losses attributed to Bipole III, which came into service on July 4, 2018.

REFERENCE:

Application pg. 23, 27; Fall 2017 Energy Price Forecast; PUB MFR 79 and DEA-1 pg. 44, 45 (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide the Fall 2017 Energy Price Forecast in a similar format to PUB MFR 79 from the 2017/18 GRA.
b) Provide graphs of the on-peak prices, off-peak prices, and capacity prices showing the independent forecasts and Manitoba Hydro's consensus reference prices in a similar format to that on pages 44 and 45 of Daymark's Export Pricing and Revenues Review from the 2017/18 GRA. Also show the consensus reference prices from the Spring 2017 Energy Price Forecast (PUB MFR 79) on these graphs.
c) Provide graphs of the on-peak prices, off-peak prices, and capacity prices showing Manitoba Hydro's consensus reference prices as well as the high and low cases that Manitoba Hydro bases on Energy Information Administration scenarios.

RESPONSE:

Response to Parts a) through c):
The 2019/20 Interim Budget reflects Manitoba Hydro's reference case electricity export price forecast (Fall 2017 Energy Price Forecast) derived from a number of independent price forecasts for the MISO region. The independent price forecast consultants provide a forecast for MISO's Minnesota Hub (MINN HUB), which is an aggregation of generation and load pricing nodes in the Minneapolis area.

Manitoba Hydro is under a contractual obligation to treat the forecasts as confidential but has obtained the consent of the forecasters to provide the forecasts to the PUB, which consent was granted provided that they be held in confidence by the PUB.

The independent price forecasts are used to create Manitoba Hydro's consensus forecast. The Manitoba Hydro consensus forecast is used for financial modeling purposes and forms the basis for negotiation of Manitoba Hydro's long term export contracts. The Manitoba Hydro consensus forecast is confidential to Manitoba Hydro as is the identity and forecasts of the price forecasters used in the consensus forecast. Knowledge of the Corporation's views regarding the future price of power will harm Manitoba Hydro's competitive position and negatively impact export power sale negotiations as parties will not want to pay more than the forecast values if those are known to counterparties. Input forecasts typically provide divergent future views hence the identities of the forecasters must be protected to avoid facilitating counterparties recreating Manitoba Hydro's consensus forecast.

The three tables below contain the reference case export price forecasts which underpin the 2019/20 Interim Budget and compares to the export price forecasts which underpin MH16 Update from the 2017/18 GRA.

[redacted] 2 + 3

The following figures provide a comparison between the spring and fall 2017 export prices forecasts for the 2019/20 Interim Budget:

[redacted] 2 + 3

It should be noted that MH delivers its power at the border between Manitoba and the U.S. represented by a pricing node called MHEB or Manitoba interface. MH calculates an adjustment and applies it to account for the historical transmission congestion and marginal transmission line losses between the MINN and MHEB pricing nodes. [redacted] 2a

There is inherent uncertainty in the reference case export price forecast, and particular uncertainty as to how future legislative and regulatory requirements may evolve. As such, Manitoba Hydro has developed high and low electricity export price forecasts as sensitivities around the reference case using information prepared by the U.S. Energy Information Administration (EIA). The table below compares the high and low forecasts to the reference case forecast.

[redacted]

[redacted] 2 + 3

The same congestion differentials noted above are applied to the low and high price sensitivities to derive the forecast price at the MHEB node.

REFERENCE:

Application pg. 21; December 11, 2018 Additional Information pg. 4 of 6

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the estimated impact to the load forecast volumes, net export revenue, and net income if the load forecast was adjusted to remove the elasticity effects of a 7.9% rate increase April 1, 2018 and substituted with the approved average 3.6% rate increase effective June 1, 2018.

RESPONSE:

The estimated impact to the load forecast volumes in 2019/20 is an additional 43 GWh of load at meter. The increase of load at meter will increase the domestic revenues by approximately $3 million and reduce net export revenues by approximately $1.5 million. The impact will result in an increase of net income by approximately $1.5 million.

REFERENCE:

2016/17 Power Smart Plan 15 Year Supplement; 2017/18 GRA PUB/MH II-57 and MH-115; 2017/18 GRA Appendix 7.2 p. (iv)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Manitoba Hydro confirmed that the new marginal values shown in 2017/18 GRA PUB/MH II 57 and exhibit MH-115 were not incorporated into the cost effectiveness tests used to develop the 2018/19 DSM plan. Confirm whether the marginal values shown in 2017/18 GRA PUB/MH II 57 and exhibit MH-115 will be incorporated into the cost effectiveness tests used to develop the 2019/20 DSM plan as recommended in Order 59/18 Recommendation 9. If not confirmed, explain what other marginal values will be used and why.

b) Identify the DSM programs shown in the figure on page (iv) of the 2016/17 Power Smart Plan 15 Year Supplement that are no longer economic according to the updated levelized utility cost shown in PUB/MH II-57 and which are included in the 2018/19 DSM Plan.

RESPONSE:

a) The marginal values shown in PUB/MH II-57 of the 2017/18 & 2018/19 GRA and exhibit MH-115 will not be used in the development the 2019/20 DSM plan. The 2019/20 DSM Plan is being prepared in consultation with the Province of Manitoba in accordance with *The Energy Savings Act*. As directed by the Province, the 2019/20 1-year plan, which will be used for the 2019/20 fiscal year, represents a status quo approach and continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba.

b) Given that the Province has directed a status quo approach and continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba, Manitoba Hydro has not undertaken any cost effectiveness assessments of its 2016/17 Power Smart Plan 15 Year Supplement.

REFERENCE:

Application p. 21; 2018/19 DSM Plan p. 2; 2017/18 GRA PUB MFR 61 (2017/18 DSM Plan) p.2; 2017/18 GRA Appendix 7.2 2016/17 Power Smart Plan 15 Year Supplement p. 85 and 86 of 128

PREAMBLE TO IR (IF ANY):

On page 21 of the Application, Manitoba Hydro states:

The future program based DSM savings incorporated in the 2019/20 Interim Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for actual DSM savings achieved in 2017/18 and the carry-forward effects of the changes made to the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government.

Compared to the 2017/18 DSM Plan, the 2018/19 DSM Plan forecasts an additional 49.8 GWh of energy savings due to the Load Displacement Program and a decrease in energy savings of 17.8 GWh in the BioEnergy Optimization Program, for a net increase in savings of 32 GWh (at generation).

QUESTION:

a) Provide a breakdown of the 99 GWh increase in DSM savings over MH-93 identified on page 21 of the Application by DSM program. For the programs that are the greatest contributors (positive or negative) to the 99 GWh savings, explain the reasons for the change (i.e. program design change, customer uptake greater or less than previously anticipated, etc.).
b) Provide a table or tables that identify the changes in demand and energy savings between the 2016/17 Power Smart Plan 15 Year Supplement Appendix A.1 and A.2 and the 2019/20 Interim Budget assumptions for the 2019/20 test year, broken down by program. Explain any material differences.
c) Identify whether Manitoba Hydro has added or deleted any DSM programs from its portfolio of programs listed in the 2018/19 DSM Plan at page 2, or whether substantive changes have been made to these programs.

d) Explain the reasons for the decrease in the forecast of DSM savings for the BioEnergy Optimization Program and the increase in the DSM savings for the Load Displacement Program when comparing the 2018/19 DSM Plan to the 2017/18 DSM Plan. Have the Load Displacement Program savings expected in the 2018/19 DSM Plan been affected by the delayed implementation of customer-sited self-generation identified on page 21 of the Application?

RESPONSE:

The future program based DSM savings incorporated in the 2019/20 Interim Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for the carry-forward effects of the changes made to the 2017/18 one-year DSM plan and the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government.

a) The following table provides a breakdown of the 99 GW.h decrease (not “increase” as noted in the question) in DSM savings in the 2019/20 Interim Budget over Exhibit MH-93.

The programs that are the greatest contributors to the difference are:

- Customer Sited Load Displacement - The 27.8 GW.h decrease reflects a delay in projects expected to be completed in 2018/19 to future years.
- Conservation Rates – Residential - The 25.8 GW.h decrease reflects the removal of those 2018/19 forecast savings attributable to new programs which were planned to be introduced by Manitoba Hydro but have been suspended pending transition of responsibility for DSM programming and services to Efficiency Manitoba following consultation with the Province pursuant to *The Energy Savings Act*.
- Fuel Choice - The 51.1 GW.h decrease reflects the removal of those 2018/19 forecast savings attributable to new programs which were planned to be introduced by Manitoba Hydro but have been suspended pending transition of responsibility for DSM programming and services to Efficiency Manitoba following consultation with the Province pursuant to *The Energy Savings Act*.

Table: Comparison of Forecast DSM Savings by Program

		2019/20 Interim Budget	Exhibit 93	Change
RESIDENTIAL		2019	2019	2019
Incentive Based				
	New Homes Program	4.5	2.7	1.8
	Home Insulation Program	8.8	8.7	0.1
	Affordable Energy Program	8.7	7.8	1.0
	Water and Energy Saver Program	5.2	6.8	-1.6
	Refrigerator Retirement Program	20.8	22.1	-1.3
	Drain Water Heat Recovery Initiative	0.0	0.0	0.0
	Residential LED Lighting Program	30.1	21.1	8.9
	Community Geothermal Program	7.2	8.8	-1.6
	Appliances	1.6	0.5	1.1
	HRV Controls	0.3	1.5	-1.2
	Power Bars	0.0	0.0	0.0
	Smart Thermostats	0.8	0.4	0.4
	Plug-in Timers	0.4	0.1	0.2
	Community Energy Plan	0.0	0.0	0.0
		88.4	80.5	7.9
Customer Service Initiatives / Financial Loan Programs				
	Power Smart Residential Loan	0.8	0.9	-0.1
	Power Smart PAYS Financing	0.4	0.5	-0.1
	Residential Earth Power Loan	1.5	1.2	0.3
		2.7	2.6	0.0
COMMERCIAL				
Incentive Based				
	Commercial Lighting Program	138.9	132.1	6.8
	LED Roadway Lighting Conversion Program	35.0	33.3	1.7
	Commercial Building Envelope - Windows Program	2.8	3.0	-0.2
	Commercial Building Envelope - Insulation Program	7.8	6.7	1.0
	Commercial Geothermal Program	2.6	3.4	-0.8
	Commercial HVAC Program - Chillers (Water-Cooled)	1.0	1.0	0.0
	Commercial HVAC Program - CO2 Sensors	1.0	1.6	-0.6
	Commercial HVAC Program - HRVs	1.6	2.3	-0.7
	Commercial HVAC Program - Air Cooled Chillers	1.3	2.5	-1.2
	Commercial Custom Measures Program	5.2	5.1	0.1
	Commercial Building Optimization Program	2.4	2.3	0.1
	New Buildings Program	12.0	12.0	0.0
	Commercial Refrigeration Program	20.3	20.1	0.2
	Commercial Kitchen Appliance Program	0.3	0.2	0.1
	Network Energy Management Program	0.2	0.4	-0.1
	Internal Retrofit Program	0.0	0.0	0.0
	Power Smart Shops	5.1	5.8	-0.7
	Power Smart Energy Manager	0.9	1.4	-0.5
	Race to Reduce	5.8	6.5	-0.7
	Parking Lot Controller	1.6	0.7	0.9
		245.8	240.4	5.4
Customer Service Initiatives / Financial Loan Programs				
	Power Smart for Business PAYS Financing	0.0	0.0	0.0
		0.0	0.0	0.0
INDUSTRIAL				
	Performance Optimization Program	45.6	53.8	-8.2
		45.6	53.8	-8.2
LOAD DISPLACEMENT & ALTERNATIVE ENERGY				
	Bioenergy Optimization Program	24.0	31.0	-7.0
	Customer Sited Load Displacement	259.2	286.9	-27.8
		283.2	318.0	-34.8
CONSERVATION RATES				
	Conservation Rates - Residential	64.4	90.2	-25.8
	Conservation Rates - Commercial	43.2	43.2	0.0
		107.6	133.4	-25.8
FUEL CHOICE				
	Fuel Choice	51.1	102.2	-51.1
		51.1	102.2	-51.1
OTHER EMERGING TECHNOLOGIES				
	Residential Solar Photovoltaics Program (PV)	6.9	0.5	6.5
	Residential Solar Thermal Program - Water Heating	0.0	0.1	0.0
	Residential Solar Thermal Program - Pool Heating	0.1	0.1	-0.1
	Commercial Solar Photovoltaics Program (PV)	2.3	0.5	1.8
	Commercial Variable Speed and Frequency Drives	0.5	1.0	-0.5
		9.8	2.1	7.6
	Planned DSM Savings (at meter)	**834**	**933**	**-99**

b) Forecast savings for the 2019/20 year incorporated in the 2019/20 Interim Budget were sourced from the 2016/17 Power Smart Plan 15 Year Supplement Appendix A.1 and A.2. The table below shows the incremental MW and GW.h for the 2019/20 year that is included in both forecasts.

		MW	GWh
RESIDENTIAL		2019	2019
Incentive Based			
	New Homes Program	0.3	1.0
	Home Insulation Program	1.3	2.6
	Affordable Energy Program	1.0	2.4
	Refrigerator Retirement Program	0.6	6.2
	Residential LED Lighting Program	1.5	4.7
	Community Geothermal Program	1.8	3.6
		6.5	20.4
Customer Service Initiatives / Financial Loan Programs			
	Power Smart Residential Loan	0.2	0.3
	Power Smart PAYS Financing	0.1	0.2
	Residential Earth Power Loan	0.2	0.3
		0.4	0.8
COMMERCIAL			
Incentive Based			
	Commercial Lighting Program	10.0	40.7
	LED Roadway Lighting Conversion Program	1.6	10.8
	Commercial Building Envelope - Windows Program	0.4	1.2
	Commercial Building Envelope - Insulation Program	0.8	1.9
	Commercial Geothermal Program	0.8	1.6
	Commercial HVAC Program - CO2 Sensors	0.4	0.7
	Commercial HVAC Program - HRVs	0.6	1.2
	Commercial HVAC Program - Air Cooled Chillers	-	1.3
	Commercial Custom Measures Program	0.4	1.7
	Commercial Building Optimization Program	0.2	0.9
	New Buildings Program	1.0	3.3
	Commercial Refrigeration Program	0.7	6.5
	Internal Retrofit Program	0.2	1.3
	Power Smart Shops	0.6	1.6
	Power Smart Energy Manager	0.2	0.9
	Race to Reduce	0.1	1.2
	Parking Lot Controller	-	-
		18.0	76.7
INDUSTRIAL			
	Performance Optimization Program	2.9	23.2
		2.9	23.2
LOAD MANAGEMENT			
	Curtailable Rate Program	145.0	-
		145.0	-
LOAD DISPLACEMENT & ALTERNATIVE ENERGY			
	Bioenergy Optimization Program	4.0	7.0
	Customer Sited Load Displacement	19.7	148.4
		23.7	155.4
CONSERVATION RATES			
	Conservation Rates - Residential	7.7	64.4
	Conservation Rates - Commercial	5.2	43.2
		12.9	107.6
FUEL CHOICE			
	Fuel Choice	25.5	51.1
		25.5	51.1
OTHER EMERGING TECHNOLOGIES			
	Residential Solar Thermal Program - Water Heating	0.0	0.0
	Residential Solar Thermal Program - Pool Heating	-	0.1
	Commercial Variable Speed and Frequency Drives	0.0	0.5
		0.0	0.6
	Planned DSM Savings (at meter)	235.1	435.8

c) The Commercial Parking Lot Controller Program has ended and will not be included in the 2019/20 DSM Plan. In addition, the Power Smart for Business PAYS Financing Program has been suspended and will not be included in the 2019/20 DSM Plan.

d) Both the Bioenergy Optimization Program and the Customer Sited Load Displacement Program have program activity that varies from year to year depending on the number, size and timing of projects. As well, decisions to proceed with a project and the timing of the project implementation are often driven by customers, and these decisions can change quickly and unexpectedly. The difference in the forecast savings for these programs in the 2017/18 DSM plan and the 2018/19 plan are based on Manitoba Hydro's knowledge of potential and ongoing projects at the time the DSM plan is created.

REFERENCE:

Application p. 21; 2018/19 DSM Plan p. 2; 2017/18 GRA PUB MFR 61 (2017/18 DSM Plan) p.2; 2017/18 GRA Appendix 7.2 2016/17 Power Smart Plan 15 Year Supplement p. 85 and 86 of 128

PREAMBLE TO IR (IF ANY):

On page 21 of the Application, Manitoba Hydro states:

The future program based DSM savings incorporated in the 2019/20 Interim Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for actual DSM savings achieved in 2017/18 and the carry-forward effects of the changes made to the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government.

Compared to the 2017/18 DSM Plan, the 2018/19 DSM Plan forecasts an additional 49.8 GWh of energy savings due to the Load Displacement Program and a decrease in energy savings of 17.8 GWh in the BioEnergy Optimization Program, for a net increase in savings of 32 GWh (at generation).

QUESTION:

a) Provide a breakdown of the 99 GWh increase in DSM savings over MH-93 identified on page 21 of the Application by DSM program. For the programs that are the greatest contributors (positive or negative) to the 99 GWh savings, explain the reasons for the change (i.e. program design change, customer uptake greater or less than previously anticipated, etc.).
b) Provide a table or tables that identify the changes in demand and energy savings between the 2016/17 Power Smart Plan 15 Year Supplement Appendix A.1 and A.2 and the 2019/20 Interim Budget assumptions for the 2019/20 test year, broken down by program. Explain any material differences.
c) Identify whether Manitoba Hydro has added or deleted any DSM programs from its portfolio of programs listed in the 2018/19 DSM Plan at page 2, or whether substantive changes have been made to these programs.

d) Explain the reasons for the decrease in the forecast of DSM savings for the BioEnergy Optimization Program and the increase in the DSM savings for the Load Displacement Program when comparing the 2018/19 DSM Plan to the 2017/18 DSM Plan. Have the Load Displacement Program savings expected in the 2018/19 DSM Plan been affected by the delayed implementation of customer-sited self-generation identified on page 21 of the Application?

RESPONSE:

The future program based DSM savings incorporated in the 2019/20 Approved Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for the carry-forward effects of the changes made to the 2017/18 one-year DSM plan and the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government.

a) The following table provides a breakdown of the difference in DSM savings in the 2019/20 Approved Budget provided in the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019 and the savings identified in Exhibit MH-93. Exhibit MH-93 covers a timeframe including 2017/18 to 2019/20. To provide the same timeframe for the comparison, the 2017/18 1-year DSM plan savings are added to the 2019/20 Approved Budget, which only includes the 2018/19 and 2019/20 time period, and the total is shown in the *Approved Budget Adjusted* column.

   The 2019/20 Approved Budget Adjusted represents a decrease of 298 GWh over Exhibit MH-93. The material differences are:

   - Customer Sited Load Displacement - The 86.2 GWh decrease reflects a delay in some projects expected to be completed in 2018/19 and 2019/20 to future years.
   - Conservation Rates – The 133.4 GWh decrease reflects the removal of the 2018/19 and 2019/20 forecast savings attributable to new programs which were planned to be introduced by Manitoba Hydro but have been suspended pending transition of responsibility for DSM programming and services to Efficiency Manitoba following consultation with the Province pursuant to *The Energy Savings Act*.

- Fuel Choice - The 102.2 GWh decrease reflects the removal of the 2018/19 and 2019/20 forecast savings attributable to new programs which were planned to be introduced by Manitoba Hydro but have been suspended pending transition of responsibility for DSM programming and services to Efficiency Manitoba following consultation with the Province pursuant to *The Energy Savings Act*.

Table: Comparison of Forecast DSM Savings by Program for 2017/18 to 2019/20

	2017/18 1 yr Plan	Approved Budget	Approved Budget Adjusted	Exhibit 93	Change
	GWh	GWh	GWh	GWh	GWh
	Persisting Savings in 2019/20	2018/19 and 2019/20 Activty	2017/18 to 2019/20	2017/18 to 2019/20	2017/18 to 2019/20
RESIDENTIAL	(A)	(B)	(C) = (A) + (B)	(D)	(E) = (D) - (C)
Incentive Based					
New Homes Program	0.8	5.6	6.4	2.7	3.7
Home Insulation Program	3.3	5.5	8.8	8.7	0.1
Affordable Energy Program	2.9	5.5	8.4	7.8	0.7
Water and Energy Saver Program	3.3	3.7	6.9	6.8	0.2
Refrigerator Retirement Program	8.0	12.3	20.3	22.1	-1.8
Drain Water Heat Recovery Initiative	0.0	0.0	0.0	0.0	0.0
Residential LED Lighting Program	17.4	23.4	40.9	21.1	19.7
Community Geothermal Program	1.9	2.7	4.6	8.8	-4.2
Appliances	0.5	2.1	2.6	0.5	2.1
HRV Controls	0.3	0.0	0.3	1.5	-1.2
Power Bars	0.0	0.0	0.1	0.0	0.0
Smart Thermostats	0.4	0.7	1.1	0.4	0.7
Plug-in Timers	0.1	0.5	0.6	0.1	0.5
Community Energy Plan	0.0	0.0	0.0	0.0	0.0
	38.9	62.1	101.0	80.5	20.6
Customer Service Initiatives / Financial Loan Programs					
Power Smart Residential Loan	0.2	0.5	0.7	0.9	-0.2
Power Smart PAYS Financing	0.1	0.2	0.3	0.5	-0.3
Residential Earth Power Loan	0.6	1.2	1.8	1.2	0.6
	0.9	1.8	2.7	2.6	0.1
COMMERCIAL					
Incentive Based					
Commercial Lighting Program	44.8	108.9	153.7	132.1	21.6
LED Roadway Lighting Conversion Program	11.5	23.3	34.9	33.3	1.6
Commercial Building Envelope - Windows Program	0.7	1.5	2.3	3.0	-0.7
Commercial Building Envelope - Insulation Program	3.1	4.5	7.6	6.7	0.8
Commercial Geothermal Program	0.6	0.7	1.4	3.4	-2.0
Commercial HVAC Program - Chillers (Water-Cooled)	1.0	0.0	1.0	1.0	0.0
Commercial HVAC Program - CO2 Sensors	0.2	0.2	0.4	1.6	-1.2
Commercial HVAC Program - HRVs	0.2	0.9	1.1	2.3	-1.2
Commercial HVAC Program - Air Cooled Chillers	0.0	0.0	0.0	2.5	-2.5
Commercial Custom Measures Program	1.7	4.0	5.7	5.1	0.6
Commercial Building Optimization Program	0.7	1.3	2.0	2.3	-0.3
New Buildings Program	6.2	5.7	12.0	12.0	0.0
Commercial Refrigeration Program	6.2	11.1	17.2	20.1	-2.9
Commercial Kitchen Appliance Program	0.2	0.2	0.4	0.2	0.2
Network Energy Management Program	0.1	0.2	0.3	0.4	-0.1
Internal Retrofit Program	0.0	0.0	0.0	0.0	0.0
Power Smart Shops	1.7	4.8	6.5	5.8	0.7
Power Smart Energy Manager	0.0	0.0	0.0	1.4	-1.4
Race to Reduce	3.8	1.6	5.4	6.5	-1.1
Parking Lot Controller	0.7	0.9	1.6	0.7	0.9
	83.5	169.8	253.3	240.4	12.9
Customer Service Initiatives / Financial Loan Programs					
Power Smart for Business PAYS Financing	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
INDUSTRIAL					
Performance Optimization Program	10.0	21.6	31.6	53.8	-22.2
	10.0	21.6	31.6	53.8	-22.2
LOAD DISPLACEMENT & ALTERNATIVE ENERGY					
Bioenergy Optimization Program	17.0	0.7	17.8	31.0	-13.3
Customer Sited Load Displacement	6.3	194.4	200.7	286.9	-86.2
	23.4	195.2	218.5	318.0	-99.5
CONSERVATION RATES					
Conservation Rates - Residential	0.0	0.0	0.0	90.2	-90.2
Conservation Rates - Commercial	0.0	0.0	0.0	43.2	-43.2
	0.0	0.0	0.0	133.4	-133.4
FUEL CHOICE					
Fuel Choice	0.0	0.0	0.0	102.2	-102.2
	0.0	0.0	0.0	102.2	-102.2
OTHER EMERGING TECHNOLOGIES					
Residential Solar Photovoltaics Program (PV)	0.5	15.7	16.2	0.5	15.7
Residential Solar Thermal Program - Water Heating	0.0	0.0	0.0	0.1	-0.1
Residential Solar Thermal Program - Pool Heating	0.0	0.0	0.0	0.1	-0.1
Commercial Solar Photovoltaics Program (PV)	0.5	11.1	11.6	0.5	11.1
Commercial Variable Speed and Frequency Drives	0.0	0.0	0.0	1.0	-1.0
	1.0	26.8	27.7	2.1	25.6
Planned DSM Savings (at meter)	**158**	**477**	**635**	**933**	**-298**

b) The following table outlines the changes in forecast demand and energy savings for the 2019/20 year between the 2016/17 Power Smart Plan 15 Year Supplement Appendix A.1 and A.2 and the 2019/20 Approved Budget provided in the Supplement to the 2019/20 Electric Rate Application filed on February 14, 2019.

The 2019/20 Approved Budget represents an increase of 0.8 MW and a decrease of 204 GWh over the 2016/17 Power Smart Plan 15 Year Supplement. The material differences are:

- Customer Sited Load Displacement – The 7.2 MW and 58.4 GWh decrease reflects a delay in some projects expected to be completed in 2019/20 to future years.
- Conservation Rates – The 12.9 MW and 107.6 GWh decrease reflects the removal of the 2019/20 forecast savings attributable to new programs which were planned to be introduced by Manitoba Hydro but have been suspended pending transition of responsibility for DSM programming and services to Efficiency Manitoba following consultation with the Province pursuant to *The Energy Savings Act*.
- Fuel Choice - The 25.5 MW and 51.1 GWh decrease reflects the removal of the 2019/20 forecast savings attributable to new programs which were planned to be introduced by Manitoba Hydro but have been suspended pending transition of responsibility for DSM programming and services to Efficiency Manitoba following consultation with the Province pursuant to *The Energy Savings Act*.
- Curtailable Rates – The 48.8 MW increase reflects the addition of forecast savings from Option R in the 2019/20 Approved Budget which had not been included in the 2016/17 Power Smart Plan 15 Year Supplement.

Table: Comparison of Forecast DSM Savings by Program for the 2019/20 Test Year

	Approved Budget		2016/17 DSM Plan		Change	
	2019/20 MW	2019/20 GWh	2019/20 MW	2019/20 GWh	2019/20 MW	2019/20 GWh
RESIDENTIAL						
Incentive Based						
New Homes Program	1.4	2.8	0.3	1.0	1.1	1.8
Home Insulation Program	1.2	2.7	1.3	2.6	(0.1)	0.1
Affordable Energy Program	0.7	2.1	1.0	2.4	(0.3)	(0.3)
Water and Energy Saver Program	0.2	1.8	-	-	0.2	1.8
Refrigerator Retirement Program	0.6	5.7	0.6	6.2	(0.0)	(0.5)
Drain Water Heat Recovery Initiative	-	-	-	-	-	-
Residential LED Lighting Program	3.4	10.8	1.5	4.7	1.9	6.1
Community Geothermal Program	0.5	1.0	1.8	3.6	(1.3)	(2.6)
Appliances	0.1	1.0	-	-	0.1	1.0
HRV Controls	-	-	-	-	-	-
Power Bars	0.0	0.0	-	-	0.0	0.0
Smart Thermostats	0.1	0.3	-	-	0.1	0.3
Plug-in Timers	0.0	0.2	-	-	0.0	0.2
Community Energy Plan	-	-	-	-	-	-
	8.3	28.3	6.5	20.4	1.8	8.0
Customer Service Initiatives / Financial Loan Programs						
Power Smart Residential Loan	0.1	0.2	0.2	0.3	(0.0)	(0.1)
Power Smart PAYS Financing	0.0	0.1	0.1	0.2	(0.1)	(0.1)
Residential Earth Power Loan	0.3	0.6	0.2	0.3	0.1	0.3
	0.4	0.9	0.4	0.8	0.0	0.1
COMMERCIAL						
Incentive Based						
Commercial Lighting Program	13.3	55.5	10.0	40.7	3.3	14.9
LED Roadway Lighting Conversion Program	1.5	10.7	1.6	10.8	(0.1)	(0.2)
Commercial Building Envelope - Windows Program	0.3	0.7	0.4	1.2	(0.1)	(0.5)
Commercial Building Envelope - Insulation Program	0.8	1.7	0.8	1.9	(0.0)	(0.2)
Commercial Geothermal Program	0.2	0.4	0.8	1.6	(0.7)	(1.3)
Commercial HVAC Program - CO2 Sensors	0.0	0.1	0.4	0.7	(0.4)	(0.6)
Commercial HVAC Program - HRVs	0.3	0.7	0.6	1.2	(0.3)	(0.5)
Commercial HVAC Program - Air Cooled Chillers	-	-	-	1.3	-	(1.3)
Commercial Custom Measures Program	0.3	2.2	0.4	1.7	(0.1)	0.5
Commercial Building Optimization Program	0.1	0.5	0.2	0.9	(0.1)	(0.4)
New Buildings Program	1.0	3.3	1.0	3.3	-	-
Commercial Refrigeration Program	0.4	3.4	0.7	6.5	(0.2)	(3.1)
Commercial Kitchen Appliance Program	0.0	0.1	-	-	0.0	0.1
Network Energy Management Program	0.0	0.0	-	-	0.0	0.0
Internal Retrofit Program	0.1	0.9	0.2	1.3	(0.1)	(0.4)
Power Smart Shops	0.7	3.0	0.6	1.6	0.1	1.4
Power Smart Energy Manager	-	-	0.2	0.9	(0.2)	(0.9)
Race to Reduce	0.1	0.8	0.1	1.2	(0.0)	(0.4)
	19.2	83.9	18.0	76.7	1.2	7.1
INDUSTRIAL						
Performance Optimization Program	1.4	9.2	2.9	23.2	(1.5)	(14.0)
	1.4	9.2	2.9	23.2	(1.5)	(14.0)
LOAD MANAGEMENT						
Curtailable Rate Program	193.9	-	145.0	-	48.8	-
	193.9	-	145.0	-	48.8	-
LOAD DISPLACEMENT & ALTERNATIVE ENERGY						
Bioenergy Optimization Program	0.2	0.7	4.0	7.0	(3.8)	(6.3)
Customer Sited Load Displacement	12.5	90.0	19.7	148.4	(7.2)	(58.4)
	12.7	90.7	23.7	155.4	(11.0)	(64.7)
CONSERVATION RATES						
Conservation Rates - Residential	-	-	7.7	64.4	(7.7)	(64.4)
Conservation Rates - Commercial	-	-	5.2	43.2	(5.2)	(43.2)
	-	-	12.9	107.6	(12.9)	(107.6)
FUEL CHOICE						
Fuel Choice	-	-	25.5	51.1	(25.5)	(51.1)
	-	-	25.5	51.1	(25.5)	(51.1)
OTHER EMERGING TECHNOLOGIES						
Residential Solar Photovoltaics Program (PV)	-	9.2	-	-	-	9.2
Residential Solar Thermal Program - Water Heating	-	-	0.0	0.0	(0.0)	(0.0)
Residential Solar Thermal Program - Pool Heating	-	-	-	0.1	-	(0.1)
Commercial Solar Photovoltaics Program (PV)	-	9.3	-	-	-	9.3
Commercial Variable Speed and Frequency Drives	-	-	0.0	0.5	(0.0)	(0.5)
	-	18.5	0.0	0.6	(0.0)	17.9
Planned DSM Savings (at meter)	**236**	**232**	**235**	**436**	**0.8**	**(204)**

c) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

d) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

REFERENCE:

Application p. 15-16; 2017/18 GRA Tab 5 p. 26; PUB/MH I-117b-d

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide tables similar to 2017/18 GRA Tab 5 page 26 Figure 5.11 showing the Business Operations Capital by Investment Category for 2019/20.

RESPONSE:

Please see table below for Business Operations Capital by Investment Category.

CEF18 Electric Business Operations Capital by Investment Category ($ Millions)	2019/20
Capacity & Growth	
System Load Capacity	163.3
Customer Connections - Residential, Commercial & Industrial	42.4
Total Capacity & Growth	**205.6**
Sustainment	
System Renewal	155.0
Mandated Compliance	35.4
System Efficiency	8.7
Decommissioning	0.1
Total Sustainment	**199.3**
Business Operations Support	
Town site Infrastructure	43.8
Corporate Facilities	22.1
Information Technology	17.3
Fleet	17.0
Tools and Equipment	5.3
Total Business Operations Support	**105.6**
Total Electric Business Operations Capital	**510.5**

REFERENCE:

Application p. 15-16; 2017/18 GRA Tab 5 p. 26; PUB/MH I-117b-d

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide tables similar to 2017/18 GRA Tab 5 page 26 Figure 5.11 showing the Business Operations Capital by Investment Category for 2019/20.

RESPONSE:

The table below provides the Investment Category breakdown for the Business Operations Capital 2019/20 Approved Budget as provided in Section 5.0 of the Supplement to the 2019/20 Electric Rate Application.

Electric Business Operations Capital by Investment Category ($ Millions)	**2019/20 Approved Budget**
Capacity & Growth	
System Load Capacity	119.4
Customer Connections - Residential, Commercial & Industrial	35.5
Total Capacity & Growth	**154.9**
Sustainment	
System Renewal	164.2
System Efficiency	38.7
Mandated Compliance	30.3
Decommissioning	2.4
Total Sustainment	**235.5**
Business Operations Support	
Town site Infrastructure	30.4
Information Technology	23.3
Fleet	15.0
Corporate Facilities	13.8
Tools and Equipment	4.7
Total Business Operations Support	**87.1**
Total Electric Business Operations Capital	**477.5**

REFERENCE:

Application p. 15-16; 2017/18 GRA Tab 5 p. 26; PUB/MH I-117b-d

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please indicate what proportion of the 2019/20 investment in each category is considered by Manitoba Hydro to be non-volitional and therefore not able to be considered for deferral in a similar format to that shown in PUB/MH I-117 from the 2017/18 GRA.

c) Explain why the volitional projects and programs are being done in the test year.

RESPONSE:

Response to b) & c):

Manitoba Hydro's response to PUB/MH I-117 from the 2017/18 GRA categorized investments based on the risk (probability x operational consequence) of deferral. Investments with almost certain negative consequences of deferral were categorized as non-deferrable and investments with less certainty of negative consequence were categorized as eligible for deferral subject to the acceptability of risk. This categorization appears to have caused some confusion as to the time-sensitivity of planned investments.

All planned investments are operationally driven in support of Manitoba Hydro's responsibility to provide for an ongoing safe and reliable supply of electricity to its customers. Deferral is a question of risk gauged against tolerance for potential consequences. All investments could be deferred with an unlimited consequence tolerance, even if the probability of consequence was certain. However, consequence tolerance is necessarily limited and the probability of consequence is rarely certain, thereby making investment timing a complex risk decision. As such, Manitoba Hydro cannot indicate what proportion of the planned 2019/20 investments in each investment category is volitional.

Given that electricity is an essential service for Manitobans, and it is Manitoba Hydro's mandate to serve as the sole provider of electricity in the province, the tolerance for jeopardizing the ongoing safe and reliable supply of electricity to customers is appropriately low. The operability and sustainability of the system are continually being eroded by inevitable asset degradation, shifting customer demands, and growing operational requirements, which are mitigated through investment.

The primary justification for the investments from CEF18 is shown in the table in response to PUB/MH I-51a by the two levels of Investment Category. Capacity & Growth investments address new and growing customer needs, while Sustainment investments keep the system functioning for existing customers, and Business Operations Support investments assure continuity of operations and customer service.

The timing of investment is a complex risk decision with significant potential operational and cost consequences. Manitoba Hydro considers the timing of investment execution as part of its annual capital planning process, based on the best information available at the time, and adjustments are made as new information becomes available. Only those investments associated with unacceptable risks to the operability or sustainability of the system are advanced to execution. Less critical potential investments are deferred and revisited in future planning cycles such that potential investments being advanced to execution in the current year may have been repeatedly deferred in previous planning cycles. During the year, adjustments to the plan may also occur if anticipated risk exposures do not come to fruition.

The forecasted investments for 2019/20 (per CEF18) include a mix of items in the execution stage as well as potential new starts. Investments for the 2019/20 year are being reviewed as part of the 2019/20 budget cycle where potential investments are considered for advancement to execution based on the current urgency of the work and limiting constraints. Only those investments necessary to meeting Manitoba Hydro's responsibility to provide for an ongoing safe and reliable supply of energy to its customers will be included in the 2019/20 investment plan.

The 2019/20 budget cycle is currently underway and will produce an investment plan for 2019/20 and an associated budget, which will be filed following approval from the MHEB and province. Manitoba Hydro's longer term Capital Expenditure Forecast will be reviewed along with the Integrated Financial Forecast and filed at the next General Rate Application.

As the approved 2019/20 plan will include only investments required to mitigate unacceptable risks to Manitoba Hydro's responsibility to provide for an ongoing safe and reliable supply of energy to its customers, none of the investments will be eligible for further deferral at this time. However, as noted above, adjustments will be made throughout the year as new information becomes available.

REFERENCE:

Appendix 6 CEF18; 2017/18 GRA Tab 5 p. 26

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a table comparing the forecast Business Operations Capital spending for 2017/18 from CEF16 (and MH16-Update) against actual spending, broken down by Generation, Transmission, Distribution, and Corporate Assets. Explain any material variances.
b) Provide a table comparing the forecast Business Operations Capital in-service additions for 2017/18 from CEF16 (and MH16-Update) against actual in-service additions, broken down by Generation, Transmission, Distribution, and Corporate Assets. Explain any material variances.

RESPONSE:

a) The following table provides a comparison of 2017/18 actual spending compared to CEF16 forecast for Business Operations Capital. MH16-Update did not contain any adjustments for Business Operations Capital. Explanations have been provided for material variances which occurred in Transmission, Distribution and Corporate Assets.

MANITOBA HYDRO
ELECTRIC BUSINESS OPERATIONS CAPITAL
FOR THE YEAR ENDED MARCH 31, 2018
(in millions of dollars)

	CEF16 FORECAST	Actual	Variance
Generation	$ 95	$ 89	$ 6
Transmission	132	107	25
Distribution	243	228	16
Corporate Assets	55	37	18
Business Operations Capital	**$ 526**	**$ 461**	**$ 65**

The variance in Transmission is primarily related to an under expenditures within four major projects:

- Steinbach Area 230-66kV Capacity Enhancement – primarily due to the revised design schedule for the 66kV lines and rescheduled equipment and material deliveries to align with an updated construction schedule.
- Dorsey Synchronous Condenser Refurbishment – due to the deferral of a controls upgrade to accommodate Bipole III commissioning which requires all Dorsey synchronous condensers to be available until post Bipole III in-service.
- Transmission Line Upgrades for Improved Clearance – due to a reduction in scope of transmission lines that required upgrades to improve clearance.
- Lake Winnipeg East System Improvements – primarily due to favourable bid pricing for the Electrical and Civil Construction contracts as well as delayed transmission line commissioning as a result of contractor performance.

The variance in Distribution is primarily related to an under expenditure on the Panet Station 66/24kV project due to the completion of a detailed project plan in 2017/18 which deferred a significant portion of the construction spending to 2018/19.

The variance in Corporate Assets is primarily related to delays in various initiatives due to a need to assess the impacts of the Voluntary Departure Program and corporate restructuring on facility and information technology projects and programs.

b) The following table provides a comparison of forecast versus actual in-service additions related to Business Operations Capital for 2017/18. The target adjustment reflects a reduction of the in-service forecast for 2017/18 as a result of the year end outlook expenditure adjustment of $(45) million in 2016/17. A material variance explanation occurred in Transmission and has been explained following the table.

MANITOBA HYDRO
ELECTRIC BUSINESS OPERATIONS CAPITAL
IN-SERVICE ADDITIONS
FOR THE YEAR ENDED MARCH 31, 2018
(In millions of dollars)

	CEF16 Forecast	Actual	Variance
Generation	$ 109	$ 112	$ (3)
Transmission	182	82	100
Distribution	280	287	(7)
Corporate Assets	58	48	10
Target Adjustment	(45)	-	(45)
	$ 585	**$ 529**	**$ 56**

The Transmission in-service addition variance was primarily due to a delay of in-service for the Lake Winnipeg East System Improvements project. The project was delayed 10 months to July 2018 as the contractor was unable to complete the transmission line in the 2016/17 winter season due to low productivity and access restrictions, and required another winter construction season to complete.

REFERENCE:

Application p. 15-16; Appendix 6 CEF18 p. 32; Order 59/18 Recommendation to Manitoba Hydro No. 1

PREAMBLE TO IR (IF ANY):

With respect to the Board's recommendation in Order 59/18 to defer Business Operations Capital spending in 2018/19 by $160 million, Manitoba Hydro states:

the projects identified in the 2018/19 Financial Outlook are projects which are active and cannot be cancelled without a cost to the safe and reliable services being provided. Manitoba Hydro will continue to assess active projects on an on-going basis which may impact timing, investments may be reduced accordingly.

CEF18 p. 32 details the changes in forecast capital spending between CEF16 and CEF18, showing Business Operations Capital spending increasing by $1.1 million in 2019/20.

QUESTION:

Explain why Manitoba Hydro did not defer Business Operations Capital spending in 2019/20 if, as stated by Manitoba Hydro, it was too late to defer projects and decrease spending in 2018/19 due to projects already being active.

RESPONSE:

Deferral of capital spending in 2019/20 is currently being considered as part of the 2019/20 budget process. Please see response to PUB/MH I-51 b-c for further details.

REFERENCE:

Application p. 15-16; Appendix 6 CEF18 p. 32; Order 59/18 Recommendation to Manitoba Hydro No. 1

PREAMBLE TO IR (IF ANY):

With respect to the Board's recommendation in Order 59/18 to defer Business Operations Capital spending in 2018/19 by $160 million, Manitoba Hydro states:

the projects identified in the 2018/19 Financial Outlook are projects which are active and cannot be cancelled without a cost to the safe and reliable services being provided. Manitoba Hydro will continue to assess active projects on an on-going basis which may impact timing, investments may be reduced accordingly.

CEF18 p. 32 details the changes in forecast capital spending between CEF16 and CEF18, showing Business Operations Capital spending increasing by $1.1 million in 2019/20.

QUESTION:

Explain why Manitoba Hydro did not defer Business Operations Capital spending in 2019/20 if, as stated by Manitoba Hydro, it was too late to defer projects and decrease spending in 2018/19 due to projects already being active.

RESPONSE:

The assessment of investment requirements is an ongoing process in which forecasts and plans are updated to reflect the new information as it becomes available. Business Operations Capital ("BOC") targets are set annually within Manitoba Hydro's planning cycle as portfolio plans are developed for the coming year and forecasts of investment requirements are updated for the years beyond. The 2019/20 year as it appeared in CEF18 was the year beyond the budget year and therefore did not have a detailed portfolio plan. As per Manitoba Hydro's Supplement to the 2019/20 Electric Rate Application, the target for 2019/20 was reduced from CEF18 by $37M to $478M when the 2019/20 budget was created. The approved budget reflects the investments planned in 2019/20 to ensure the short term operability and long term sustainability of the electric system.

Please see Manitoba Hydro's response to PUB/MH I-51b-c for further discussion on the timing of investment.

REFERENCE:

Application Appendix 7

PREAMBLE TO IR (IF ANY):

QUESTION:

File the public and CSI quarterly reports on major new generation and transmission projects in response to Order 59/18 Directive 16 for the period October 1 to December 31, 2018 when available.

RESPONSE:

Please see the attached for Manitoba Hydro's quarterly reports on Major New Generation & Transmission ("MNG&T") capital projects for the quarter ended December 31, 2018 which were filed with the PUB on February 14, 2019 in accordance with Directive 16 of Order 59/18.

Consistent with the PUB's ruling as set forth in its letter of February 5, 2019, Manitoba Hydro also filed in confidence pursuant to Rule 13(2) of the PUB Rules of Practice and Procedure, the detailed Confidential Quarterly Reports on MNG&T projects as these reports contained commercially sensitive information which if publicly disclosed would harm Manitoba Hydro's ability to manage and execute the work according to the commercial terms agreed to by contract, would affect future negotiations and put Manitoba Hydro at risk of undue financial loss.

Manitoba Hydro Update on Major Projects to the Public Utilities Board

Bipole III Project Update

Q3 Update ending December 31, 2018

Bipole III transmission tower - N4 –addition of corona ring stiffeners

EXECUTIVE SUMMARY

Project Description

Bipole III is a high voltage direct current transmission line that delivers renewable energy to southern Manitoba. Bipole III went into operation in July of 2018.

The Bipole III project included:

- A 1,384-kilometre, 500,000-volt direct current transmission line;
- The Keewatinohk Converter Station in northern Manitoba, northeast of Gillam;
- The Riel Converter Station, east of Winnipeg;
- 230 kV collector lines (5); and,
- Two ground electrodes at each of the new converter stations.

Bipole III adds 2,000 megawatts to Manitoba Hydro's high voltage direct transmission and strengthens the reliability of Manitoba's electricity supply by reducing dependency on existing high voltage direct current transmission lines and the Dorsey Converter Station. Prior to Bipole III, the two existing Bipole lines delivered over 70 per cent of the electricity produced in the province.

Due to its heavy reliance on one transmission corridor and a single converter station in the south (Dorsey), Manitoba Hydro's electricity system was vulnerable to extensive power outages from severe weather (major ice storm, extreme wind event, tornado), fires, or other events. The Riel Converter Station established a second converter station in southern Manitoba, to provide another major point of power injection into the transmission and distribution system.

Background

The Bipole III Project Environment Act Licence was issued August 14, 2013. In fall 2016, a review of the Bipole III budget and schedule was conducted and the budget was increased to $5.04 billion with an in-service date of July 2018.

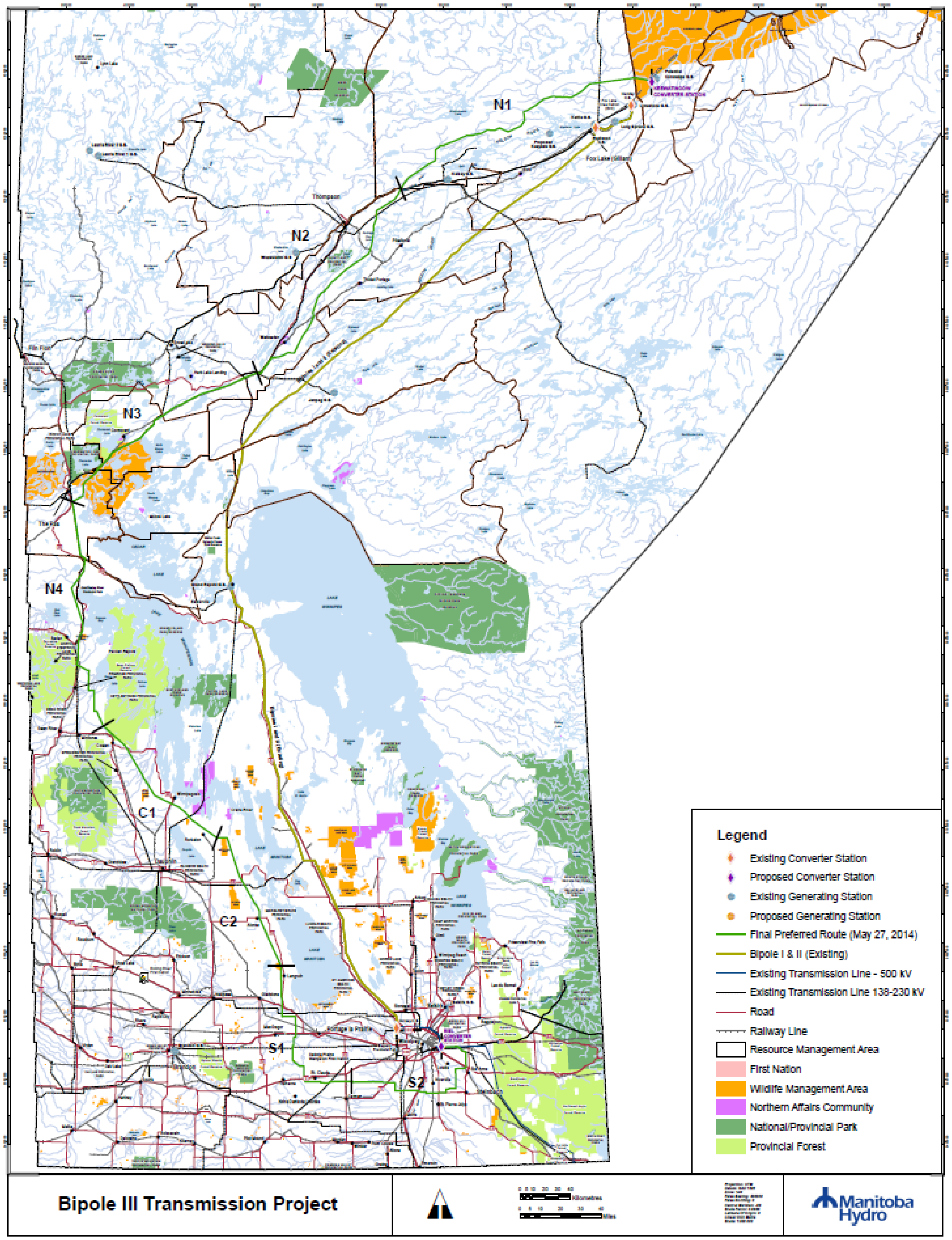
Keewatinohk and Riel Converter Stations
The Bipole III transmission line originates at a new northern converter facility, the Keewatinohk Converter Station, and terminates at a new southern converter facility, the Riel Converter Station. In addition to the new transmission line and the new converter stations, the project included new collector lines linking the Keewatinohk Converter Station to the northern collector system at the existing switchyards at Henday Converter Station and Long Spruce Generating Stations. Each of those facilities required some modifications for these new "collector lines". Each of the new converter stations required the development of a separate ground electrode, connected to the station by a low voltage feeder line.

Transmission Line Construction

The Keewatinohk Converter Station and the Riel Converter Station are linked by a new +/- 500 kV HVDC transmission line approximately 1,384 km in length, centered on a 66 meter wide right-of-way following a route west of lakes Winnipegosis and Manitoba. This new transmission line has been routed as far as practical, sufficiently far from the existing Bipole I and II lines so as to decrease the probability that a single catastrophic weather event or natural disaster would damage both the new transmission line and Bipoles I and II.

Below please find a map of the transmission line segments.

Map of the Bipole III Project



PROJECT UPDATE

On July 4, 2018 Bipole III was turned over for commercial service to Manitoba Hydro operations. With Bipole III now in-service, Manitoba Hydro has been balancing the transmission of HVDC power from northern Manitoba across Bipoles I, II and III.

Construction of the fourth and final synchronous condenser at the Riel Converter Station was completed and turned over for commercial service on November 17, 2018.

The remaining work on the Bipole III Project includes final clean up and the decommissioning of temporary construction infrastructure. At the Keewatinohk Converter Station, work also continues on the construction of the permanent staff accommodations and the water treatment plant.

As part of the decommissioning of the Keewatinohk Lodge, a contract for brokering the sale of the Keewatinohk Lodge was awarded in November, 2018. It is expected the Lodge will be publicly advertised for sale in January 2019.

At the Riel Converter Station site, the contractor's field office trailers and associated temporary infrastructure and the temporary construction power have been decommissioned and removed.

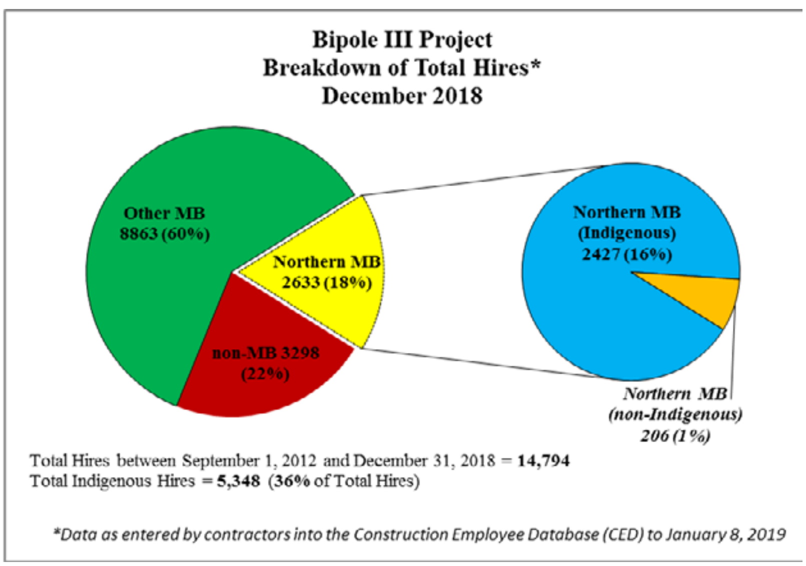
Total Hires: – as of December 31, 2018

- Since September 2012 there have been a total of 14,794 hires to the Bipole III project.
- Of the total hires, 78% have been Manitoban, including 18% northern Manitobans.
- 36% of total hires have self-declared as being Indigenous.
    - 38% of Keewatinohk, 16% of Riel and 46% of the hires for the transmission line have self-declared as being Indigenous.

Active hires are no longer being reported under the Project.

The number of total hires will be updated as contractors submit their final employment reports.

Additional information is provided below regarding the percentage of project hires (Manitoban – both Northern and Other, along with non-Manitobans).



FINANCIAL SUMMARY

- A Recommendation was approved by Manitoba Hydro's Major Project Executive Committee (MPEC) on August 28, 2018 to reduce the Bipole III control budget by $271.8 million from $5.04 billion to approximately $4.77 billion. The new control budget will be updated to reflect this number in IFF19/CEF19.
- Expenditures were $4.467 Billion to the end of December 31, 2018.

Table A - Bipole III Budget Summary (in Billions $)

Item #	Item	Current Approved Budget (2016$)	Actuals to Dec 31, 2018
1.1	Transmission Line	1.457	1.510
1.2	Converter Stations	2.285	2.276
1.3	Collector Lines	0.199	0.193
1.4	Community Development Initiative	0.053	0.053
1.5	Escalation @ CPI	0.052	0.000
1.6	Interest (Capitalized)	0.487	0.435
1.7	Contingency	0.509	0.000
1.8	Total	5.042	4.467

Table A Notes:

1. The Escalation and Contingency Components (1.5 and 1.7) will have no actual costs incurred against them; these costs will form part of the actual costs in the Transmission Line, Converter Stations, Collector Lines, Community Development Initiative and Interest Components (1.1, 1.2, 1.3, 1.4 and 1.6).

Manitoba Hydro Update on Major Projects to the Public Utilities Board

Keeyask Project Update

Q3 Update ending December 31, 2018

EXECUTIVE SUMMARY

- Entering the 2018 construction season, the project required at least a 10% improvement in the General Civil Contract (“GCC”) performance for the remainder of their work and no substantive risks to materialize to achieve the control budget.
- Significant progress was achieved in the 2018 construction season and all key milestones were achieved. In 2018, the GCC placed 32% more concrete and moved 27% more earth material than in 2017. As a result of the strong performance in 2018, the cost of the project is tracking to the $8.7B control budget. The first unit In-Service Date (ISD) is trending towards 10 months ahead of schedule. Schedule advances have helped to lower the forecasted project costs and are the main reason the project is now tracking to meet its budget of $8.7B. Even with these advances, Manitoba Hydro is committed to find ways to lower costs as there is still a lot of work and risks remaining.
- The control budget for the project remains at $8.7B. There are currently no changes in budget that would impact domestic revenue requirements or Manitoba Hydro’s financial forecasts.
- Actual expenditures to the end of December 31, 2018 were $5.53 billion.

PROJECT UPDATE

Background

- The Keeyask Generating Station is a 7 unit, 695-megawatt hydroelectric generating station under construction at Gull Rapids on the lower Nelson River in northern Manitoba.
- The Keeyask Project is a collaborative effort between Manitoba Hydro and four Manitoba First Nations, working together as the Keeyask Hydropower Limited Partnership.
- Keeyask will be Manitoba's fourth largest generating station and the sixth on the Nelson River.
- Construction of the Keeyask Generating Station commenced on July 16, 2014 after receipt of all required licenses and approvals.
- The Keeyask Project includes construction of the generating station as well as construction of supporting infrastructure. Most of the supporting infrastructure was constructed in advance of commencement of construction of the generating station under the Keeyask Infrastructure Project (KIP).
- The General Civil Works contract, the largest contract on the project, was awarded to BBE Hydro Constructors Limited Partnership consisting of Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. The General Civil Works contractor is responsible for rock excavation, concrete for the powerhouse and spillway, earth structures, electrical and mechanical work, and the construction and removal of temporary cofferdams needed to manage the river flow during construction.

Generating Station

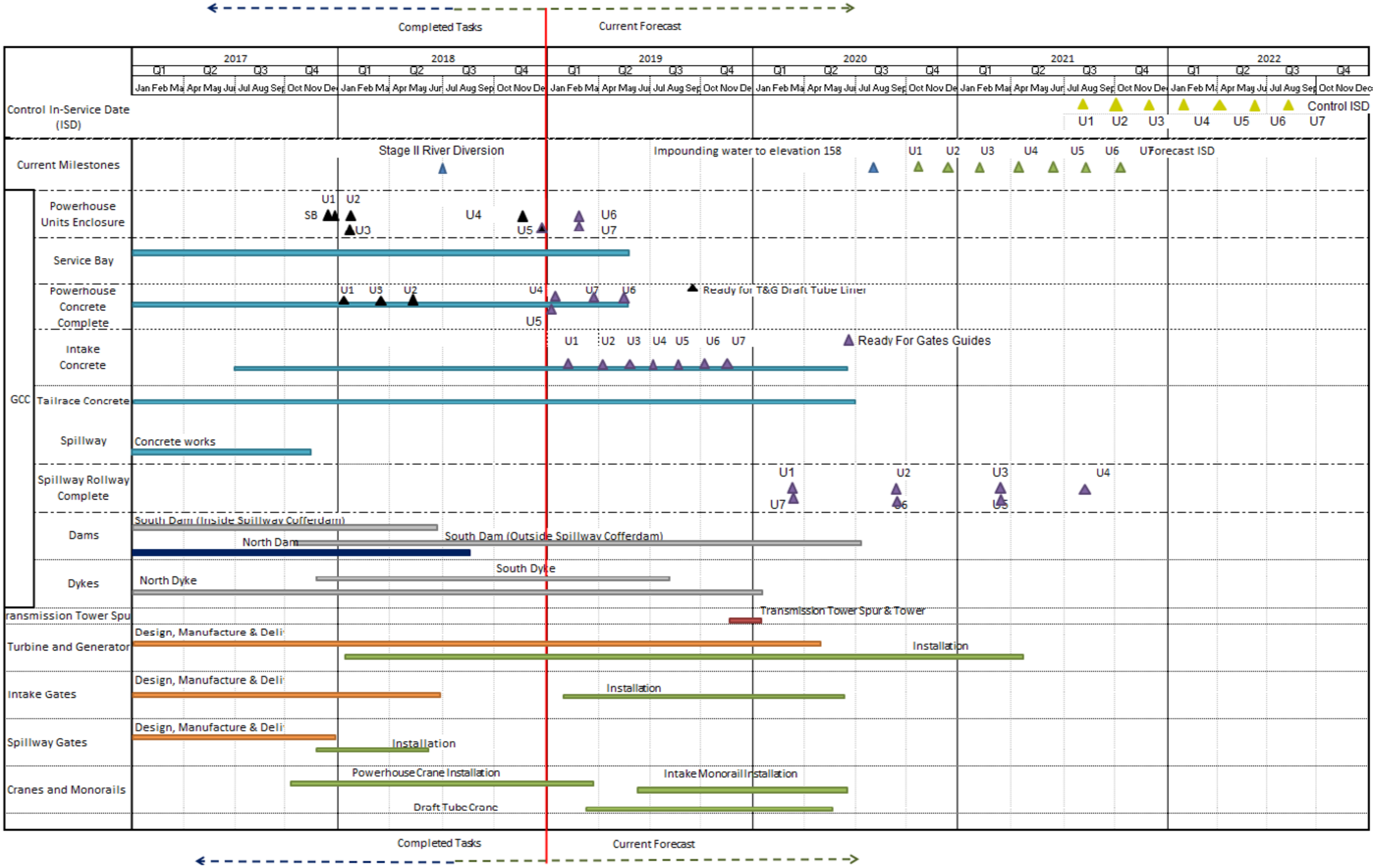
- The General Civil Works Contractor (GCC) exceeded the 2018 goal of 105,000 m^3 of concrete, placing more than 113,000 m^3 this year. This volume represents a year-over-year improvement of approximately 32% over 2017. In total there has been approximately 276,000 m^3 of concrete placed on the project; approximately 85 per cent of the total volume of concrete required for the Keeyask Project.
- In addition to the significant concrete progress, all 2018 milestones were met or exceeded. The key milestones achieved in 2018 include the following:
    - completion of the Spillway, River Diversion and opening/operation of the Spillway in August 2018;
    - opening of the South Access Road to construction traffic;
    - placement of 3.6 million m^3 of earth material (equivalent to 180,000 truckloads), exceeding the 2017 earthworks production by 27%;
    - installation of the planned embedded Turbine and Generator (T&G) components on units 1,2&3;

    - enclosure of units 4&5 to allow for the installation of embedded T&G components over the winter 2019.
- The top risks include:
    - Execution/productivity rates of the GCC and/or the T&G contractor;
    - Loss of site access/work stoppages due to a blockade or a major safety/environmental event;
    - Unseasonable weather that shortens the warm construction season.
- By the end of 2018, excavation has progressed for the South Dam and South Dyke to the point where unexpected geotechnical/geological conditions for these structures is no longer considered a top risk item for the project.

Infrastructure

- There are no infrastructure updates for the project over the previous quarter.

Project Schedule Overview – December 31, 2018

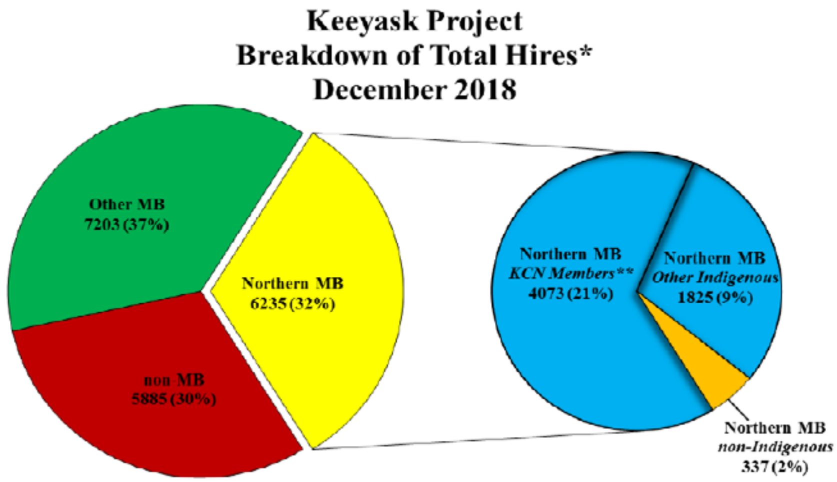


Note: Construction activities, milestones and unit ISDs reflect Manitoba Hydro's current forecast schedule. Presently, the forecast for the unit ISDs is in advance of the Control ISDs (August 2021 for first unit ISD).

* This is a summary of MH's current plan broken down to the major component of construction and significant contractors, and how these components and milestones relate to river management and impoundment.
* "Control ISD" reflects MH communicated In-Service-Date ("ISD") dates, while "Current ISD" reflects current planned ISD dates which are currently 10 months ahead of the control ISD.
* Powerhouse concrete remains the project critical path driving the water impoundment. Construction of the dams and dykes are currently off the critical path.
*MH and Voith are working together to rework the Turbine and Generator schedule.

Legend:
U = Unit
ISD = In Service Date
SW = Spillway
U/S = Up Stream
C/D = Cofferdam
D/S = Downstream
T&G = Turbine and Generator
PH = Powerhouse
CM = Contract Milestone
GCC = General Civil Contract

Total Project Hires – as of December 31, 2018



- As of December 31, 2018, there have been a total of 19,323 hires on the Keeyask Project. Of these total hires, 70% (13,438) are Manitobans, 43% (8,270) have self-declared as being Indigenous persons and 21% (4,093) of the total hires are Keeyask Cree Nation ("KCN") members.

Active Hires – as of December 31, 2018

- As of December 31, 2018 there were 3,068 active hires on the Keeyask Project. Of these active hires, 55% (1,677) are Manitobans, 29% (875) have self-declared as being Indigenous persons and 13% (399) are KCN members.

FINANCIAL SUMMARY

- Actual expenditures to the end of December 31, 2018 were $5.53 billion.

Table A - Keeyask Budget Summary (in Billions $)			
Item #	**Item**	**Current Approved Budget (2016$)**	**Actuals to December 31, 2018**
1.1	Generating Station	5.948	4.624
1.2	Generation Outlet Transmission (GOT)	0.202	0.144
1.3	Escalation @ CPI	0.249	0.000
1.4	Interest (including Interest on Equity)	1.749	0.761
1.5	Contingency	0.578	0.000
	Total	**8.726**	**5.529**

Table A Notes:
1. The Escalation and Contingency Components (1.3 and 1.5) will have no actual costs incurred against them; these costs will form part of the actual costs in the Generating Station, Generation Outlet Transmission and Interest Components (1.1, 1.2 and 1.4).

RECENT PHOTOS

The following photos are intended to represent the progress achieved in during the 2018 construction season. Photos from earlier and later in the year are provided.

Photo #1: Powerhouse Construction with Units 1 to 3 Enclosed – January 25, 2018

Photo #2: Powerhouse Construction with Units 4 and 5 Now Enclosed – December 9, 2018

Photo #3: Unit 1 Draft Tube Liner Lifted Into Place – January 21, 2018

Photo #4: Powerhouse Interior, Embedded Parts for Units 1-3 Installed – November 5, 2018

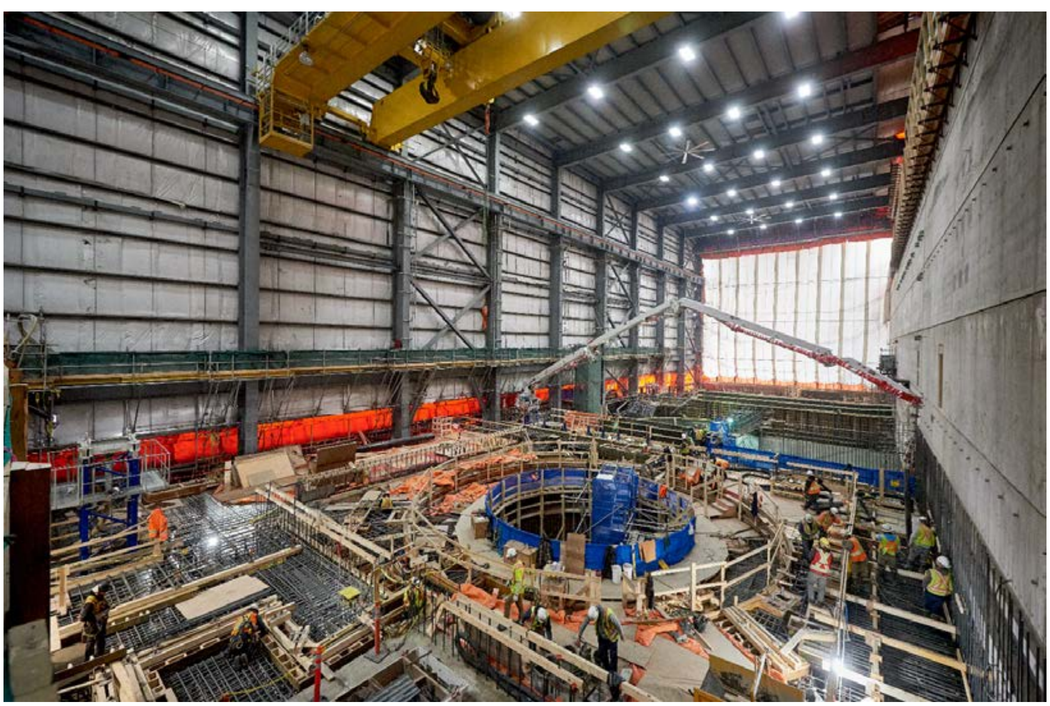


Photo #5: Intake Construction – January 20, 2018

Photo #6: Intake Construction – November 21, 2018

Photo #7: Spillway – June 24, 2018

Photo #8: Spillway – December 12, 2018

Photo #9: Central Dam – May 21, 2018

Photo #10: Central Dam – October 23, 2018

Photo #11: South Dam – early July 2018

Photo #12: South Dam – December 5, 2018

MMTP Project Description

Manitoba Hydro’s capital expenditure forecast includes the construction of a new 500kV Transmission Line between Winnipeg and Duluth, Minnesota (MMTP).

The MMTP transmission line will originate at Dorsey Converter station located near Rosser, northwest of Winnipeg and extend 213 km south around Winnipeg to the Manitoba-Minnesota border, near Piney, Manitoba. The MMTP also includes associated upgrades at Dorsey, Riel and Glenboro stations.

The U.S. portion of the 500 kV line will initiate at the border and terminate at Iron Range Station near Grand Rapids, Minnesota. This project is known as the Great Northern Transmission Line (GNTL), and is being constructed by Minnesota Power.

MMTP Project Update

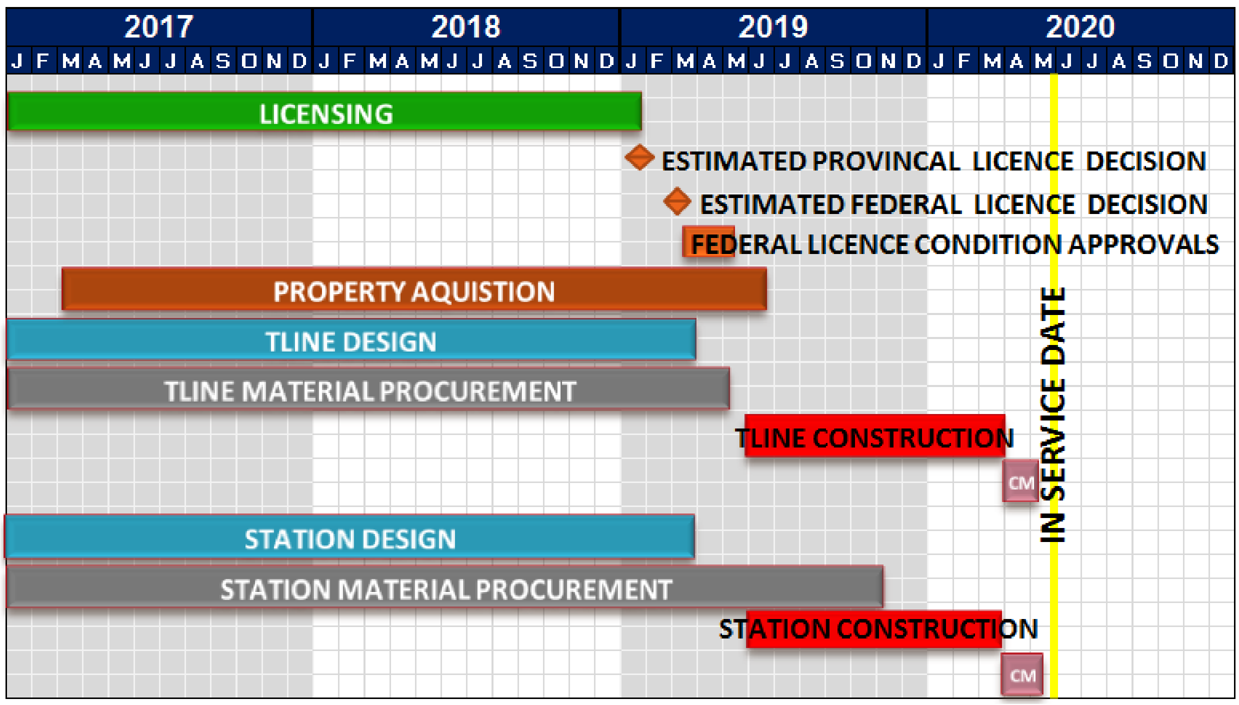
- Manitoba Hydro is awaiting a licensing decision by Manitoba Sustainable Development. Sagkeeng First Nation has put their request for judicial review of MMTP into abeyance until licensing decisions have been made.
- On November 15, 2018, the National Energy Board (NEB) released its Reasons for Decision report on MMTP determining “the Project is and will be required by the present and future public convenience and necessity” and recommending the Governor in Council (GIC) issue a certificate for the Project. There were 28 recommended conditions attached to the decision.
- Manitoba Hydro now awaits a decision on the approval of the issuance of a certificate by the GIC.
- Property acquisition is continuing and over 80% of the private land owners along the proposed transmission line route between Vivian, Manitoba and the U.S. Border have signed easement agreements.
- In order to secure the project in-service date Manitoba Hydro must move forward with long lead time items such as the material contracts prior to receiving Provincial and Federal regulatory approvals. Failure to do so would result in substantial project delays. Should Manitoba Hydro receive notification that the project will not receive its necessary regulatory approvals, materials may be re-used on future transmission projects in order to recover sunk costs.
- Tower steel began to arrive at the material storage yard in November and will continue to be delivered into January 2019.
- Regulatory approvals were not received in time to start construction in December 2018 as anticipated, therefore contractors who submitted proposals for the construction contracts were asked to update their pricing and plans for a later construction start date of June 2019. Contractors were asked to submit this information by December 19, 2018. Construction Contracts will not be awarded until receipt of regulatory approvals.
- The control budget will be reviewed later this year once regulatory approvals and conditions have been received, and construction start established.

MMTP Budget

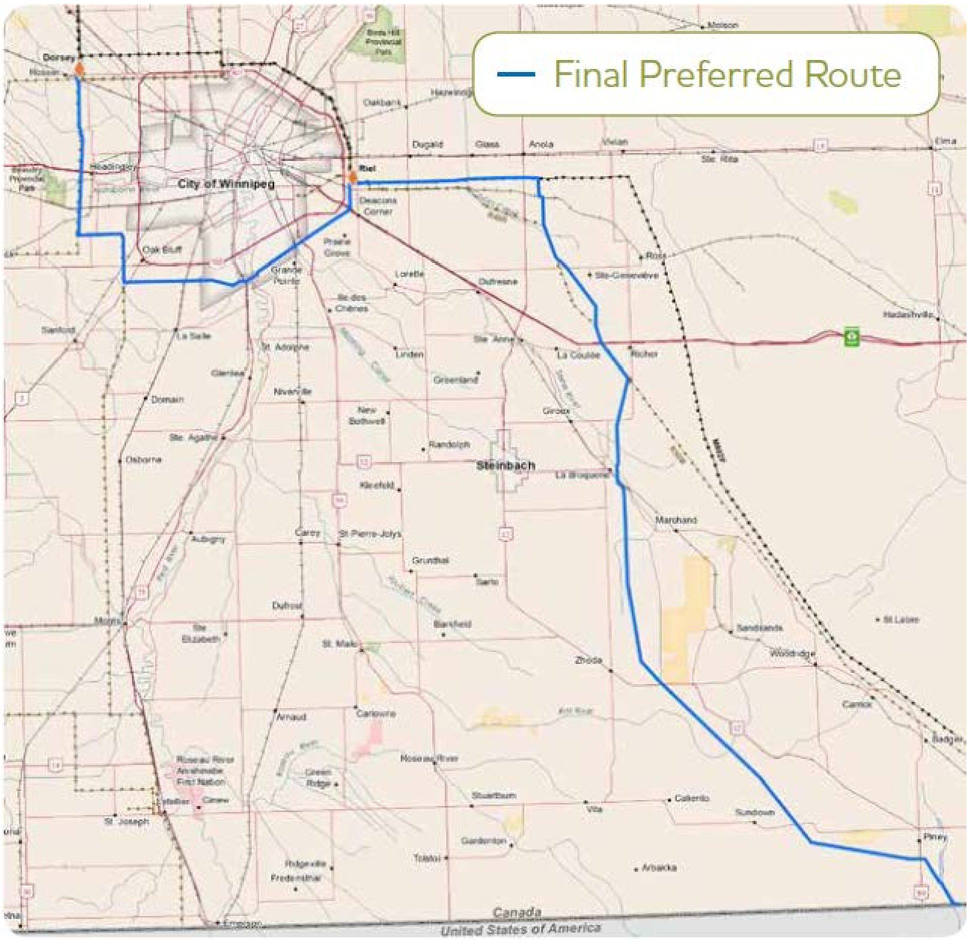
MMTP Budget Summary (in Millions $)			
Item #	**Item**	**Total Project Control Budget**	**Actual costs to Dec 31, 2018**
1.1	Licensing & Environmental	31.5	22.8
1.2	500 kV Transmission Line *	213.6	61.3
1.3	Station Upgrades*	112.8	24.6
1.4	Contingency	95.3	-
1.5	Total	453.2	108.7

*No construction contracts above $50 million are currently in place.

MMTP Project Schedule



MMTP Project Route



Birtle Project Description

Construction of the Manitoba portion of a new 230kV Transmission Line between Birtle, Manitoba and Tantallon, Saskatchewan is known as the Birtle Transmission Project. The Birtle transmission line (B71T) will originate at Birtle South Station and extend 46 km to the Manitoba-Saskatchewan border. The Birtle Transmission Project also includes upgrades to transmission line P52E as well as upgrades at Raven Lake, Virden West, and The Pas Ralls Island stations.

Birtle Project Update

- Manitoba Hydro filed the Environmental Act Proposal for the project on January 30, 2018. Manitoba Sustainable Development is continuing with the Section 35 consultation process. Manitoba Hydro gas been granted permission to conduct geotechnical drilling in advance of receipt of the Environmental License for this project, which aids in advancing completion of design and material procurement. As a result, Manitoba Hydro has explored options of advancing construction timelines for new the Birtle Transmission Line B71T, and determined construction may possibly be advanced, pending receipt of License as well as property and materials being procured as required.
- Material procurement for tubular steel towers is underway. Contract documents are currently being drafted; the tender is targeted to be posted on MERX in February, 2019.
- In order to secure the project in-service date Manitoba Hydro must move forward with long lead time items such as the material contracts prior to receiving Provincial regulatory approvals. Failure to do so would result in substantial project delays. Should Manitoba Hydro receive notification that the project will not receive its necessary regulatory approvals, materials may be re-used on future transmission projects in order to recover sunk costs.
- Manitoba Hydro has identified two relatively minor re-routes that will be required for the Birtle Transmission Line B71T.
- Land appraisals for easements required for B71T are continuing. Manitoba Hydro’s land agent started landowner discussions in December, 2018.
- Telecommunication design activities are continuing. Procurement of Optical Ground Wire (OPGW) conductor is underway, with tender award anticipated by January, 2019.
- Automation Control Engineering for Birtle South Station is expected to continue until June, 2019. Design of foundations and structures will be initiated in January, 2019. Construction at Birtle South Station is anticipated to start in the summer of 2019 pending receipt of the Environmental License for the project.
- The overall project budget is currently under review

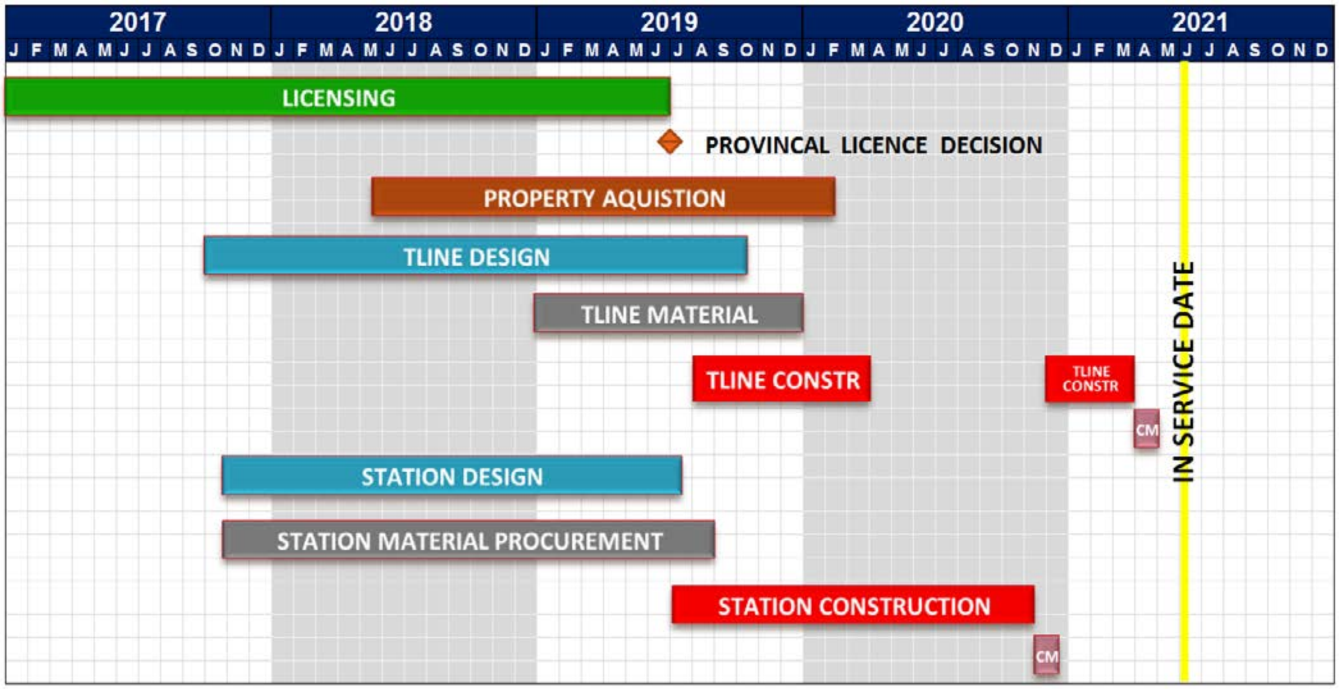
Birtle Budget

Birtle Budget Summary (in Millions $)			
Item #	**Item**	**Total Project Control Budget**	**Actual costs to Sept 30, 2018**
1.1	Licensing & Environmental	4.65	2.18
1.2	Transmission line[1]	43.83	0.68
1.3	Station Upgrades	7.94	0.44
1.4	**Total[1]**	**56.5**	**3.30**

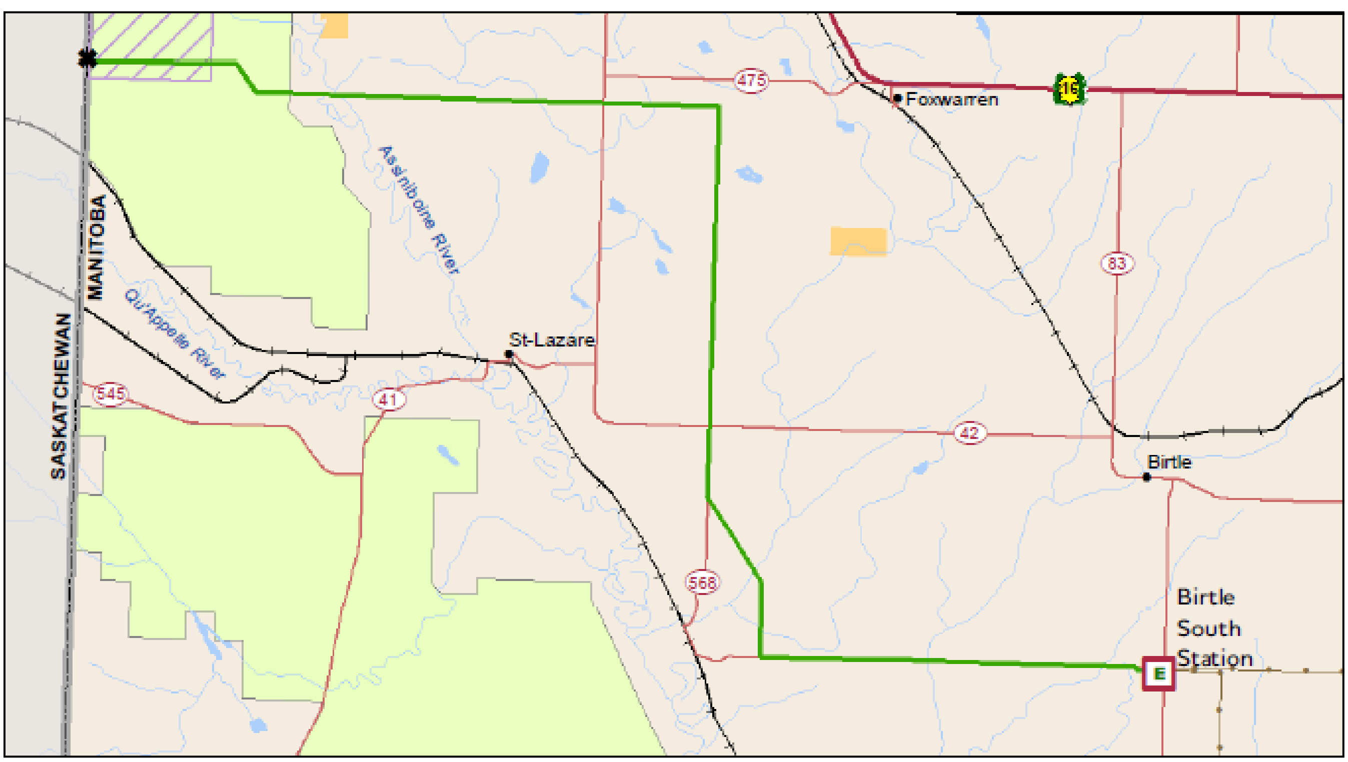
1. In the current control budget contingency is built into the project costs.

Note: there are no construction contracts or contracts above $50 million currently in place.

Birtle Project Schedule



Birtle Final Preferred Route Map



REFERENCE:

Appendix 7 Quarterly Major Capital Reports; 2017/18 GRA Transcript p. 5725

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Confirm whether the 10% across-the-board productivity improvement in the Keeyask project required to stay within the $8.7 billion control budget was achieved in the 2018 construction season. If not confirmed, explain how the actual productivity achieved will affect the schedule and final cost of the project.

b) Provide the forecast (per the General Civil Contract for 2016, per Amending Agreement 7 for 2017, and per the 2018 target for 2018) and actual productivities (in person-hours per cubic metre) for both concrete placement and earthworks for Keeyask in each of 2016, 2017, and 2018.

RESPONSE:

a) Entering the 2018 construction season, the project required at least a 10% improvement in General Civil Contract ("GCC") performance for the remainder of their work and no substantive risks to materialize to achieve the control budget of $8.7B. At the start of the year the first unit in-service date ("ISD") for Keeyask was trending 4 to 6 months ahead of the control schedule.

Schedule improvements achieved in 2018, predominantly by the GCC, have returned the project cost forecast in line with the $8.7B control budget. Since the start of 2018, the schedule has improved 4-6 months and the first unit ISD now trending 10 months ahead of the control schedule. There was no measurable improvement in the concrete productivity, although the work completed in 2018 was more complex. There was significant improvement in the earthworks productivity, and the chart below provides the data for comparison. Continued focus to manage costs is required. While the

Keeyask Project is currently trending to meet the control budget and schedule, there are still significant risks in the remaining 3 years of construction that could impact the cost and schedule of the project. The challenge for 2019 will be to continue to meet and exceed the project plan as the work becomes more complex and more coordination between various contractors and trades is required.

b) The following charts compare concrete and earthworks productivity values from the General Civil Contract and Amending Agreement 7 (AA7) to actual productivity rates experienced in 2016, 2017 and 2018. The 2018 target for concrete and earthworks productivity remains at the level stated in the AA7. Specific details regarding productivity rates are considered commercially sensitive information and as such have been redacted from the charts below.

[redacted]

1a + 8

[redacted] 1a + 8

REFERENCE:

2017/18 GRA Transcript p. 5581, 5725; Appendix 7 p.69, 75 of 81

PREAMBLE TO IR (IF ANY):

At the 2017/18 GRA, with respect to Keeyask, Manitoba Hydro stated:

Our top risk include successful execution of the general civil contract; loss of site access; work stoppages; unexpected geotechnical conditions. For example, we haven't uncovered the bedrock or the -- where the future south dam will be; and unseasonal weather.

Also:

We require a 10 percent improvement in our productivity for GCC and no major risk materialized to reach our control budget.

In Appendix 7 at page 75, it appears that the cofferdams have been constructed and the south channel dewatered, exposing the river bottom.

QUESTION:

a) Please confirm whether any of the major risks contemplated at the 2017/18 GRA have materialized. If confirmed, please explain the risk, the cost impact, and the mitigation measures Manitoba Hydro has implemented or intends to implement.
b) Please confirm whether the geological conditions at the location of the Keeyask South Dam have been fully ascertained such that Manitoba Hydro has made an assessment of whether the geotechnical risks in this area have been realized or avoided. If not, please state when such a determination is expected to be made.

RESPONSE:

a) No major risks materialized in 2018 that had a significant impact to the Keeyask Project. With 3 years of construction remaining; however, significant risk still remains.

An update on the major risks that were contemplated at the 2017/18 GRA are as follows. These risks continue for all or a portion of the remaining construction of the Keeyask Project.

1) **Execution of the General Civil Works Contractor (GCC)**
   See response to PUB/MH I-55a.

2) **Loss of site access/work stoppage due to a blockade or major safety/environmental incident.**
   No events occurred in 2018 that resulted in a loss of site access or work stoppage.

3) **Unseasonable weather that shortens the summer construction season.**
   Wet weather in September 2018 impacted earthwork activities such as the placement of impervious core of the earth structures. Mitigation measures were employed to modify the execution of the work to keep the work moving forward. These mitigation efforts were successful and production and productivity targets for earthworks were exceeded at the end of the 2018 construction season.

4) **Unknown geotechnical/geological conditions at the South Dam**
   See response to part b) below.

b) The geological risk related to the South Dam was that the bedrock conditions were unknown until the area was dewatered. The main risk was that the underlying bedrock conditions would require extensive mitigation that would cause a delay to the completion of the structure in 2019. Not completing the South Dam in 2019 would have a consequential impact of delaying river impoundment in 2020 and ultimately delaying the in-service date of the generating units.

   In July/August 2018 the South Dam Cofferdams were constructed and the natural course of the Nelson River was re-routed (diverted) through the Spillway structure. The area within the upstream and downstream cofferdams was dewatered and a majority of the area has been excavated to expose the underlying bedrock conditions, reducing the risk of the unknown. Portions of the bedrock encountered were at a lower elevation than anticipated which will require an adaptive treatment.

As the underlying bedrock conditions are now largely known, it is expected that with an early start in the spring and good weather throughout the summer, the South Dam will be completed in 2019, protecting the 2020 impoundment milestone.

Manitoba Hydro will have full clarity on the extent of the mitigation efforts required for the lower elevation of bedrock by May 2019. In the event that the execution of the mitigation measures delays the start of the South Dam construction, completion of the structure in 2019 could still be at risk.

REFERENCE:

Appendix 6 CEF18; Appendix 7

PREAMBLE TO IR (IF ANY):

CEF18 shows the capital cost of Bipole III as $5.04B. Appendix 7 page 65 of 81 indicates the revised capital cost is $4.77 billion.

QUESTION:

Confirm whether the revised capital cost of $4.77 billion is reflected in the 2018/19 Outlook and 2019/20 Interim Budget financial projections. If not confirmed, provide the changes in revenue requirement and cash flow that result in each year (2018/19 and 2019/20) due to the revised capital cost.

RESPONSE:

The revised capital cost of $4.77 billion was not reflected in the 2018/19 Outlook and the 2019/20 Interim Budget financial projections as it is pending final approval from the MHEB.

The attached tables provide the revenue requirement over the five year period from 2018/19 – 2022/23 assuming a $4.77 billion capital cost as compared to the $5.04 billion capital cost and the difference. The impact on the revenue requirement is higher in the first few years due to changes in cash flow timing assumptions. Once fully in-service, the difference is approximately $17 million per year due to the lower financing costs and depreciation expense.

BIPOLE III ($4.77B) & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	121	219	228	234	228
OM&A Costs	8	13	13	13	14
Depreciation	70	101	102	103	103
Amortization of BPIII Reserve	(59)	(78)	(78)	(78)	(78)
Capital Tax	22	22	23	23	23
	163	277	288	295	289

BIPOLE III ($5.04B) & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	133	240	243	246	240
OM&A Costs	8	13	13	13	14
Depreciation	77	108	107	106	106
Amortization of BPIII Reserve	(59)	(78)	(78)	(78)	(78)
Capital Tax	24	24	24	24	24
	184	307	309	312	306

IMPACT ON REVENUE REQUIREMENT
(In Millions of Dollars)

For the year ended March 31	2019	2020	2021	2022	2023
Finance Expense	(12)	(21)	(16)	(12)	(12)
OM&A Costs	-	-	-	-	-
Depreciation	(7)	(7)	(4)	(4)	(4)
Amortization of BPIII Reserve	-	-	-	-	-
Capital Tax	(2)	(2)	(1)	(1)	(1)
	(21)	(30)	(21)	(17)	(17)

REFERENCE:

Appendix 6 CEF18; Appendix 7

PREAMBLE TO IR (IF ANY):

CEF18 shows the capital cost of Bipole III as $5.04B. Appendix 7 page 65 of 81 indicates the revised capital cost is $4.77 billion.

QUESTION:

Confirm whether the revised capital cost of $4.77 billion is reflected in the 2018/19 Outlook and 2019/20 Interim Budget financial projections. If not confirmed, provide the changes in revenue requirement and cash flow that result in each year (2018/19 and 2019/20) due to the revised capital cost.

RESPONSE:

Please see the response to PUB/MH I-9 (Updated) for the updated revenue requirement for Bipole III over the five year period from 2018/19 – 2022/23 assuming a $4.77 billion capital cost as reflected in the 2019/20 Approved Budget, including the finance expense reflecting the update to Manitoba Hydro's average cost of debt.

Manitoba Hydro

REFERENCE:

Appendix 7 p. 63; CSI MNG&T Quarterly Report for July to September 2018; 2017/18 GRA Exhibit MGF-5

PREAMBLE TO IR (IF ANY):

The CSI MNG&T Quarterly Report for July to September 2018 identifies the Bipole III contingency including the original budget and allocated amounts.

QUESTION:

a) Identify the contracts and any materialized risks to which the allocated contingency shown in CSI Table B is applied.
b) Confirm whether and the amount of contingency applied to the Keewatinohk 230kV AC switchyard contract as contemplated by Amplitude Consultants in MGF-5 page 11.

RESPONSE:

a) The allocated contingency outlined in Table B of the CSI version of the MNG&T Quarterly Report for July to September 2018 was allocated as follows:

[redacted] 8a

[redacted] 8a

The [redacted] amount represented contingency for potential risks identified for each specific Contract. Contingency spent to address materialized risks is represented by the "Draw-down" amount shown in Table B. 8a

b) The Keewatinohk 230kV AC Switchyard Contract was completed at a value of [redacted]. No draw from unallocated contingency was required to complete the contract as contemplated by Amplitude Consultants in MGF-5 page 11. [redacted]. 8a 8a

REFERENCE:

Appendix 7 p. 77 of 81

PREAMBLE TO IR (IF ANY):

The National Energy Board decision with respect to the Manitoba-Minnesota Transmission Project was rendered November 15, 2018.

QUESTION:

a) Confirm whether Governor in Council approval for this project has been received and whether there are any remaining regulatory approvals required. If further approvals are required, indicate what the approvals relate to and when they are expected to be received.
b) Provide the dates when Manitoba Hydro expects to commence construction of the MMTP transmission line and station work.
c) Confirm whether Manitoba Hydro is proceeding with a new Request For Proposal process for a later construction start date. If confirmed, explain how such a later start date is expected to affect the project schedule, in-service date, final costs, and cash flow in 2019/20 compared to the cash flow included in the Interim Budget assumptions.
d) Appendix 6 CEF18 at page 16 shows the capital spending on MMTP increasing in 2018/19 by $47.7 million and in 2019/20 by $61.5 million. Confirm whether the increased spending in each of 2018/19 and 2019/20 will occur as shown in CEF18 considering the delay in commencing construction. If the spending will not be in the range indicated in the CEF18 for 2018/19 and 2019/20, indicate the expected impact on investing activities cash flow in each year.

RESPONSE:

a) On November 15th 2018 the National Energy Board ("NEB") issued a "Reasons for Decision" recommending that the Governor In Council (Federal Cabinet) approve the NEB's issuance of a certificate for the project along with recommended conditions. The Governor in Council decision for this project has not yet been received. As per Section 35 of *the Constitution Act,* Indigenous consultation is underway and must be completed prior to Governor In Council issuing a certificate. This certificate will likely be accompanied by additional conditions.

Manitoba Hydro is also awaiting a licensing decision from the province of Manitoba. Construction cannot begin until all Federal and Provincial approvals are in place and pre-construction conditions have been met.

b) Manitoba Hydro will commence construction once all approvals are in place and any associated conditions associated with those approvals have been met.

c) Manitoba Hydro is not proceeding with a new Request for Proposal process but rather will be proceeding with a request for updated pricing on the previously submitted Request for Proposals based on a later construction date. The project schedule will be condensed with an assumed start date of June 2019 (after necessary provincial and federal approvals have been granted) but the project in service date will remain the same. Final costs for the project are estimated to be greater as more work will be taking place during the summer months when access and biosecurity costs will be higher. At this time the updated pricing is still being reviewed so final award amounts have not been determined to reflect the increase in cost.

d) Spending will not occur as shown in CEF18 as the schedule for construction has changed from a December 2018 start to a June 2019 start. Manitoba Hydro will revise the budget for 2019/20 once the construction bids have been awarded in the spring 2019.

REFERENCE:

2017/18 GRA PUB MFR 49, Appendix 3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) A schedule detailing the breakdown of the balances of the component of capitalized costs (wages, overhead etc.) in Construction Work In Progress for each major Generation and Transmission project for 2017/18 consistent with the 2018 Annual Report

b) A continuity schedule detailing the total CWIP for 2017/18 through 2019/20 in the same level as (a).

RESPONSE:

a) Please see the table below for the breakdown of construction work in progress ("CWIP") for Major Generation and Transmission projects by capitalized components consistent with the 2018 Annual Report.

Breakdown of Major Generation and Transmission projects by capitalized cost components
As at March 31, 2018
(in millions of dollars)

	Activity Charges	Overhead	Interest	Material	Other	Total
Keeyask	218	25	615	54	3 589	4 501
Bipole III-Converter Stations	120	10	191	47	1 872	2 240
Bipole III - Transmission Line	97	10	150	227	1 069	1 552
Bipole III - Collector Lines	20	2	23	34	107	187
Bipole III-Community Develop Initiative	-	-	3	-	52	56
Manitoba-Minnesota Transmission Project	13	1	4	12	19	48
Gillam Redevelopment & Expansion Program	1	-	0	-	3	5
Birtle Transmission Project	1	0	0	-	1	3
Kettle Improvements & Upgrades	1	-	0	-	2	3
Major Generation and Transmission	470	48	987	373	6 716	8 594
Electric Business Operation Capital and Other						401
Total Electric Operations						8 995
Gas and Subsidiaries						4
Annual Report - Note 16						8 999

b) Please see below for the continuity schedule for the total CWIP for 2017/18 through 2019/20. The following assumptions have been used in preparing the schedule:

- Subsequent to 2017/18, expenditures pertaining to the Gillam Redevelopment & Expansion Program and the Kettle Improvements & Upgrades were reclassified to Business Operations Capital and are therefore excluded from the continuity.
- For the 2018/19 and 2019/20 period, amounts included in the schedule are based on the CEF18 forecast which incorporates the 2017/18 Outlook Closing CWIP amounts as the opening 2018/19 balances. Notably, the total net difference between the 2017/18 actual and Outlook ending CWIP balances is only $27 million or 0.3% of the $8 586 million total balance.
- For forecasting purposes, 100% of the Bipole III-Converter Station expenditures are assumed to be placed in-service in 2018/19 as only $23 million in expenditures remain to be incurred for the 2019/20 period.

ACTUALS TO 2017/18 *(in millions of dollars)*	Opening CWIP	Activity Charges	Overhead	Interest	Material	Other	Total Exp	In-Service	Closing CWIP	2017/18 Outlook Closing CWIP	Outlook vs Actual Variance
Keeyask	3 264	46	2	151	9	1 030	1 238	-	4 501	4 485	(16)
Bipole III-Converter Stations	1 643	33	1	89	7	469	598	1	2 240	2 263	23
Bipole III - Transmission Line	1 069	22	1	63	11	388	485	3	1 552	1 575	23
Bipole III - Collector Lines	165	4	0	9	4	13	30	8	187	188	1
Bipole III-Community Develop Initiative	53	-	-	1	-	1	3	-	56	56	(0)
Manitoba-Minnesota Transmission Project	22	5	0	2	11	9	27	-	48	44	(4)
Birtle Transmission Project	1	1	-	0	-	1	2	-	3	2	(1)
Major Generation and Transmission	**6 216**	**110**	**5**	**314**	**42**	**1 911**	**2 382**	**12**	**8 586**	**8 613**	**27**

2018/19 CEF18 FORECAST *(in millions of dollars)*	Opening CWIP	Activity Charges	Overhead	Interest	Material	Other	Total Exp	In-Service	Closing CWIP
Keeyask	4 485	58	2	199	5	1 001	1 265	-	5 750
Bipole III-Converter Stations	2 263	30	1	37	11	266	346	2 632	(23)
Bipole III - Transmission Line	1 575	3	0	25	1	257	287	1 862	(0)
Bipole III - Collector Lines	188	0	0	3	0	22	26	214	0
Bipole III-Community Develop Initiative	56	-	-	0	-	1	1	57	(0)
Manitoba-Minnesota Transmission Project	44	13	1	5	63	78	160	-	204
Birtle Transmission Project	2	1	0	0	1	0	2	-	4
Major Generation and Transmission	**8 613**	**106**	**4**	**270**	**81**	**1 625**	**2 087**	**4 764**	**5 936**

2019/20 CEF18 FORECAST *(in millions of dollars)*	Opening CWIP	Activity Charges	Overhead	Interest	Material	Other	Total Exp	In-Service	Closing CWIP
Keeyask	5 750	66	3	253	4	692	1 017	-	6 767
Bipole III-Converter Stations	(23)	6	0	-	-	17	23	1	(0)
Bipole III - Transmission Line	(0)	0	0	-	-	1	1	-	0
Bipole III - Collector Lines	0	-	-	-	-	-	-	-	0
Bipole III-Community Develop Initiative	(0)	-	-	-	-	-	-	-	(0)
Manitoba-Minnesota Transmission Project	204	16	1	13	21	90	142	-	346
Birtle Transmission Project	4	3	0	1	7	9	20	-	24
Major Generation and Transmission	**5 936**	**91**	**4**	**267**	**32**	**809**	**1 202**	**1**	**7 137**

0REFERENCE:

2017/18 GRA PUB MFR 49, Appendix 3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) A schedule detailing the breakdown of the balances of the component of capitalized costs (wages, overhead etc.) in Construction Work In Progress for each major Generation and Transmission project for 2017/18 consistent with the 2018 Annual Report
b) A continuity schedule detailing the total CWIP for 2017/18 through 2019/20 in the same level as (a).

RESPONSE:

a) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

b) Please see below for the continuity schedule for the total CWIP for 2017/18 through 2019/20. The following assumptions have been used in preparing the schedule:
   - Subsequent to 2017/18, expenditures pertaining to the Gillam Redevelopment & Expansion Program and the Kettle Improvements & Upgrades were reclassified to Business Operations Capital and are therefore excluded from the continuity.
   - For the 2018/19 and 2019/20 period, amounts included in the schedule are based on the 2018/19 Current Outlook and the 2019/20 Approved Budget as per the Supplement to the 2019/20 Electric Rate Application.

ACTUALS TO 2017/18 (in millions of dollars)	Opening CWIP	Activity Charges	Overhead	Interest	Material	Other	Total Exp	In-Service	Closing CWIP
Keeyask	3 264	46	2	151	9	1 030	1 238	-	4 501
Bipole III-Converter Stations	1 643	33	1	89	7	469	598	1	2 240
Bipole III - Transmission Line	1 069	22	1	63	11	388	485	3	1 552
Bipole III - Collector Lines	165	4	0	9	4	13	30	8	187
Bipole III-Community Develop Initiative	53	-	-	1	-	1	3	-	56
Manitoba-Minnesota Transmission Project	22	5	0	2	11	9	27	-	48
Birtle Transmission Project	1	1	-	0	-	1	2	-	3
Major Generation and Transmission	**6 216**	**110**	**5**	**314**	**42**	**1 911**	**2 382**	**12**	**8 586**

SUPPLEMENT TO THE ELECTRIC RATE APPLICATION 2018/19 CURRENT OUTLOOK (in millions of dollars)	Opening CWIP	Activity Charges	Overhead	Interest	Material	Other	Total Exp	In-Service	Closing CWIP
Keeyask	4 501	56	2	200	9	1 036	1 304	-	5 805
Bipole III-Converter Stations	2 240	18	1	27	3	122	171	2 409	2
Bipole III - Transmission Line	1 552	7	0	19	(1)	40	65	1 617	(0)
Bipole III - Collector Lines	187	1	0	2	1	2	6	193	(0)
Bipole III-Community Develop Initiative	56	-	-	0	-	0	1	56	0
Manitoba-Minnesota Transmission Project	48	9	0	3	51	11	75	7	117
Birtle Transmission Project	3	1	0	0	0	0	2	-	5
Major Generation and Transmission	**8 586**	**91**	**4**	**253**	**64**	**1 213**	**1 624**	**4 282**	**6 243**

SUPPLEMENT TO THE ELECTRIC RATE APPLICATION 2019/20 APPROVED BUDGET (in millions of dollars)	Opening CWIP	Activity Charges	Overhead	Interest	Material	Other	Total Exp	In-Service	Closing CWIP
Keeyask	5 805	65	3	253	3	795	1 119	-	6 924
Bipole III-Converter Stations	2	2	0	-	2	69	74	76	(0)
Bipole III - Transmission Line	(0)	1	0	0	6	8	15	15	(0)
Bipole III - Collector Lines	(0)	0	0	-	0	2	2	2	(0)
Bipole III-Community Develop Initiative	0	-	-	-	-	-	-	-	0
Manitoba-Minnesota Transmission Project	117	25	1	11	35	200	272	2	387
Birtle Transmission Project	5	4	0	1	8	12	24	-	29
Major Generation and Transmission	**5 928**	**97**	**4**	**265**	**54**	**1 086**	**1 506**	**95**	**7 339**

REFERENCE:

2017/18 GRA PUB/MH II-88; Compliance Filing to Order 59/18 pg. 2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide an update of PUB/MH II-88(b) with: June 1, 2018 consumer rates, updated Bipole III revenue requirement, and deducting net export revenues from the class costs (as opposed to adding net export revenues to class revenues). Provide the charts with rate differentiation to move the Revenue to Cost Coverage ratios of all classes within the zone of reasonableness in 1, 5, and 9 years. Present versions with and without the requested 3.5% rate increase and show the indicated rate increases to two decimal places. Identify any limitations or concerns with the resulting RCCs and rate differentiation.

RESPONSE:

Manitoba Hydro modified the methodology used in PCOSS18, in order to reflect the directives arising from Order 59/18 identified as in scope in Order 1/19 as follows:

- The alternate Revenue to Cost Coverage ("RCC") ratio methodology was used (Directives 5 & 27). In the alternate RCC calculation Net Export Revenue is treated as a reduction of class cost, rather than as an addition to class revenue.
- Non tariffable transmission was excluded from the allocation of Net Export Revenue (Directive 24). This resulted in an increase of $2.6 million in net Transmission costs, with an offsetting $2.6 million reduction in net Generation costs.
- A new subfunction was added to allocate the specified customer service costs to all classes other than GSL 30-100kV and GSL >100kV (Directive 25). The revised allocation results in a decrease in net costs of $0.6 million for GSL 30-100kV and $1.5 million for GSL >100kV.

Figure 1 provides the RCC impacts of each change, as well as the revised PCOSS18 results incorporating all methodology changes.

Figure 1

	PCOSS18	Directives 5 & 27	Directive 24	Directive 25	PCOSS18 59/18
Residential	94.8%	-1.3%	0.0%	-0.1%	93.4%
GSS ND	112.5%	3.2%	0.0%	-0.2%	115.5%
GSS D	101.0%	0.3%	0.0%	-0.2%	101.1%
GSM	98.3%	-0.5%	0.0%	-0.1%	97.7%
GSL 0-30	99.1%	-0.4%	0.1%	-0.2%	98.6%
GSL 30-100	109.3%	3.7%	0.1%	1.1%	114.2%
GSL >100	108.6%	3.7%	0.1%	1.0%	113.4%
Area & Roadway Lighting	100.3%	0.0%	0.0%	-0.2%	100.1%

To provide a high level indication of the anticipated shift in functionalized costs and revenue cost coverage ratios in 2019/20 with Bipole III in-service, the following assumptions have been made:

- Bipole III costs based on revised capital cost of $4.77 billion.
- The estimated $334 million carrying and operating costs of Bipole III has been functionalized as Generation. These costs exclude the costs of the Riel 230/500 kV AC station that were already included in PCOSS18 Transmission costs.
- The residual increase in revenue requirement, which was not specifically attributed to Bipole III, is assumed related to existing assets and has been functionalized by cost category in proportion to the PCOSS18 revenue requirement.
- The $78 million funding provided by amortization of the Bipole III Reserve Account has been distributed proportionally based on class revenues, consistent with PUB findings on page 190 of Order 59/18.
- Since PCOSS18 reflects domestic revenues based on August 1, 2016 rates, class revenues were first revised to include the June 1, 2018 differentiated rate increases and then adjusted on an across-the-board basis in order to offset the remaining increase in forecast revenue.

Updating the PCOSS to incorporate the Biopole III revenue requirement increases the Generation related portion of revenue requirement from 55 to 63%. This asymmetrical increase in costs by function will have a larger impact on classes that use relatively more, or less, Generation than average. For example 88% of the cost of serving General Service Large >100kV are Generation related, compared to only 18% of the costs of serving Area and Roadway Lighting. As a result the addition of Bipole III significantly decreases the revenue cost coverage ratio of the GSL class, while significantly increasing that of Area and Roadway Lighting. There are less pronounced RCC impacts for classes such as General Service Medium that have functional cost proportions closer to the system average.

The tables below provides the annual rate differentiation required to move all classes into the zone of reasonableness (95-105%), while maintaining overall revenue neutrality, over 1, 5 and 9 years. The revenue shortfall that results from the below average rate changes for the GSS ND and A&RL classes is assumed to be recovered from all classes below unity, and is distributed between the Residential, First Nations On-Reserve, GSM and GSL 0-30 kV classes such that the final RCC for all four is equivalent.

The initial class revenue cost coverage ratios in Figure 2 reflect the previously discussed methodology changes, as well as the Bipole III related adjustments to revenue requirement.

Figure 2: At June 1, 2018 Rates

	Initial RCC including BPIII	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 9 Years	Final RCC
Residential	96.5%	1.85%	0.37%	0.20%	98.3%
First Nations On-Reserve	93.1%	5.61%	1.10%	0.61%	98.3%
GSS ND	116.7%	-10.02%	-2.09%	-1.17%	105.0%
GSS D	101.8%	0.00%	0.00%	0.00%	101.8%
GSM	97.5%	0.85%	0.17%	0.09%	98.3%
GSL 0-30	96.1%	2.27%	0.45%	0.25%	98.3%
GSL 30-100	104.6%	0.00%	0.00%	0.00%	104.6%
GSL >100	101.9%	0.00%	0.00%	0.00%	101.9%
Area & Roadway Lighting	118.7%	-11.56%	-2.43%	-1.36%	105.0%

The initial class revenue cost coverage ratios in Figure 3 are based on revenues that incorporate the 3.5% rate increase requested in the current application on an across-the-board basis, in addition to the previously noted methodology and revenue requirement changes.

Figure 3: Including Requested 3.5% Rate Increase

	Initial RCC including BPIII and Requested 3.5%	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 9 Years	Final RCC
Residential	96.5%	1.83%	0.36%	0.20%	98.3%
First Nations On-Reserve	93.1%	5.60%	1.09%	0.61%	98.3%
GSS ND	116.7%	-10.06%	-2.10%	-1.17%	105.0%
GSS D	101.8%	0.00%	0.00%	0.00%	101.8%
GSM	97.4%	0.93%	0.18%	0.10%	98.3%
GSL 0-30	96.1%	2.32%	0.46%	0.26%	98.3%
GSL 30-100	104.6%	0.00%	0.00%	0.00%	104.6%
GSL >100	101.9%	0.00%	0.00%	0.00%	101.9%
Area & Roadway Lighting	119.1%	-11.81%	-2.48%	-1.39%	105.0%

The RCCs shown for the First Nations On-Reserve class are high level estimates that are intended to reflect the RCC impact of the June 1, 2018 rate freeze. Manitoba Hydro has not been able to modify PCOSS18 to fully incorporate the new First Nations On-Reserve class due to the absence of class specific load research and customer weighting factors. In absence of updated costs profiles the new class has been attributed 7% of total Residential costs, which is consistent with the class's share of total Residential class revenues prior to the rate freeze. The approach likely overstates the RCC of the First Nations On-Reserve class, as the class consists largely of electric heating customers that have a higher cost-to-serve than standard customers. The approach will also somewhat understate the RCC for the revised Residential class, which now contains relatively fewer electric heating customers.

REFERENCE:

2017/18 GRA PUB/MH II-88; Compliance Filing to Order 59/18 pg. 2

PREAMBLE TO IR (IF ANY):

QUESTION:

b) In order to move the General Service Small – Non-Demand class RCC towards the zone of reasonableness as directed in Order 59/18 Directive 5, Manitoba Hydro adjusted the energy, demand, and basic charge components of the rates in order to maintain commonality with the General Service Small – Demand and General Service Medium rates.

Provide indicative energy, demand, and basic charge rates reflecting the assumed "end goal" of having the GSS-ND class RCC within the zone of reasonableness. In preparing this response, use the update of PUB/MH II-88 provided in the response to (a) of this information request. Does Manitoba Hydro have any concerns with the resulting energy, demand, or basic charge rates?

In Manitoba Hydro's view, will it be feasible to maintain harmonized rates among the GSS and GSM classes? If not, identify potential courses of action to achieve the goal of having all classes' RCCs within the zone of reasonableness.

RESPONSE:

Achieving the targeted revenue requirement for the Small Non-Demand, Small Demand and Medium Demand customer classes requires a delicate balancing act when setting blocked energy rates for these customers. The three groups represent very diverse load characteristics, as indicated by the percentage of kW.h consumed in each block shown in the table below.

	General Service Small Non-Demand	General Service Small Demand	General Service Medium
First 11,000 kW.h	91%	43%	9%
Next 8,500 kW.h	9%	23%	7%
Balance		35%	85%

Amounts may not add due to rounding

As this table indicates, increasing or decreasing the first block energy rate will have a significant impact on the revenue received from Small Non-Demand customers, but will have considerably less impact on Small Demand and Medium Demand customers. Conversely, increasing the tail block rate would have no impact on Small Non-Demand customers but will greatly impact the Small Demand and Medium Demand customers.

Two other important considerations when determining the blocked energy rates for these customers is the role the Basic Charge and Demand Charge play on each subclass. The majority of customers are Small Non-Demand, hence increasing the Basic Charge, even minimally, will generate more revenue from this group of customers than the other two groups. With respect to Demand Charges, Small Non-Demand customers do not pay a Demand Charge; therefore the first block energy rate is higher to compensate for this. Medium customers, on the other hand, generate roughly 34% of their total revenue from demand charges, much higher than the 18% demand revenue received from Small Demand customers. The tail block energy rate is therefore lower to account for this.

The substantial differences in RCC between GSS ND (116.7), GSS Demand (101.8) and GSM (97.5) as shown in Figure 2 in the response to PUB/MH I – 61a poses a significant challenge in accomplishing the goal of moving the GSS ND class into the ZOR under a harmonized rate structure. While dramatic changes to the rate components could provide a means of attaining the overall desired revenue in order to have RCCs fall within the ZOR (such as elimination of the basic monthly charge and substantial increase to the 2nd block energy rate), the resulting rates would not yield price signals that are aligned with cost causation and the outputs of the Cost of Service study. As an example, based on cost causation it could be argued that the current basic monthly charge, which reflects the fact that significant customer-related costs are incurred in providing GSS and GSM customers with access to the Manitoba Hydro system regardless of the level of energy consumed for each customer, should be increased for all three customer classes, as opposed to eliminated.

In Manitoba Hydro’s view it is not appropriate to propose the magnitude of rate rebalancing required to achieve the RCC goals in advance of a more thorough analysis of class cost characteristics, load profiles and bill frequencies that would allow Manitoba Hydro to evaluate other rate design options.

REFERENCE:

2017/18 GRA PUB/MH I-3a; Application pg. 1 and 2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For the years 1999/00 through the test years, provide details of rate increases requested and approved, the annual revenue increase prevailing Manitoba CPI, cumulative additional annualized revenue for approved rate increases, percent of total revenue from domestic (actual and forecast), and electric debt to equity ratio (actual and forecast).

RESPONSE:

Please see the table below.

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI (fiscal)	Fiscal Yr Revenue Increases	Annual Increase in Revenue ($millions)	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue from Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Electric Operations Debt to Equity Ratio
1999/00	0%	-	2.2%	$0.00	$0.00	0.00%	2.20%	$0.0	66%	83:17
2000/01	0%	-	2.5%	$0.00	$0.00	0.00%	4.76%	$0.0	62%	80:20
2001/02 *	-1.92% Nov 1/01	-	2.1%	($6.00)	($14.40)	-1.92%	6.95%	-$14.4	57%	78:22
2002/03	0%	-	2.3%	$0.00	$0.00	-1.92%	9.41%	-$14.4	65%	81:19
2003/04	0% Apr 1/03	-0.72% Apr 1/03	0.9%	($6.50)	($6.50)	-2.63%	10.40%	-$20.9	72%	87:13
2004/05	3% Apr 1/04	5% Aug 1/04	2.7%	$32.30	$45.90	2.24%	13.38%	$25.0	63%	85:15
2005/06	2.5% Apr 1/05	2.25% Apr 1/05	2.4%	$21.80	$21.80	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 est	$23.10	6.90%	18.42%	$69.9	66%	80:20
2007/08	0% Apr 1/07	-	1.9%	$0.00	$0.00	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 est	$52.40	12.24%	23.33%	$122.3	68%	77:23
2009/10	3.9% Apr 1/09	2.84% Apr 1/09	0.6%	$32.80	$32.80	15.43%	24.07%	$155.1	75%	72:28
2010/11	2.9% Apr 1/10	2.8% Apr 1/10	1.0%	$32.90	$32.90	18.66%	25.31%	$188.0	77%	72:28
2011/12	2.9% Apr 1/11	2.0% Apr 1/11	2.8%	$24.40	$24.40	21.03%	28.82%	$212.4	78%	74:26
2012/13	3.5% Apr 1/12	2.0% Apr 1/12	1.6%	$25.80	$25.80	23.45%	30.88%	$238.2	80%	75:25
2012/13	2.5% Sep 1/12	2.4% Sep 1/12	1.6%	$19.40	$31.00	26.42%	30.88%	$269.2	-	75:25
2013/14	3.5% Apr 1/13	3.5% May 1/13	2.4%	$43.40	$47.60	30.84%	34.02%	$316.8	78%	77:23
2014/15	3.95% Apr 1/14	2.75% May 1/14	1.5%	$35.60	$38.70	34.44%	36.03%	$355.5	79%	83:17
2015/16	3.95% Apr 1/15	3.95% August 1/15	1.3%	$40.10	$57.40	39.75%	37.80%	$412.9	77%	84:16
2016/17	3.95% Apr 1/16	3.36% August 1/16	1.4%	$36.30	$52.30	44.44%	39.73%	$465.2	76%	85:15
2017/18	7.9% Aug 1/17	3.36% August 1, 2017	1.7%	$37.30	$52.40	49.30%	42.52%	$517.6	77%	86:14
2018/19	7.9% Apr 1/18	3.6% June 1, 2018	2.1%**	$49.60	$58.20	54.67%	45.52%	$575.8	81%	87:13**
2019/20	3.5% Apr 1/19 prop		2.0%**	$58.80	$58.80	60.09%	48.43%	$634.6	82%	87:13**

* This was the result of Uniform Rate Legislation, not a request made by Manitoba Hydro.

** Forecast

REFERENCE:

2017/18 GRA PUB/MH I-3a; Application pg. 1 and 2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For the years 1999/00 through the test years, provide details of rate increases requested and approved, the annual revenue increase prevailing Manitoba CPI, cumulative additional annualized revenue for approved rate increases, percent of total revenue from domestic (actual and forecast), and electric debt to equity ratio (actual and forecast).

RESPONSE:

Please see the table below.

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI (fiscal)	Fiscal Yr Revenue Increases ($millions)	Annual Increase in Revenue ($millions)	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue from Rate Increases ($millions)	% of Total Revenue from Domestic (Actual)	Actual Electric Operations Debt to Equity Ratio
1999/00	0%	-	2.2%	$0.00	$0.00	0.00%	2.20%	$0.0	66%	83:17
2000/01	0%	-	2.5%	$0.00	$0.00	0.00%	4.76%	$0.0	62%	80:20
2001/02 *	-1.92% Nov 1/01	-	2.1%	($6.00)	($14.40)	-1.92%	6.95%	-$14.4	57%	78:22
2002/03	0%	-	2.3%	$0.00	$0.00	-1.92%	9.41%	-$14.4	65%	81:19
2003/04	0% Apr 1/03	-0.72% Apr 1/03	0.9%	($6.50)	($6.50)	-2.63%	10.40%	-$20.9	72%	87:13
2004/05	3% Apr 1/04	5% Aug 1/04	2.7%	$32.30	$45.90	2.24%	13.38%	$25.0	63%	85:15
2005/06	2.5% Apr 1/05	2.25% Apr 1/05	2.4%	$21.80	$21.80	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 est	$23.10	6.90%	18.42%	$69.9	66%	80:20
2007/08	0% Apr 1/07	-	1.9%	$0.00	$0.00	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 est	$52.40	12.24%	23.33%	$122.3	68%	77:23
2009/10	3.9% Apr 1/09	2.84% Apr 1/09	0.6%	$32.80	$32.80	15.43%	24.07%	$155.1	75%	72:28
2010/11	2.9% Apr 1/10	2.8% Apr 1/10	1.0%	$32.90	$32.90	18.66%	25.31%	$188.0	77%	72:28
2011/12	2.9% Apr 1/11	2.0% Apr 1/11	2.8%	$24.40	$24.40	21.03%	28.82%	$212.4	78%	74:26
2012/13	3.5% Apr 1/12	2.0% Apr 1/12	1.6%	$25.80	$25.80	23.45%	30.88%	$238.2	80%	75:25
2012/13	2.5% Sep 1/12	2.4% Sep 1/12	1.6%	$19.40	$31.00	26.42%	30.88%	$269.2	-	75:25
2013/14	3.5% Apr 1/13	3.5% May 1/13	2.4%	$43.40	$47.60	30.84%	34.02%	$316.8	78%	77:23
2014/15	3.95% Apr 1/14	2.75% May 1/14	1.5%	$35.60	$38.70	34.44%	36.03%	$355.5	79%	83:17
2015/16	3.95% Apr 1/15	3.95% August 1/15	1.3%	$40.10	$57.40	39.75%	37.80%	$412.9	77%	84:16
2016/17	3.95% Apr 1/16	3.36% August 1/16	1.4%	$36.30	$52.30	44.44%	39.73%	$465.2	76%	85:15
2017/18	7.9% Aug 1/17	3.36% August 1/17	1.7%	$37.30	$52.40	49.30%	42.52%	$517.6	77%	86:14
2018/19	7.9% Apr 1/18	3.6% June 1/18	2.1%**	$49.60	$58.20	54.67%	45.52%	$575.8	81%	86:14**
2019/20	3.5% Jun 1/19 proposed		2.0%**	$49.90	$59.50	60.09%	48.43%	$635.3	82%**	87:13**

* This was the result of Uniform Rate Legislation, not a request made by Manitoba Hydro.

** Forecast

REFERENCE:

2017/18 GRA PUB/MH I-3a; Application pg. 1 and 2

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Provide the net present value of the proposed annualized revenue rate increase of 3.5%. Utilize Manitoba Hydro's weighted average cost to capital.
c) Provide the rate increase required to provide Manitoba Hydro with the same net income for 2019/20 if the rate increase is not implemented until May 1, 2019.
d) Provide the rate increase required to provide Manitoba Hydro with the same net income for 2019/20 if the rate increase is not implemented until June 1, 2019?
e) Provide the amount of foregone revenue if the requested 3.5% rate increase is implemented on May 1, 2019 instead of April 1, 2019.
f) Provide the amount of foregone revenue if the requested 3.5% rate increase is implemented on June 1, 2019 instead of April 1, 2019.
g) Provide the amount of foregone revenue if the requested 3.5% rate increase is implemented on July 1, 2019, instead of April 1, 2019.

RESPONSE:

b) The present value of the proposed annualized revenue associated with the proposed rate increase of 3.5% is $618 million (at 6.00% nominal WACC discount rate).

In Millions of Dollars

	Nominal WACC	Discount Factor	Annual Rate Increases	Effective Cumulative Rate Increases	Additional Domestic Revenue	Discounted Additional Domestic Revenue
2019	6.00%	1.000	0.00%	0.00%	$0	$0
2020	6.00%	1.060	3.50%	3.50%	59	55
2021	6.00%	1.124	0.00%	3.50%	58	52
2022	6.00%	1.191	0.00%	3.50%	58	49
2023	6.00%	1.262	0.00%	3.50%	58	46
2024	6.00%	1.338	0.00%	3.50%	57	43
2025	6.00%	1.419	0.00%	3.50%	57	40
2026	6.00%	1.504	0.00%	3.50%	57	38
2027	6.00%	1.594	0.00%	3.50%	57	36
2028	6.00%	1.689	0.00%	3.50%	58	34
2029	6.00%	1.791	0.00%	3.50%	58	33
2030	6.00%	1.898	0.00%	3.50%	59	31
2031	6.00%	2.012	0.00%	3.50%	60	30
2032	6.00%	2.133	0.00%	3.50%	61	28
2033	6.00%	2.261	0.00%	3.50%	62	27
2034	6.00%	2.397	0.00%	3.50%	63	26
2035	6.00%	2.540	0.00%	3.50%	64	25
2036	6.00%	2.693	0.00%	3.50%	65	24
NPV						**$618**

c) Manitoba Hydro would require a 3.84% rate increase on May 1, 2019 to achieve the same net income for 2019/20.

d) Manitoba Hydro would require a 4.18% rate increase on June 1, 2019 to achieve the same net income for 2019/20.

e) Implementing the 3.5% rate increase on May 1, 2019 instead of April 1, 2019 would decrease revenues by approximately $5 million in 2019/20.

f) Implementing the 3.5% rate increase on June 1, 2019 instead of April 1, 2019 would decrease revenues by approximately $9 million in 2019/20.

g) Implementing the 3.5% rate increase on July 1, 2019 instead of April 1, 2019 would decrease revenues by approximately $13 million in 2019/20.

REFERENCE:

Application pg. 33

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Indicate the actual foregone revenue from the First Nations On Reserve Residential and Diesel Residential customer classes for the 2018/19 fiscal year compared to the revenue that would have been received if the customer class and 0% rate increase had not been implemented.
b) Indicate the foregone revenue for the First Nations On-Reserve Residential and Diesel Residential customer classes for the 2019/20 test year resulting from the June 1, 2018 0% rate increase.
c) Indicate the foregone revenue for the First Nations On-Reserve Residential and Diesel Residential customer classes for the test year if this customer class does not receive a rate increase in the test year. Indicate the foregone revenue due to the June 1, 2018 0% rate increase as well as the foregone revenue due to an April 1, 2019 0% rate increase.
d) What is the rate impact to the other customer classes to keep Manitoba Hydro revenue neutral for each of items (a), (b), and (c).
e) What is the bill impact to the Residential Basic customer class to keep Manitoba Hydro revenue neutral for each of items (a), (b), and (c).

RESPONSE:

a) The actual foregone revenue from the First Nations on Reserve Residential and Diesel Residential customer classes for the 2018/19 fiscal year on account of receiving a 0% rate increase effective June 1, 2018 is as follows:

2018/19 YTD Actual (Jun-Nov 2018)	$588,000
Forecast (Dec 2018 - Mar 2019)	$846,000
Total	$1,434,000

b) The foregone revenue from the First Nations on Reserve Residential and Diesel Residential customer classes for the 2019/20 fiscal year resulting from a 0% rate increase effective June 1, 2018 is estimated to be $1.9 million.

c) An additional $1.7 million in revenue would be foregone if there is a 0% increase for First Nations Residential on Reserve and Diesel Residential customer classes in 2019/20. The cumulative effect of a 0% rate increase on June 1, 2018 as well as a 0% rate increase on April 1, 2019 is foregone revenue of approximately $3.6 million.

d) To maintain revenue neutrality on account of the 0% increase on June 1, 2018 to First Nations on Reserve Residential and Diesel Residential customer classes, all other customer classes received an additional 0.13% increase in the 2018/19 fiscal year. If there is no rate increase for First Nations on Reserve Residential and Diesel Residential customer classes in fiscal 2019/20, all other classes would need an additional 0.10% increase. The cumulative rate impact to maintain revenue neutrality as a result of no rate increase to the First Nation on Reserve Residential and Diesel Residential customer classes in 2018/19 and 2019/20 is an additional 0.22% increase to the other customer classes.

e) The bill impacts to the Residential Basic customer class to maintain revenue neutrality are as follows:

a) To maintain revenue neutrality arising from the 0% increase granted in 2018/19 to the First Nations On-Reserve Residential customer class ("FNOR"), the Residential impact in 2018/19 is as follows:

kWh	June 1, 2018 Bill if FNOR not implemented on June 1, 2018 $ / Month	June Approved Residential Bill $ / Month	Difference in $ / Month	Percent Change
250	$29.69	$29.73	$0.04	0.13%
750	$72.27	$72.36	$0.09	0.12%
1 000	$93.56	$93.68	$0.12	0.13%
2 000	$178.73	$178.95	$0.22	0.13%
5 000	$434.22	$434.76	$0.54	0.13%

b) To maintain revenue neutrality arising from the 0% increase granted in 2018/19 to the First Nations On-Reserve Residential customer class ("FNOR"), the Residential impact in 2019/20 is as follows:

kWh	April 1, 2019 Bill if FNOR not implemented in June 1, 2018 $ / Month	April 11, 2019 Proposed Residential Bill $ / Month	Difference in $ / Month	Percent Change
250	$30.74	$30.78	$0.04	0.13%
750	$74.82	$74.91	$0.10	0.13%
1 000	$96.85	$96.98	$0.13	0.13%
2 000	$185.01	$185.25	$0.24	0.13%
5 000	$449.48	$450.06	$0.58	0.13%

c) 1) To maintain revenue neutrality if no increase for First Nations On-Reserve Residential class ("FNOR") in 2019/20, the Residential impact in 2019/20 is as follows:

kWh	April 1, 2019 Proposed Residential Bill $ / Month	April 1, 2019 Residential Bill if no increase to FNOR and Diesel Residential in 18/19 & 19/20 $ / Month	Difference in $ / Month	Percent Change
250	$30.78	$30.81	$0.03	0.10%
750	$74.91	$74.98	$0.07	0.10%
1 000	$96.98	$97.07	$0.09	0.10%
2 000	$185.25	$185.43	$0.18	0.10%
5 000	$450.06	$450.49	$0.43	0.10%

c) 2) Total Residential impact arising from a 0% rate increase in 2018/19 and a 0% rate increase in 2019/20 to the First Nations On-Reserve Residential and Diesel Residential customer classes ("FNOR") is as follows:

kWh	April 1, 2019 Bill if FNOR not implemented on June 1, 2018 $ / Month	April 1, 2019 Residential Bill if no increase to FNOR and Diesel Residential in 18/19 & 19/20 $ / Month	Difference in $ / Month	Percent Change
250	$30.74	$30.81	$0.07	0.23%
750	$74.82	$74.98	$0.17	0.23%
1 000	$96.85	$97.07	$0.22	0.23%
2 000	$185.01	$185.43	$0.42	0.23%
5 000	$449.48	$450.49	$1.02	0.23%

REFERENCE:

Application Appendix 10, Appendix 12; 2017/18 GRA PUB/MH I-135

PREAMBLE TO IR (IF ANY):

QUESTION:

Provide the models and data used to prepare the forecast Proofs of Revenue and customer bill impacts in a similar format as PUB/MH I-135 from the 2017/18 GRA. Provide all work papers in Excel format.

RESPONSE:

Please see the Microsoft Excel document titled “PUB-MH I-64 Attachment” (tab 64 Att1a) for the spreadsheet model containing the forecast data (customer, energy and demand) and the calculation of revenues for Residential and General Service customer classes under June 1, 2018 approved and April 1, 2019 proposed rates. The revenues shown for 2019/20 correspond to Appendix 10 Proof of Revenue.

Please see the Microsoft Excel document titled “PUB-MH I-64 Attachment” (tab 64 Att1b) which provides the bill impact calculations for the Residential and General Service rate classes for the June 1, 2018 approved and April 1, 2019 proposed rates which correspond to Appendix 12 Bill Comparisons.