MANITOBA PUBLIC UTILITIES BOARD

MANITOBA HYDRO'S

2017/18 & 2018/19

GENERAL RATE APPLICATION

EVIDENCE PREPARED BY

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FOR

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&

WINNIPEG HARVEST

(THE CONSUMERS COALITION)

OCTOBER 31, 2017

Contents

1. INTRODUCTION

On May 5, 2017 Manitoba Hydro filed an Application with the Public Utilities Board of Manitoba ("PUB" or "Board") requesting a number of approvals[1] including:

i. Final Approval of Order 59/16 which approved, on an interim basis, an across the board rate increase of 3.36% effective August 1, 2016.

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

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

iv. Endorsement of the proposed deferral and subsequent amortization of costs incurred with respect to the Conawapa Generating project.

v. Endorsement of the proposed amortization period of the regulatory deferral accounts established to capture the differences between Depreciation Expense and Operating & Administrative Expense calculated for financial reporting purposes based on International Financial Reporting Standards ("IFRS") and Depreciation Expense and Operating & Administrative Expense calculated for rate setting purposes reflecting PUB directives in Order 73/15.

The PUB subsequently initiated a proceeding to review the Manitoba Hydro Application.

With respect to the requested interim rate increase of 7.9% to be effective August 1, 2017, the PUB established a process which entailed Manitoba Hydro filing additional information to support the requested increase, submissions from registered parties to the proceeding and reply by Manitoba Hydro. On July 31, 2017 the PUB issued Order 80/17 approving a 3.36% interim rate increase in Manitoba Hydro's consumers' billed rates effective August 1, 2017, with all additional revenue generated from the interim rate increase to flow into the previously established Bipole III Deferral Account. This

[1] For a complete list of the approvals requested refer to the Main Application (the "Application") Tab 1, pages 1-3.

account is to be used to fund some of the additional costs that will be incurred when Bipole III comes into service[2].

The PUB has also established a process[3] for dealing with the other matters in the Application, which includes two rounds of information requests to Manitoba Hydro, Intervenor Evidence and an oral hearing followed by participant submissions.

The Application currently before the Board is unique in a number of ways:

i. The requested rates increases (7.9% in each of 2017/18 and 2018/19) are significantly higher than previously requested rate increases[4]. Furthermore, the integrated financial forecast underpinning the 2-year request includes a "rate plan" that calls for continual rate increases of 7.9% through to 2021/22 followed by annual increases of 2%[5]. In contrast the rate plans underpinning previous financial forecasts considered in Manitoba Hydro rate application proceeding called for rate increases in the order of 3.95% per annum out to roughly the end of the next decade.
ii. The Cost of Service Study filed with the Application incorporates the Board's directions flowing from Order 164/16 regarding the principles and appropriate methodology to be used in such studies[6].
iii. The Application introduces alternative residential rate designs[7], a matter that has not been formally addressed for almost 10 years[8].

[2] Now projected to be July 2018
[3] Order 70/17
[4] PUB MFR 12
[5] Based on IFF16 (Appendix 3.1), the basis for the initial Application. Manitoba Hydro's most recent update (Appendix 3.8), which incorporates the August 1, 2017 interim approval, calls for increases of 7.9%/annum through to 2023/24, an increase of 4.54% in 2024/25 followed by 2%/annum increases.
[6] Application, Tab 8
[7] Appendix 9.14
[8] The last time Manitoba Hydro made an Application for changes to its Residential rate design was as part of its 2007/08 Rate Application.

2. PURPOSE OF EVIDENCE

The CONSUMERS COALITION, as a registered participant in the proceeding, retained Econalysis Consulting Services (ECS) to assist and advise the Group with their participation in the proceeding. As part of its engagement, ECS was requested to prepare evidence that would assist both PUB and them in understanding specific aspects of the Application.

ECS is a consulting firm offering regulatory and economic consulting services to clients in the electricity, natural gas, public auto insurance and telecommunications sectors since 1980. The ECS consultant responsible for preparation of the report is Mr. William Harper.

Mr. Harper has over 30 years' experience in the electricity industry gained through positions held with the Ontario Ministry of Energy and Ontario Hydro (and one of its successor companies Hydro One Networks). While at Ontario Hydro, his responsibilities included Ontario Hydro's wholesale rates and Ontario Hydro's regulation of the province's municipal electric utilities; as well as the coordination of the Company's overall participation in various public review processes. He has testified frequently before the Ontario Energy Board (OEB) on rates and regulatory matters. He also testified before the Ontario Environmental Assessment Board with respect to Ontario Hydro's Demand/Supply Plan.

Since joining ECS in 2000, Mr. Harper has provided support to interveners in energy proceedings in British Columbia, Saskatchewan, Manitoba, Ontario and Quebec on matters pertaining to rates, revenue requirements, industry restructuring and resource planning. He has testified as an expert witness before the Manitoba Public Utilities Board, the Manitoba Clean Environment Commission, the Ontario Energy Board and the Quebec Régie de l'énergie.

Mr. Harper's Statement of Qualifications and Duties is attached in Appendix A.

Mr. Harper was specifically requested to provide evidence on the following four topics, which are addressed in the main body of this evidence:

1. The purported change in Manitoba Hydro's financial outlook from that in previous filings.
2. The role of regulatory accounts in rate-setting for regulated utilities and the appropriateness of Manitoba Hydro's proposals regarding its regulatory accounts.
3. Manitoba Hydro's implementation of the cost of service principles and methodology as set out in Order 164/16.
4. Manitoba Hydro's Report on Rate Design for the Residential Class.

The evidence concludes with a summary of conclusions and recommendations.

3. CHANGE IN MANITOBA HYDRO'S FINANCIAL OUTLOOK

In support of higher[9] 7.9% rate increases requested in the Application, Manitoba Hydro provides a number of reasons that are linked to:

i. A change in view regarding the adequacy of Manitoba Hydro's financial performance and the acceptable period for its recovery.
ii. The claim that Manitoba Hydro's financial outlook has deteriorated significantly.

Other experts[10] retained by the Coalition will be addressing the issue of Manitoba Hydro's financial performance in terms of how it should be measured and its "acceptability". The purpose of this Evidence is to specifically examine the claim that Manitoba Hydro's financial outlook has deteriorated significantly, which it links[11] to a reduced outlook for domestic load growth, continued delay in the recovery of opportunity export prices and substantially increased carrying costs related to increased capital costs associated with several projects.

In doing so the ECS Evidence relies on Manitoba Hydro previous and current integrated financial forecasts as prepared by the company, since these reflect Manitoba Hydro's changing views over time regarding its financial outlook. The analysis makes no judgements as to whether underlying assumptions are reasonable or the proposed expenditures prudent and necessary. Similarly, the discussion utilizes Manitoba Hydro's financial metrics. However, in recognition of the emphasis the current

[9] Relative to those request in previous Applications and set out in previous Integrated Financial Forecasts
[10] Morrison Park Advisors
[11] Application, Tab 2, page 3 (lines 1-4)

Application places on "cash flow/capital coverage"[12] and the concerns expressed about the adequacy of Manitoba Hydro's current capital coverage metric[13], the Evidence utilizes a broader capital coverage metric that is based on the difference between cash available from operations and capital expenditures (and more specifically investment in property, plant and equipment) similar to what KPMG describes in their Financial Target Review Report[14]. It is recognized that there are a wide range of financial metrics related to capital coverage that have been developed for and are used for different purposes. The purpose of this metric is simply is to provide a basis by which to compare the various IFFs from a capital coverage perspective. It is not meant to be a replacement or addition to any of Manitoba Hydro's formal financial measures. It was chosen because it does offer one of many perspectives on the adequacy of capital coverage and it can be calculated using data that is readily available from all IFFs.

3.1 Previous Financial Outlooks/Rate Plans

Schedule 1 summarizes some of the key elements of the financial outlooks underpinning: i) Manitoba Hydro's Preferred Development Plan as submitted with its recent NFAT Application, ii) the NFAT development plan most closely approximating the Board's NFAT Decision, iii) the 2015/16 & 2017/17 GRA and iv) last year's application for interim rates effective August 1, 2016. The schedule utilizes Manitoba Hydro's financial metrics (i.e., debt ratio, base capital coverage and interest coverage[15]) as a common basis for comparisons. Also, as noted above, it includes an alternative measure of capital coverage that compares Cash Available from Operations to Total Investment in Plant, Property and Equipment (Overall Capital Coverage).

All of the financial outlooks are similar in that they include:

- A period of annual rate increases in the 3.5% - 4% range followed by annual increases roughly matching inflation.
- An increase in the debt ratio to around 90% for several years.

[12] Tab 2, pages 2 and 15
[13] Tab 2, page 15
[14] Appendix 4.1, pages 22 and 65
[15] The schedule uses EBIDTA interest coverage. However, the values for this measure are not readily available for the NFAT plans.

- Overall Capital Coverage (measured in terms of cash from operations less investment in property, plant and equipment) that is negative overall for most of the initial years.
- A period of more than 15 and up to 20 years before the debt ratio declines to 75%.

For purposes of this evidence the focus will be on comparing the current outlook with those from: i) the last GRA (IFF14) and ii) Manitoba Hydro's subsequent Interim Rate Application (IFF15).

Schedule 1: Key Elements of Previous Financial Outlooks (Electric Operations)

Proceeding	NFAT-Application	NFAT-Update	2015/16 & 2016/17 GRA	August 1, 2016 Interim Rates
Reference IFF	IFF12 – PDP (#14)	IFF13 – Plan 5 with 2x DSM	IFF14	IFF15
Period Covered	2013-2032	2014-2033	2015-2034	2016-2035
Major New Plant	BP III – 2017/18 Keeyask - 2019/20 Conawapa – 2025/26	BP III – 2017/18 Keeyask - 2019/20	BP III – 2018/19 Keeyask - 2019/20	BP III – 2018/19 Keeyask - 2019/20
Annual Rate Increases	3.5% - 2014 3.95% - 2015->‘32	3.95% - 2015 3.74% - 2016->’32	3.95% - 2016->‘31 2% - thereafter	3.95% - 2017->‘29 2% - thereafter
Debt Ratios – Years 1,10 & 15	2013 – 76% 2022 – 90% 2027 – 86%	2014 – 78% 2023 – 92% 2028 – 87%	2015 – 78% 2024 – 90% 2029 – 82%%	2016 - 85% 2025 - 87% 2030 - 80%
Maximum Debt Ratio	90% in 2021/22 -> 2022/23	92% in 2021/22 ->2022/23	90% in 2022/23 -> 2026/27	88% in 2021/22->2023/24
Debt Ratio at/below 75% in	2032 (Year 20)	2032 (Year 19)	2034 (Year 20)	2032 (Year 17)
Capital Coverage Ratio<1.0 (Base Capital Needs)	- 3 of the first 10 Years - 3 of the first 15 Years	- 3 of first 10 Years - 3 of first 15 Years	- 6 of the first 10 Years - 8 of the first 15 Years	- 2 of the first 10 Years - 2 of the first 15 Years
Base Capital Coverage Ratio (Average)	2018-19 - 1.22 2018-27 - 1.69 2018-34 - 2.00	2018-19 - 1.11 2018-27 - 1.44 2018-34 - 1.76	2018-19 - 1.13 2018-27 - 1.09 2018-34 - 1.47	2018-19 - 1.23 2018-27 - 1.38 2018-34 - 1.74
Retained Earnings – Years 1, 10 & 15	2013 - $2.4 B 2022 - $2.6 B 2027 - $4.3 B	2014 - $2.5 B 2023 - $1.9 B 2028 - $3.0 B	2015 - $2.7 B 2024 - $2.0 B 2029 - $2.4 B	2016 - $2.6 B 2025 - $2.9 B 2030 - $4.5 B
Years with Negative Overall Capital Coverage (1)	- 10 of the first 10 Years - 14 of the first 15 years	- 9 of the first 10 Years - 9 of first 15 Years	- 9 of the first 10 years - 9 of the first 15 years	- 7 of the first 10 years - 7 of the first 15 years
Overall Capital Coverage (Average $M))	2018-19 - -1,444 2018-27 - -1,046 2018-34 - -385	2018-19 - -1,361 2018-27 - -324 2018-34 - -36	2018-19 - -2,209 2018-27 - -608 2018-34 - -107	2018-19 - -2,029 2018-27 - -454 2018-34 - 29
EBITDA (Average)	N/A	N/A	2018-19 - 1.44 2018-27 - 1.45 2018-34 - 1.47	2018-19 - 1.49 2018-27 - 1.62 2018-34 - 1.74
Source	NFAT – IFF12, Chapter 11 and Appendix 11.4	NFAT – MH Exhibit, 104-12-4	GRA, Appendices 3.3 & 3.5	Interim Rate Application, Tab 1

Notes:1) Overall Capital Coverage defined as Cash Available from Operations less Investment in Plant, Property and Equipment

2) While the PUB did not recommend a specific development plan, based on a comparison of the PUB's recommendations with Manitoba Hydro's Plan 5 DSM 2 – MH Exhibit 104-12-4 (starting at pdf page 37), Plan 5 closely resembles the PUB's recommendations. (MIPUG/MH I-2 f)

3.2 Recent Financial Performance

The last major GRA dealt with rates for 2014/15 and 2015/16 and Manitoba Hydro's Application was based on IFF14. Subsequent to that Manitoba Hydro filed a Supplementary Application in November, 2015 for interim rates effective August 1, 2016 which was based on IFF15. Schedule 1 compares the forecasts for the period 2014/15 through 2016/17[16] per these two projections with the actual results for the period. Following Schedule 1 is a discussion of the reasons for the changes in the individual line items in operating statement.

Overall, the actual results, in terms of retained earnings and debt ratio, capital coverage and interest coverage (i.e., EBITDA) all generally fall within the range of (or out-perform) the two forecasts. Based on the actual results to-date there is no reason to conclude that there's been a material change from Manitoba Hydro's previous financial outlooks.

[16] The 3 year "forecast" presented for IFF15 includes the actual 2014/15 results per CGAAP.

Schedule 2

Comparative Cumulative Results - $M (2015-2017)

	IFF14	IFF15	Actuals
Revenues			
Domestic Revenues	4526	4589	4420
BP III Reserve	-96	-151	-177
Exports	1293	1201	1275
Other Revenue	43	75	77
Total	5767	5715	5595
Expenses			
O&A	1580	1574	1559
Finance	1553	1650	1646
Depreciation	1228	1153	1145
Water Rentals	359	367	382
Fuel & PP	455	417	395
Taxes	327	329	325
Corp Allocation	25	18	18
Other	6	163	134
Total	5534	5671	5604
Net Movement	-	64	140
Non Control Interest	45	30	33
MH Net Income	276	139	185
Capital Spending (incl DSM)	7587	7826	7129
In-Service Asset (2016/17)	12735	12328	12093
Total Fixed Assets (2016/17)	19490	19876	19172
Regulated Assets (2016/17)	313	298	462
Retained Earnings (2016/17)	2837	2641	2749
Debt Ratio (2016/17)	84%	85%	84%
Base Capital Coverage Ratio (Avg)	0.98	1.04	1.34
Overall Capital Coverage $M (Avg)	-$1,945	-$1,969	-$1,728
EBITDA (Avg)	1.69	1.60	1.59

Notes:
1) 2014/15 based on CGAAP. 2015/16 & 2016/17 based on IFRS
2) IFF14 presentation was not prepared per IFRS (i.e., excluded "Net Movement")
3) Total Fixed Assets Includes Assets In Service (NBV) and Under Construction
4) Overall Capital Coverage is based on Cash from Operations less PP&E Investment
5) Values for Base Capital Coverage, Overall Cash Flow and EBITDA are averages for the period

Sources:
1) IFF14 - 2015/16&16/17 GRA, Appendix 3.4 & 11.13
2) IFF15 - Supplemental Filing for Interim Rates for August 1, 2016, Attachment 1
3) Actual Results - Tab 6 & Appendix 3.8 & COALITION/MH 1-82 & 142 & PUB/MH 1-34 & PUB MFR 23

Variations in individual components of the Income Statement are due, in part, to changes in how various revenues/costs are reported. Examples of this include:

- Other Revenues – IFF15 and Actual Results include the amortization of customer contributions and external billable overheads[17]. Under IFF14 the former was included as an offset to depreciation and the latter was recognized as capital[18].
- Depreciation – For IFF14 depreciation is higher as it includes the regulatory account amortization that is captured in Net Movement under IFF15 and Actual Results for 2015/16 and 2016/17[19].
- Fuel & Purchased Power – The IFF14 reported values include transmission charges attributable to Manitoba Hydro for the use of Manitoba Hydro's own transmission facilities with an offsetting amount included in export revenues. IFF15 and the Actual Results remove these "inter-company" transfers leading to lower reported Fuel and Purchase Power costs and lower reported Export revenues[20].
- Other Expenses – For IFF15 and the Actual Results, Other Expenses also includes expenses related to Power Smart Programs, site restoration and regulatory proceedings.
- Net Movement – For IFF15 and Actual Results, captures impact of additions to deferral accounts net of deferral account amortizations for 2015/16 and 2016/17. However, IFF15 does not include the deferral accounts[21] additions for ineligible overheads and ELG/ASL differences whereas the Actual Results do. The impact of this latter change is reflected in the change in Regulated Assets for 2016/17 as between IFF15 and the Actual Results.

However, individual line items have also been impacted by changes in the underlying drivers:

[17] August 1, 2016 Interim Rate Application, Coalition/MH I-18
[18] August 1, 2016 Interim Rate Application, page 25
[19] Another contributing factor is the treatment of the deferred Conawapa costs in IFF14. According to 2015/16 & 2016/17 GRA, Appendix 11.15 (and PUB/MH I-23 d)), in IFF14 the amortization commences in 2016/17 which would also increase the depreciation costs. However, COALITION MFR 2 from the current proceeding suggests that the commencement date in IFF14 was 2017/18.
[20] August 1, 2016 Interim Rate Application, COALITION/MH I-16 a)
[21] In Order 73/15 the Board directed Manitoba Hydro to continue to use ASL-based as opposed to ELG-based depreciation, subject to further information being provided, and to not expense an additional $20 M in overheads. However, IFF15 did not reflect these directives.

- Domestic Revenues – Actual revenues are lower due to lower volumes and lower rates as indicated in Schedule 3.

Schedule 3 - Domestic Revenue Drivers

	2014/15	2015/16	2016/17
Domestic Volumes			
IFF14	22,214 GWh	22,458 GWh	22,458 GWh
IFF15	22,458 GWh (actual)	22,593 GWh	23,068 GWh
Actual	22,458 GWh	21,654 GWh	22,025 GWh
Rate Increases			
IFF14	2.75%- May 1, 2014	3.95% -Apr 1, 2015	3.95% -Apr 1, 2016
IFF15	2.75%- May 1, 2014	3.95% -Aug 1, 2015	3.95% - Apr 1 2016
Actual	2.75%- May 1, 2014	3.95% -Aug 1, 2015	3.36% -Aug 1, 2016

Sources: 1) 2015/16 & 2016/17 GRA, Appendix 11.19 and Appendix 3.3
2) Supplemental Application, Attachment 16 and Attachment 1
3) PUB MFR 65, Attachment 1 and PUB MFR 12

- Finance Expense – IFF15 and actual finance expense are both higher as a result of lower levels of capitalized interest due to spending delays[22] and foreign exchange rate increases[23].

Schedule 4 - Foreign Exchange Rates

	2014/15	2015/16	2016/17
Exchange Rate (C$/US$)			
IFF14	1.10	1.12	1.12
IFF15	1.14 (actual)	1.30	1.32
Actual	1.14	1.31	1.31

Source: 1) 2015/16 & 2016/17 GRA, Appendix 3.3, page 3
2) Supplement Filing for Interim Rates Effective August 1, 2016, Attachment 1, page 3
3) PUB MFR 53, Attachment 1, page 18

[22] Lower capital spending increases finance expense as the cost of new debt is less than the interest capitalization rate - see Tab 2, page 18.
[23] Supplement Filing for Interim Rates Effective August 1, 2016, page 26

- Export Revenues – Actual export revenues are roughly equivalent to forecast. While US export prices were lower than forecast, this was offset by higher foreign exchange rates and higher sales volumes.

Schedule 5 – Export Revenue Drivers

	2014/15	2015/16	2016/17
Export Volume			
IFF14	10,035 GWh	9,076 GWh	7,304 GWh
IFF15	10,010 GWh[24] (actual)	9,305 GWh	7,284 GWh
Actual	10,010 GWh	10,281 GWh	11,271 GWh
Avg Export Revenue			
IFF14	$34.67/MWh	$42.39/MWh	$55.31/MWh
IFF15	$37.82/MWh (actual)	$37.29/MWh	$49.42/MWh
Actual	$37.82/MWh	$38.71/MWh	$39.32/MWh

Sources:
1) 2015/16&16/17 GRA, Appendix 11.19
2) Supplement Filing for Interim Rates Effective August 1, 2016, Attachment 16
3) PUB MFR 24 and PUB/MH I-153 c)
4) COALITION MFR 6

- O&A Expense – Lower than forecast, in part due to the achievement of planned operational position reductions earlier than expected[25].
- Capital Spending and In-Service Assets – Actual results are lower than either forecast due to a combination of spending delays and lower costs for in-service assets[26].

[24] This value is reported in PUB MFR 24. However, the 2016/17 Annual Report shows a value of 9,811 GWh
[25] Supplement Filing for Interim Rates Effective August 1, 2016, page 48 and Attachment 33
[26] COALITION/MH I-142

3.3 Current Application – Initial Financial Outlook (IFF16)

The financial projection (IFF16) underpinning the 2017/18 & 2018/19 Application called for significantly higher rate increases in 2017/18 and 2018/19 than those in previous financial plans. In order to determine the extent to which the financial outlook for the Corporation has changed over this period, it is useful to compare the past financial outlooks with a financial projection that includes all with the forecast assumptions used in IFF16 but assumes rate increases for each of the two years (and beyond) similar to those included in the previous financial projections (i.e., 3.95%/annum in the initial years)[27].

The following sections compare this variation of IFF16 looking at three difference timeframes:

i. The test period (2017/18 & 2018/19) for the current Application,
ii. The period from 2017/18 through to 2026/27, the timeframe over which Manitoba Hydro now seeks to achieve its 75% target debt ratio, and
iii. The period from 2017/18 through to 2033/34, a period reflective of previous plans and the PUB's Order 59/16.

3.3.1 Test Period Outlook (2017/18-2018/19)

Schedule 6 provides a comparison of the financial results for the period 2017/18-2018/19 based on IFF14, IFF15 and IFF16 (assuming rate increases of 3.95% per annum[28]). Again, following the schedule is a discussion of the changes in the individual line items of the operating statement. This discussion flags variations in the domestic load forecast, export prices, capital spending/in-service, O&A costs and interest rates as being the key drivers in changes to the overall financial outlook.

While the outlook for Overall Capital Coverage has deteriorated, the outlook for EBITDA is improved over previous forecasts and the Debt Ratio is in line with previous forecasts. As a result, from an overall perspective, there is no reason to conclude that the financial outlook has fundamentally changed.

[27] Such a projection can be found in Appendix 3.4
[28] See Appendix 3.4

Schedule 6

Comparative Results - $M (2018-19)

	IFF14	IFF15	IFF16 @3.95%
Revenues			
Domestic Revenues	3406	3421	3299
BP III Reserve	-47	-90	-105
Exports	936	923	886
Other Revenue	29	57	61
Total	4323	4311	4141
Expenses			
O&A	1128	1128	1019
Finance	1333	1295	1202
Depreciation	966	870	867
Water Rentals	224	226	236
Fuel & PP	409	362	301
Taxes	277	281	277
Corp Allocation	16	16	16
Other	4	202	224
Total	4361	4380	4143
Net Movement	-	83	174
Non Control Interest	12	7	10
MH Net Income	-26	22	182
Capital Spending	5203	4932	5800
In-Service Asset (2018/19)	17687	17248	17505
Total Fixed Assets (2018/19)	23727	23475	24101
Regulated Assets (2018/19)	396	787	633
Retained Earnings (2018/19)	2812	2663	2912
Debt Ratio (2018/19)	86%	87%	86%
Base Capital Coverage Ratio (Avg)	1.13	1.23	1.23
Overall Captial Coverage $M (Avg)	-$2,209	-$2,029	-$2,644
EBITDA (Avg)	1.44	1.49	1.58

Notes: 1) IFF14 presentation was not prepared per IFRS (i.e., excluded "Net Movement")
2) Total Fixed Assets Includes Assets In Service (NBV) and Under Construction
3) Overall Capital Coverage is based on Cash from Operations less PP&E Investments

Sources: 1) IFF14 - 2015/16&16/17 GRA, Appendix 3.4 & 11.13
2) IFF15 - Supplemental Filing for Interim Rates for August 1, 2016, Attachment 1
3) IFF16 @ MH15 Rates - Appendix 3.4

Again, variations in individual components of the Income Statement are partly due to changes in how various revenues/costs are reported. These changes, as noted in section 3.2, primarily impact: i) Other Revenue, ii) Depreciation, iii) Fuel and Power Purchased, iv) Other Expenses and v) Net Movement. In addition, the following reporting and accounting changes impact any comparisons for this period:

- The reporting of the amortization of the BP III deferral account changed from IFF14 (as an offset to Depreciation) to IFF15 (as Other Revenue) to IFF16 (reported explicitly under BP III Reserve)[29].
- In IFF14, deferred Conawapa costs were amortized over a 30 year period starting in 2016/17[30]. However, in IFF15 this timing was changed and it was assumed that Conawapa costs would be treated as a regulatory deferral account balance and amortized over a period of 30 years commencing in 2017/18[31]. In contrast, IFF16 assumed that Conawapa's costs would be recognized in a regulatory deferral account and amortized starting in 2019/20[32]. This latter change of timing in IFF16 accounts for the lower 2018/19 value for Regulated Assets[33] in IFF16 vs. IFF15.

However, some individual line items that have changed as a result of changes in the underlying drivers:

- Domestic Revenues - IFF16 domestic revenues for the period are lower primarily due to a decrease in the domestic load forecast as set out in the following table.

[29] COALITION MFR 2
[30] 2015/16 & 2016/17 GRA, Appendix 11.15. However, it appears that in IFF14 the remaining balance was not included in Regulatory Assets.
[31] Supplementary Filing for Interim Rates Effective April 1, 2016, Attachment 1, page 10
[32] Tab 3, page 19
[33] Regulated Assets represent the outstanding balance for Manitoba Hydro's regulatory asset accounts

Schedule 7 - Domestic Revenue Drivers (2017/18-2018/19)

	2017/18	2018/19
Domestic Volumes		
IFF14	22,881 GWh	23,009 GWh
IFF15	22,971 GWh	22,949 GWh
IFF16	22,519 GWh	22,259 GWh

Sources: 1) 2015/16 & 2016/17 GRA, Appendix 11.19
2) Supplemental Application, Attachment 16
3) PUB MFR 24

- Exports – In IFF16, unit export revenues are materially lower. However, the impact is partially offset by higher export volumes over the period as shown in the following table. It should be noted that the reported reduction in unit export revenues understates the reduction in forecast US export prices due to changes in assumption regarding exchange rates.

Schedule 8 – Export Revenue Drivers

	2017/18	2018/19
Export Volume		
IFF14	7,025 GWh	6,999 GWh
IFF15	6,854 GWh	6,962 GWh
IFF16	9,074 GWh	7,165 GWh
Avg Export Revenue		
IFF14	$58.28 / MWh	$61.50 / MWh
IFF15	$61.53 / MWh	$64.10 / MWh
IFF16	$44.35 / MWh	$54.41 / MWh
Exchange Rates – C$/US$		
IFF14	1.12	1.12
IFF15	1.25	1.22
IFF16	1.28	1.25

Sources: 1) 2015/16&16/17 GRA, Appendices 3.1 and 11.19
2) Supplementary Application, Attachments 1 and 16
3) PUB MFR 24 and Appendix 3.1

- O&A – IFF16 O&A expenses are lower as result of Manitoba Hydro's cost reduction plan which focuses on workforce reductions and procurement savings through supply chain management initiatives[34].
- Finance Expense – Finance expense for IFF16 is lower primarily as a result of lower interest rates and a shift to shorter term borrowing[35].

Schedule 9 – Interest Rate Forecasts

	2017/18	2018/19
New MH Long Term Cdn Interest Rates		
IFF14	4.80%	5.00%
IFF15	3.80%	4.40%
IFF16	2.50%	2.95%
New MH Short Term Cdn Interest Rate		
IFF14	3.10%	3.45%
IFF15	1.40%	2.40%
IFF16	0.50%	0.85%

Sources: 1) Supplementary Application, Attachment 1, page 3
2) Appendix 3.1, page 10

- Other Expenses – IFF16 includes $54 M in restructuring costs[36]. However, this is partially offset by lower spending on DSM over the period relative to IFF15[37].
- Capital Spending – The increase for IFF16 over IFF15 is primarily due to higher levels of spending on Keeyask, BP III and the Manitoba-Minnesota 500 kV Transmission Line[38].

The current outlook (IFF16) shows deterioration in both domestic load levels and export revenues (relative to previous forecasts) and an increase in capital spending during

[34] Tab 3, page 10
[35] Appendix 3.5
[36] Tab 6, page 37
[37] COALITION/MH I-48 d)
[38] Appendix 5.4, pages 3, 9, 11, 12 and 15

period. Offsetting these negative factors are more favourable forecasts of O&A and interest expenses, combined with deferral/amortization of ineligible overheads and ASL/ELG depreciation differences.

3.3.2 Ten Year Period (2017/18 to 2026/27)

Schedule 10 provides a comparison of the financial results for the period ten year period up to 2026/27 based on IFF14, IFF15 and IFF16 (assuming rate increases of 3.95% per annum).

The overall results are similar to those seen for the test period (Section 3.3.1). The outlook for Overall Capital Coverage has deteriorated but the outlook for EBITDA is improved over previous forecasts and the Debt Ratio is in line with previous forecasts. Again, from an overall perspective, there is no reason to conclude that the financial outlook has fundamentally changed.

As in the previous sections, variations in individual components of the Income Statement are partly due to changes in how various revenues/costs are reported and/or accounted for. These changes, as noted in sections 3.2 and 3.3.1, primarily impact: i) BP III Reserve, ii) Other Revenue (IFF14 vs IFF15 & IFF16), iii) Depreciation, iv) Fuel and Power Purchased, v) Other Expenses and vi) Net Movement. In addition, for purposes of IFF16, the deferral of both ineligible overheads and the ELG/ASL differences was assumed to cease after 2022/23[39] which also impacts the Net Movement comparisons over this period.

The subsequent discussion again identifies changes in the domestic load forecast, export prices, capital spending/in-service costs, O&A costs and interest rates as being the key drivers underpinning changes to the financial outlook.

[39] MIPUG MFR 5

Schedule 10

Cumulative Comparative Results - $M (2018-2027)

	IFF14	IFF15	IFF16 - 3.95%
Revenues			
Domestic Revenues	20,567	20,545	19,499
BP III Reserve	- 47	- 90	198
Exports	8,024	7,997	6,493
Other Revenue	156	576	332
Total	28,702	29,028	26,489
Expenses			
O&A	6,141	6,141	5,364
Finance	11,458	10,248	9,078
Depreciation	6,596	6,208	6,151
Water Rentals	1,251	1,253	1,228
Fuel & PP	2,471	2,141	1,434
Taxes	1,517	1,551	1,625
Corp Allocation	80	80	80
Other	26	877	1,240
Total	29,544	28,500	26,199
Net Movement	-	57	615
Non Control Interest	12	- 6	- 33
MH Net Income	- 830	578	903
Capital Spending (incl DSM)	11,944	11,918	14,435
In-Service Asset (2026/27)	24,878	24,942	26,902
Total Fixed Assets (2026/27)	25,103	25,114	27,171
Regulated Assets (2026/27)	333	761	1,074
Retained Earnings (2026/27)	2,007	3,219	3,632
Debt Ratio (2026/27)	90%	86%	86%
Base Capital Coverage Ratio (Avg)	1.09	1.38	1.46
Overall Capital Coverage $M (Avg)	-608.30	-454.20	-766.00
EBITDA (Avg)	1.45	1.62	1.67

Notes: 1) IFF14 presentation was not prepared per IFRS (i.e., excluded "Net Movement")
2) Total Fixed Assets Includes Assets In Service (NBV) and Under Construction
3) Overall Capital Coverage is based on Cash from Operations less Investment in PP&E

Sources: 1) 2015/16& 2016/17 GRA, Appendix 3.4 & 11.13
2) Supplemental Filing for Interm Rates for August 1, 2017, Attachment 1
3) Appendix 3.4 and COALITION/MH II-48 a)

Individual line items that have seen major changes as result of the underlying drivers include:

- Domestic Revenues – Where the variance between the load forecast used in IFF16 and those used in the previous plans continues to increase over the period.

Schedule 11 – Domestic Revenue Drivers (2017/18-2026/27)

	2017/18	2022/23	2026/27
Domestic Volumes			
IFF14	22,881 GWh	23,664 GWh	24,572 GWh
IFF15	22,971 GWh	23,503 GWh	24,407 GWh
IFF16	22,519 GWh	22,210 GWh	22,721 GWh

Sources: 1) 2015/16 & 2016/17 GRA, Appendix 11.19
2) Supplemental Application, Attachment 16
3) PUB MFR 24

The graphs provided in response to PUB/MH I-56 indicate that the most of the variation between IFF15 and IFF16 is due to changes in the forecast for the Top Consumers (i.e., large industrial customers).

- Export Revenues – Export revenues are lower due to a significantly lower forecast for export prices[40] and the delayed in-service date for Keeyask[41], offset somewhat by higher export volumes as a result of lower domestic volumes and more favourable water flows at the start of the period[42].

[40] Tab 3, page 14
[41] Tab 3, page 16
[42] Tab 3, page 16

Schedule 12 – Export Revenue Drivers

	2017/18	2022/23	2026/27
Export Volume			
IFF14	7,025 GWh	10,809 GWh	9,881 GWh
IFF15	6,854 GWh	10,850 GWh	9,827 GWh
IFF16	9,074 GWh	10,876 GWh	10,356 GWh
Avg Export Revenue			
IFF14	$58.28 / MWh	$82.80 / MWh	$88.83 / MWh
IFF15	$61.53 / MWh	$86.29 / MWh	$87.41 / MWh
IFF16	$44.35 / MWh	$70.46 / MWh	$66.85 / MWh
Exchange Rates – C$/US$			
IFF14	1.12	1.10	1.10
IFF15	1.25	1.16	1.16
IFF16	1.28	1.15	1.15

Sources: 1) 2015/16&16/17 GRA, Appendices 3.1 and 11.19
2) Supplementary Application, Attachments 1, 16 and 22
3) PUB MFR 24 and Appendix 3.2

- O&A Expense – As in the 2017/18-2018/19 period, IFF16 O&A expenses are lower as a result of the continuing effect of Manitoba Hydro's current cost reduction efforts[43].
- Finance Expense – IFF16 finance expense also continues to be lower over this period as a result of lower interest rates and a shift to shorter term borrowing[44]. Also serving to lower finance expense in IFF16 is the delay in the in-service date for Keeyask. However, the impact of these factors is offset (to some extent) by the higher level of capital spending (and ultimately in-service costs).

[43] Tab 3, page 10
[44] Appendix 3.5

Schedule 13 – Interest Rate Forecasts

	2017/18	2022/23	2026/27
Cdn 10 Year + Interest Rate			
IFF14	4.80%	5.20%	5.20%
IFF15	3.35%	4.60%	4.60%
IFF16	2.80%	4.55%	4.55%
Cdn Short Term Interest Rate			
IFF14	3.10%	3.90%	3.90%
IFF15	1.40%	3.00%	3.00%
IFF16	0.50%	2.70%	2.79%

Sources: 1) COALITION/MH I-63

- Capital Spending and In-Service Assets - the increase for IFF16 is again primarily due to higher levels of spending on Keeyask, BP III and the Manitoba-Minnesota 500 kV Transmission Line[45].

The overall result is similar to what was seen for the 2017/18-2018/19 period with the negative influences associated with decreases in both domestic load levels and export revenues (relative to previous forecasts) and increases in capital spending during the period being offset by lower interest rates, lower O&A costs and the deferral/amortization of ineligible overheads and ASL/ELG depreciation differences.

3.3.3 Outlook to 2033/34

Schedule 14 offers a comparison of the financial results for the period up to 2033/34 based on IFF14, IFF15 and IFF16 (assuming rate increases of 3.95% per annum to 2028/29 and 2% per annum thereafter). As in the earlier sections, the domestic load forecast, export prices, capital spending/in-service costs, O&A costs and interest rates are the key drivers giving rise to the changes seen in IFF16.

[45] Tab 5, page 19

Again, the overall results are similar to those seen for the previous sections where the outlook for Overall Capital Coverage has deteriorated but the outlook for EBITDA is improved over previous forecasts and the Debt Ratio is in line with previous forecasts. Given these results, there is no reason to conclude that the financial outlook has fundamentally changed.

Schedule 14

Cumulative Comparative Results - $M (2018-2034)

	IFF14	IFF15	IFF16 - 3.95%
Revenues			
Domestic Revenues	41,654	41,202	38,635
BP III Reserve	- 47	- 90	198
Exports	14,371	13,938	11,626
Other Revenue	287	839	600
Total	56,266	55,891	51,028
Expenses			
O&A	11,190	11,190	9,799
Finance	20,154	17,525	16,650
Depreciation	12,434	11,764	11,802
Water Rentals	2,195	2,195	2,154
Fuel & PP	4,624	3,956	2,451
Taxes	2,700	2,756	2,861
Corp Allocation	123	113	109
Other	44	1,613	1,849
Total	53,470	51,117	47,676
Net Movement	-	72	377
Non Control Interest	- 72	- 83	- 95
MH Net Income	2,725	4,760	3,666
Capital Spending (incl DSM)	17,429	17,683	20,036
In-Service Asset (2033/34)	24,921	25,054	26,909
Total Fixed Assets (2033/34)	25,176	25,197	27,173
Regulated Assets (2033/34)	311	532	836
Retained Earnings (2033/34)	5,557	7,402	6,395
Debt Ratio (2033/34)	75%	69%	75%
Base Capital Coverage Ratio (Avg)	1.47	1.74	1.65
Overall Capital Coverage $M (Avg)	-106.94	29.06	-217.29
EBITDA (Avg)	1.71	1.88	2.00

Notes:
1) IFF14 presentation was not prepared per IFRS (i.e., excluded "Net Movement")
2) Total Fixed Assets Includes Assets In Service (NBV) and Under Construction
3) Overall Capital Coverage is based on Cash from Operations less Investment in PP&E

Sources:
1) 2015/16& 2016/17 GRA, Appendix 3.4 and 11.13
2) Supplemental Filing for Interm Rates for August 1, 2017, Attachment 1
3) Appendix 3.4 and COALITION/MH II-48 a)&b) and COALITION/MH II-50

The reporting and accounting changes noted in the previous sections account for some of the differences between the results for IFF16 (at 3.95% rate increases up to 2028/29) and the results of the previous financial plans. In addition the same key drivers as noted in section 3.3.2 continue to influence the results:

- Load Forecast – Where the variance between the load forecast used in IFF16 and those used in the previous plans continues to increase through to 2033/34 leading to reduced domestic revenues. Again, the major differences lie in the forecast for the Top Consumers[46].

Schedule 15 – Domestic Revenue Drivers (2017/18-2033/34)

	2017/18	2026/27	2033/34
Domestic Volumes			
IFF14	22,881 GWh	24,572 GWh	26,546 GWh
IFF15	22,971 GWh	24,407 GWh	26,926 GWh
IFF16	22,519 GWh	22,721 GWh	24,915 GWh

Sources: 1) 2015/16 & 2016/17 GRA, Appendix 11.19
2) Supplemental Application, Attachment 16
3) PUB MFR 24

- Export Volumes/Prices – While the reduction in the Domestic load forecast makes more energy available for export, the lower forecast for export prices in IFF16[47] more than offset this leading to a reduction in export revenues.

[46] PUB/MH I-56
[47] Tab 3, page 16 and PUB MFR 80

Schedule 16 – Export Revenue Drivers

	2017/18	2026/27	2033/34
Export Volume			
IFF14	7,025 GWh	9,881 GWh	7,743 GWh
IFF15	6,854 GWh	9,827 GWh	7,103 GWh
IFF16	9,074 GWh	10,356 GWh	8,400 GWh
Avg Export Revenue			
IFF14	$58.28 / MWh	$88.83 / MWh	$104.41 / MWh
IFF15	$61.53 / MWh	$87.41 / MWh	$103.03 / MWh
IFF16	$44.35 / MWh	$66.85 / MWh	$84.99 / MWh
Exchange Rates – C$/US$			
IFF14	1.12	1.10	1.10
IFF15	1.25	1.16	1.16
IFF16	1.28	1.15	1.15

Sources: 1) 2015/16&16/17 GRA, Appendices 3.1 and 11.19
2) Supplementary Application, Attachments 1, 16 and 22
3) PUB MFR 24 and Appendix 3.2

- Manitoba Hydro's Cost Reduction Initiatives – As in the 2017/18-2026/27 period, IFF16 O&A expenses are lower as a result of the continuing effect of Manitoba Hydro's current cost reduction efforts[48].
- Interest Rates and Debt Management – IFF16 finance expense is also lower over this period as a result of lower interest rates and a shift to shorter term borrowing[49]. Also serving to lower finance expense in IFF16 is the delayed in-service date for Keeyask. However, the impact of these factors is offset (to some extent) by the higher level of capital spending (and ultimately in-service costs).

[48] Tab 3, page 10
[49] Appendix 3.5

Schedule 17 – Interest Rate Forecasts

	2017/18	2026/27	2033/34
Cdn 10 Year + Interest Rate			
IFF14	4.80%	5.20%	5.20%
IFF15	3.35%	4.60%	4.60%
IFF16	2.80%	4.55%	4.55%
Cdn Short Term Interest Rate			
IFF14	3.10%	3.90%	3.90%
IFF15	1.40%	3.00%	3.00%
IFF16	0.50%	2.70%	2.70%
Sources: 1) COALITION/MH I-63			

- Capital Spending and In-Service Additions – Are again higher in IFF16 primarily due to the higher levels of spending on Keeyask, BP III and the Manitoba-Minnesota 500 kV Transmission Line.

The overall result is again similar to what was seen in the previous sections where the negative influences associated with decreases in both domestic load levels and export revenues (relative to previous forecasts) and increases in capital spending during period are largely offset largely by lower interest rates, lower O&A costs and the deferral/amortization of ineligible overheads and ASL/ELG depreciation differences.

3.3 Current Application-Updated Financial Outlook (MH16-Update with Interim)

On July 11, 2017 Manitoba Hydro filed an update of its financial forecast for electric operations incorporating new forecasts for Manitoba load, electricity export prices and economic and financial indicators. In addition the update reflected changes in water conditions since IFF16 was produced[50]. Subsequently, on July 31, 2017, the PUB issued its Decision regarding Manitoba Hydro's request for an interim rate increase of 7.9% effective August 1, 2017. In Order 89/17 the Board approved an interim rate increase of 3.36% effective August 1, 2017. As a result, in responding to the first round of information requests, Manitoba Hydro incorporated the 3.36% rate increase approval into its updated financial forecast where applicable. This revised financial forecast for electric operations is referred to as MH16 Update with Interim ("MH16 U/I")[51].

The following table compares the electric operations results for IFF16 and MH16 U/I across each of the three time periods previously discussed where in both cases the rate increases assumed are consistent with those from MH15 (i.e., 3.95% for April 1, 2018 through April 1, 2029 followed by 2% per annum thereafter)[52].

After the test period (2017/18-2018/19) all of the financial metrics associated with IFF16 U/I deteriorate relative to IFF16. For the ten year period (2017/18 to 2026/27), while the Overall Capital Coverage has deteriorated further relative to the earlier IFF14 and IFF15 forecasts, both the interest coverage (EBITDA) and Debt Ratio metric still fall within the range of these earlier outlooks. However, in the second decade the debt ratio also falls outside the range while the interest coverage ratio continues to be comparable with the earlier forecasts. It is here that one could suggest there is more of a change from previous outlooks. However, extending the 3.95% annual increases through to 2033/34 (just a couple of years past what was contemplated in IFF14) would permit Manitoba Hydro to achieve its target debt ratio in 2034/35[53].

[50] Supplement to Tab 3, page 1
[51] Appendix 3.8
[52] PUB/MH I-34, Attachment 2
[53] COALITION/MH II-7 a)

Schedule 14

Cumulative Comparative Results - $M (at MH15 Rate Increases)

	2018-2019		2018-2027		2018-2034	
	IFF16	MH16 U/I	IFF6	MH16 U/I	IFF16	MH16 U/I
Revenues						
Domestic Revenues	3,299	3,296	19,499	19,251	38,635	38,326
BP III Reserve	- 105	- 148	198	194	198	194
Exports	886	983	6,493	6,373	11,626	11,220
Other Revenue	61	61	332	332	600	600
Total	4,141	4,192	26,489	26,150	51,028	50,343
Expenses			-		-	
O&A	1,019	1,019	5,364	5,364	9,799	9,799
Finance	1,202	1,226	9,078	9,496	16,650	17,791
Depreciation	867	867	6,151	6,154	11,802	11,809
Water Rentals	236	250	1,228	1,238	2,154	2,167
Fuel & PP	301	264	1,434	1,412	2,451	2,350
Taxes	277	277	1,625	1,630	2,861	2,883
Corp Allocation	16	16	80	80	109	113
Other	224	225	1,240	1,241	1,849	1,850
Total	4,143	4,145	26,199	26,620	47,676	48,767
			-		-	
Net Movement	174	186	615	636	377	397
Non Control Interest	10	9	- 33	- 35	- 95	- 100
MH Net Income	182	241	903	130	3,666	1,860
			-		-	
Capital Spending	5,800	5,801	14,435	14,436	20,036	20,037
In-Service Asset (Final Year)	17,505	17,332	26,902	26,732	26,909	26,739
Total Fixed Assets (Final Year)	24,101	24,077	27,171	27,143	27,173	27,139
Regulated Assets (Final Year)	633	647	1,074	1,098	836	860
Retained Earnings (Final Year)	2,912	2,990	3,632	2,879	6,395	4,619
Debt Ratio (Final Year)	0.86	0.85	0.86	0.88	0.75	0.81
Base Capital Coverage Ratio (Avg)	1.23	1.38	1.46	1.368	1.65	1.52
Overall Capital Coverage $M (Avg)	- 2,644	- 2,613	- 766	- 842	- 217	- 321
EBITDA (Avg)	1.58	1.59	1.67	1.61	2.00	1.76

Notes: 1) Total Fixed Assets Includes Assets In Service (NBV) and Under Construction
2) Overall Capital Coverage is based on Cash from Operations less Investment in PP&E

Sources: 1) Appendix 3.4
2) PUB/MH I-34, Attachment 2

Both IFF16 and IFF16 U/I generally use the same reporting and accounting with one exception. MH16 U/I defers the commencement of the amortization of the ELG/ASL deferral account from 2017/18 to 2019/20. This change accounts for most of difference in both Net Movement and Regulatory Assets as between the two forecasts. The other main differences between the two outlooks are attributable to the following key drivers:

- Load Forecast – Where the variance between the load forecast used in MH1616 U/I and IFF16 is due partly to a further reduction in the load forecast coupled with a reduction in the interim rates approved for August 1, 2017 versus those assumed in

IFF16. This reduction is, in part, due to Manitoba Hydro incorporating the 7.9% annual increases (as opposed to the previous 3.95%) into its load forecast methodology[54].

Schedule 15 – Domestic Revenue Drivers (2017/18-2033/34)

	2017/18	2026/27	2033/34
Domestic Volumes			
IFF14	22,881 GWh	24,572 GWh	26,546 GWh
IFF15	22,971 GWh	24,407 GWh	26,926 GWh
IFF16	22,519 GWh	22,721 GWh	24,915 GWh
MH16 U/I	22,510 GWh	22,531 GWh	24,614 GWh

Sources: 1) COALITION/MH I-49

- Export Volumes/Prices – In the near term export volumes are higher primarily due to improved hydraulic conditions. Export prices are also higher due to the weaker Canadian dollar. However, over the longer term export prices decline[55] relative to past forecasts and export revenues are lower.

Schedule 16 – Export Revenue Drivers

	2017/18	2026/27	2033/34
Export Volume			
IFF14	7,025 GWh	9,881 GWh	7,743 GWh
IFF15	6,854 GWh	9,827 GWh	7,103 GWh
IFF16	9,074 GWh	10,356 GWh	8,400 GWh
MH16 U/I	10,505 GWh	10,458 GWh	8,292 GWh

[54] COALITION/MH I-22
[55] Supplement to Tab 3, pages 6-7

Avg Export Revenue			
IFF14	$58.28 / MWh	$88.83 / MWh	$104.41 / MWh
IFF15	$61.53 / MWh	$87.41 / MWh	$103.03 / MWh
IFF16	$44.35 / MWh	$66.85 / MWh	$84.99 / MWh
MH16 U/I	$44.81 / MWh	$62.03 / MWh	$80.79 / MWh
Exchange Rates – C$/US$			
IFF14	1.12	1.10	1.10
IFF15	1.25	1.16	1.16
IFF16	1.28	1.15	1.15
MH16 U/I	1.35	1.17	1.17

Sources: 1) 2015/16&16/17 GRA, Appendices 3.1 and 11.19
2) Supplementary Application, Attachments 1, 16 and 22
3) PUB MFR 24 and Appendix 3.2
4) PUB MFR 24 (updated) and PUB MFR 53 (Updated)

- Interest Rates and Debt Management – Over the longer term the MH16 U/I finance expense is higher than that in IFF16 due higher forecast interests rates.

Schedule 17 – Interest Rate Forecasts

	2017/18	2026/27	2033/34
Cdn 10 Year + Interest Rate			
IFF14	4.80%	5.20%	5.20%
IFF15	3.80%	4.60%	4.60%
IFF16	3.15%	4.55%	4.55%
MH16 U/I	3.15%	4.95%	4.95%
Cdn Short Term Interest Rate			
IFF14	3.10%	3.90%	3.90%
IFF15	1.40%	3.00%	3.00%
IFF16	0.50%	2.70%	2.70%
MH16 U/I	0.55%	3.05%	3.05%

Sources: 1) COALITION/MH I-63

3.4 Conclusions

The following schedule summarizes some of the key results from the various forecasts. Apart from the Overall Capital Coverage metric - which is not one of Manitoba Hydro's formal financial measures/targets – the results for IFF16 are not out of line with the previous forecasts. As result, at the time of the initial Application there does not appear to have been a fundamental change in the financial outlook for the Corporation.

With the update and after accounting for the August 1, 2017 interim increase the outlook (IFF16 U/I) does deteriorate such that not only the Overall Capital Coverage but also the Debt Ratio and Retained Earnings are out of line with the earlier forecasts. However, it should be noted that extending the 3.95% annual increases through to 2033/34 (just a couple of years past what was contemplated in IFF14) would permit Manitoba Hydro to achieve its target debt ratio in 2034/35[56] and bring the Retained Earnings for that year virtually within the range of the previous forecasts. As a result, even the recently updated IFF16 does not appear to present a fundamental change in the financial outlook for the Corporation.

Finally, as the discussion of the key drivers indicated, key issues with respect to the financial outlook are:

- Manitoba Hydro's capital spending program,
- Manitoba Hydro's domestic load forecast, in particular the forecast for the Top Consumers, which account for well over half of the variation in the long term[57],
- Export prices, particularly from 2022/23 and beyond when Keeyask is in-service and Manitoba Hydro has greater volumes of energy (including surplus dependable energy) for export.[58], and
- Interest rate forecasts.

[56] COALITION/MH II-7 a)
[57] Based on a comparison of the forecasts for 2033/34 per the 2015 and 2017 Load Forecasts
[58] PUB/MH I-50

Schedule 18 - Key Financial Outlook Results (Electric Operations)

Proceeding	2015/16 & 2016/17 GRA	August 1, 2017 Interim Rates	IFF16 with MH15 Rate Increases	IFF16 U/I with MH15 Rate Incr.
Reference IFF	IFF14	IFF15	IFF16	IFF16 U/I
Period Covered	2015-2034	2016-2035	2017-2036	2017-2036
Major New Plant	BP III – 2018/19 Keeyask - 2019/20	BP III – 2018/19 Keeyask - 2019/20	BP III – 2018/19 Keeyask - 2021/22	BP III – 2018/19 Keeyask - 2021/22
Annual Rate Increases	3.95% - 2016->'31 2% - thereafter	3.95% - 2017->'29 2% - thereafter	3.95% - 2017->'29 2% - thereafter	3.95% - 2017->'29 2% - thereafter
Debt Ratios	2019 – 86% 2027 – 90% 2034 – 75%	2019 – 87% 2027 – 86% 2034 – 69%	2019 – 86% 2027 – 86% 2034 – 75%	2019 – 85% 2027 – 88% 2034 – 81%
Maximum Debt Ratio	90% in 2022/23 -> 2026/27	88% in 2021/22->2023/24	87% in 2019/20 ->2020/21 and 2021/23->2024/25	88% in 2024/25 ->2027/29
Debt Ratio at/below 75% in	2034 (Year 20)	2032 (Year 17)	2034 (Year 18)	After 2036
Base Capital Coverage Ratio<1.0	- 6 of the first 10 Years - 8 of the first 15 Years	- 2 of the first 10 Years - 2 of the first 15 Years	- None of first 10 Years - None of first 15 Years	- None of first 10 Years - None of first 15 Years
Base Capital Coverage Ratio (Average)	2018-19 – 1.13 2018-27 – 1.09 2018-34 – 1.47	2018-19 – 1.23 2018-27 – 1.38 2018-34 – 1.74	2018-19 – 1.23 2018-27 – 1.46 2018-34 – 1.65	2018-19 – 1.38 2018-27 – 1.37 2018-34 – 1.52
Retained Earnings ($M)	2019 – 2,812 2027 - 2,007 2034 - 5,557	2019 - 2,663 2027 - 3,219 2034 - 7,402	2019 - 2,912 2027 - 3,632 2034 - 6,395	2019 - 2,990 2027 - 2,879 2034 - 4,619
Years with Negative Overall Capital Coverage (1)	- 9 of the first 10 years - 9 of the first 15 years	- 7 of the first 10 years - 7 of the first 15 years	- 7 of the first 10 years - 7 of the first 15 years	- 7 of the first 10 years - 7 of the first 15 years
Overall Capital Coverage (Average $M))	2018-19 – -2,209 2018-27 – -608 2018-34 - -107	2018-19 – -2,029 2018-27 – -454 2018-34 - 29	2018-19 - -2,644 2018-27 - -766 2018-34 - -217	2018-19 - -2,613 2018-27 - -842 2018-34 - -321
EBITDA (Average)	2018-19 – 1.44 2018-27 – 1.45 2018-34 – 1.71	2018-19 – 1.49 2018-27 – 1.62 2018-34 - 1.88	2018-19 – 1.58 2018-27 – 1.67 2018-34 – 2.00	2018-19 – 1.59 2018-27 – 1.61 2018-34 – 1.76
Source	GRA, Appendices 3.3 & 3.5 &11.13	Interim Rate Application, Tab 1	Appendix 3.4	PUB/MH I-34, Attachment 2

4. USE OF REGULATORY ACCOUNTS

4.1 Purpose of Regulatory Accounts

The use of regulatory accounts is a common practice in the utility industry as evidenced by the fact all of the Canadian government-owned power utilities[59] denoted by KPMG as Manitoba Hydro's peers for purposes of its Financial Target Review report[60] utilize regulatory accounts.

The general purpose of regulatory accounts is to defer, for future refund or recovery, cost or revenues that would otherwise be recognized in the current accounting period for rate making purposes under the accounting practices applicable to the utility. Regulatory accounts are generally employed for one of the following purposes:

i. To better match costs and benefits for different generations of customers,
ii. To capture and defer to a future period the differences between forecast and actual costs or revenues,
iii. To smooth out the rate impact of significant non-recurring costs or smooth out rate increases, or
iv. To recover (or refund) certain uncontrollable costs or revenues associated with an uncontrollable event, where the event was not forecast in the test period used to set rates.

Regulatory accounts can either be regulatory assets (i.e., amounts potentially to be recovered from ratepayers) or regulatory liabilities (amounts potentially to be refunded to ratepayers).

With respect to the first purpose, while accounting practices allow for the cost of fixed assets to be spread out (i.e., depreciated) over the life or period of time the asset provides a benefit to customers, such is not always the case for other types of expenses. Therefore one use of regulatory accounts is to reflect timing differences between when a utility incurs expense to provide a service or acquire an asset and when the expenditure provides "benefits" to ratepayers and should be recovered. An example of this is DSM costs which accounting practices generally required be

59 BC Hydro, Hydro-Quebec, Nalcor Energy, Ontario Power Generation and NB Power
60 Appendix 4.1, page 56

expensed in the year they are incurred but which effectively serve as an alternative to constructing more generation and transmission facilities and therefore reducing future cost to ratepayers. The use of a regulatory account in such circumstances allows the cost of providing the DSM program to be properly matched with the ratepayers that will benefit from the reduced future costs.

Regulated utilities' rates are typically set using a forward looking test year and therefore require forecasts to be made for the various elements of the revenue requirement. Some elements of the revenue requirement are within the control and/or can be managed by the utility while others cannot. O&A costs would generally be considered an example of the former while examples of the latter would be the impact of weather on the test year's load or the commodity cost of electricity for a distribution utility that is simply facilitating the acquisition of the commodity on behalf of its customers. Where such items are uncontrollable and cannot be accurately forecast, errors in the forecast will result in the utility either over or under collecting the cost required which represents a risk to both the utility and to the ratepayers. This issue is particularly germane when a utility is under "rate of return" regulation and the focus of rate setting is on the test year. In such circumstances regulators frequently allow the creation of regulatory accounts to capture the differences between forecast and actual costs (or revenues).

Costs/revenues differences deferred for this reason are generally recovered over a short period of time. This is done in the interest of intergenerational equity in that the "differences" associated with the deferred costs are attributable to customers receiving service in the rate year concerned.

Regulatory accounts are also used to protect ratepayers (and utilities) from volatility in costs and revenue and windfall gains or losses. An example of this would be large one-time cost write-offs. In a similar vein, regulatory accounts are sometimes used to smooth out rate increases. Again, use of regulatory accounts for these purposes is particularly applicable when a utility is under "rate of return" regulation.

Finally, in some cases regulatory accounts are created to capture material impacts on revenue or costs arising from unique and uncontrollable events that were not foreseen at the time the rates were set. Again, use of regulatory accounts for this purpose typically occur for utilities that are under "rate of return" or performance-based regulation.

Regulatory accounts are typically requested[61] by utilities and approved for use by the regulator. Costs are then accrued in the applicable accounts. Depending upon the nature of the account, the recovery period (and basis for recovery) maybe established at the same time as the account is created or may be established through a separate application/proceeding when the utility seeks approval to include the refund/recovery of the account balance in rates.

4.2 Manitoba Hydro's Use of Regulatory Accounts

The Annual Financial Report filed[62] in conjunction with Manitoba Hydro's last GRA included regulatory accounts for the following items related to electric operations:

- Regulatory Asset Accounts
    - Power Smart Programs
    - Acquisition (Winnipeg)
    - Site Restoration
    - Regulatory
- Regulatory Liability Accounts
    - DSM Deferral

Furthermore IFF14, which was the basis for the last GRA, included[63] amortization of the balances in these Regulatory Asset accounts totalling $40.1 M for 2015/16[64]. Order 73/15 which approved Manitoba Hydro's rates for the fiscal years 2014/15 and 2015/16 did not explicitly reference the amortization of these accounts. However, the depreciation level referenced in the Order[65] was inclusive of the related amortization levels and therefore one could infer that the Board implicitly endorsed the amortization

[61] Sometimes the regulator will direct the creation of a regulatory account when it deems the need is appropriate without an application from the utility.
[62] Appendix 5.1 – 2013/14 Annual Report, pages 81 & 91
[63] PUB/MH 1-27
[64] 2015/16 & 2016/17 GRA, PUB/MH I-27. Close to $35 M was related to the amortization of Power Smart program costs
[65] Page 37

of these accounts and the associated recovery periods. It is noted that IFF14 included[66] in its forecast for 2016/17 the commencement of the amortization of the deferred costs associated with Conawapa. However, the Board's Order did not deal with 2016/17 rates.

Manitoba Hydro's Supplementary Application for Interim Rates Effective August 1, 2016 was based on IFF15 which also included amortization of these same accounts. However, as noted in the Board's subsequent Order 59/16[67] neither the forecast nor the Application complied with the Board's directives to: i) use ASL to calculate depreciation for rate-setting purposes or ii) capitalize/defer an additional $20 M in O&A costs for rate setting purposes. In the same Order the Board noted[68] that IFF15 deferred Conawapa's costs in a regulatory deferral account to be amortized over 30 years starting in 2017/18 but then observed that this assumption had no impact on the decision with respect to interim rates effective August 1, 2016 and that the matter would be dealt with at the next GRA.

The 2016/17 Annual Report filed[69] includes the preceding accounts as well as additional regulatory asset accounts for:

- Affordable Energy Fund[70]
- Loss on Disposal of Assets
- Change in Depreciation Method
- Deferred Ineligible Overhead

The initial Application for 2017/18 & 2018/19 rates included forecast amortization costs for all eight regulatory asset accounts[71] of $48.7 M and $57.7 M respectively[72]. However, in the update filed on July 11, 2017 Manitoba Hydro removed[73] the

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[66] PUB/MH I-27
[67] Pages 23 and 25
[68] Pages 24 and 26
[69] https://www.hydro.mb.ca/corporate/ar/pdf/annual_report_2016_17.pdf
[70] While the regulatory account for AEF is new, AEF was previously included on the Balance Sheet under Other Assets and the amortization is unchanged.
[71] Tab 6, Figure 6.30. While the Figure only set out amortization values for seven of the accounts it is clear from MIPG/MH I-6 b) that the amortization reported under Regulatory costs in Figure 6.30 also includes Acquisition costs.
[72] Tab 6, page 32
[73] Supplement to Tab 3, page14

amortization of the ELG/ASL differences from both years ($2.7 M and $7.3 M respectively) and deferred commencement of the amortization to 2019/20, pending the PUB review of its proposal. In addition, the financial forecast (IFF16) filed in support of the Application included the amortization of deferred Conawapa costs starting in 2019/20[74].

The current Application seeks[75] explicit endorsement by the PUB of the proposed amortization periods for the disposition of the regulatory accounts established with respect to: i) Change in Deprecation Method, ii) Deferred Ineligible Overhead and iii) the deferral and proposed amortization of the costs incurred with respect to Conawapa.

The amortization periods used in the current Application for the various regulatory asset accounts are set out in the following table. No disposition is being proposed for the regulatory liability account related to Deferred DSM Costs[76].

Schedule 19 – Regulatory Asset Accounts Amortization Periods

Regulatory Asset Account	Amortization Period
Included in Previous GRAs	
Power Smart Programs costs	10 Years
Site Restoration costs	15 Years
Regulatory costs	1 – 5 Years
Acquisition costs	30 Years
Affordable Energy Fund	Amortized as Incurred
New in Current GRA	
Loss on Disposal of Assets	20 Years
Ineligible Overheads	20 Years commencing in 2017/18. However, deferral is proposed to cease after 2022/23

[74] MIPUG/MH i-6 b)
[75] Tab 1, page 3
[76] COALITION/MH I-139 b)

ELG/ASL Depreciation Differences	20 Years commencing in 2019/20. However, deferral is proposed to cease after 2022/23
Conawapa	30 Years commencing in 2019/20

Source: Tab 3, pages 18-20, COALITION/MH I-59 and MIPUG MFR 5

4.3 Manitoba Hydro's Pre-Existing Regulatory Accounts

Three of Manitoba Hydro's pre-existing accounts (Regulatory, Power Smart Programs, and Acquisition) can be considered "benefit matching" accounts. In each case the account defers cost that will benefit customers in the future and then amortizes those costs over a period of time that is meant to match when the benefit occurs.

In the case of Regulatory costs, this is achieved by amortizing the costs over a period that matches the period addressed by the regulatory proceeding concerned[77]. The use of a period of one to five each is appropriate for most of Manitoba Hydro's regulatory proceedings (e.g., GRA's and Interim Rate Applications). However, it is apparent that some of Manitoba Hydro's regulatory proceedings are related to periods of activities that will provide benefits for well beyond 5 years. Examples would include the recent Clean Environment Commission (CEC) proceedings dealing with BP III and Keeyask as well as the PUB proceeding regarding Manitoba Hydro's recent NFAAT Application.

In cases (such as the CEC proceeding regarding BP III) where the proceeding is dealing with a specific project, it would be reasonable (and consistent with the principle of "benefit matching") to either include the cost of the proceeding as part of the overall capital cost of the project or amortize the costs over the anticipated life of the project. In other cases (such as the NFAAT Application) that dealt with an overall system plan that involved a number of projects, it would be reasonable (and again consistent with the principle of "benefit matching") to amortize the costs over the lesser of: i) the period of time the proposed system plan was addressing or ii) the period of time until the next such Application was anticipated to be presented to be presented to the regulator[78].

[77] COALITION/MH I-59 a) & b)
[78] In other jurisdictions such as BC, system plans are updated and filed on a regular basis and the cost of the associated proceedings is amortized over the period between such applications.

In the case of Power Smart costs, a ten-year period was selected as it was consistent with the period used by other Canadian utilities with similar programs[79]. While reasonable, this approach is less than ideal as the amortization period should reflect the time-frame over which Manitoba Hydro's Power Smart programs provide benefits.

In the case of Acquisition costs (related to Manitoba Hydro's acquisition of Winnipeg Hydro), a 30 year amortization period was also chosen for the Winnipeg Hydro assets to be consistent with the period previously accepted by the PUB for the Centra acquisition and which reflected the remaining life of the Centra assets[80]. Again while a more appropriate approach would have been to link the amortization period to the remaining life of the Winnipeg Hydro assets, the 30 years is likely reasonable as it approximates the remaining life of all of Manitoba Hydro's assets[81].

In contrast, the regulatory account for Site Restoration costs is meant to smooth the impact of these one-time costs over a longer period of time. In such cases, the choice of the amortization period is largely a matter of judgement.

Finally, the Affordable Energy Fund (AEF) regulatory account doesn't really fall into any of the four categories referenced earlier. The AEF was established by Provincial legislation and the account and its amortization effectively provide a mechanism whereby the spending each year is charged to operations and the fund/account is drawn down.

4.4 Assessment of Manitoba Hydro's Proposed Regulatory Account Treatment

4.4.1 Loss on Disposal of Assets

The current Application uses a 20 year amortization period and includes amortization amounts of $0.3 M and $0.6 M for 2017/18 and 2018/19 respectively. Manitoba Hydro's Application explains the treatment as follows:

> *For financial reporting purposes under IFRS, Manitoba Hydro is required to recognize gains and losses associated with the disposal of assets as an immediate charge against income. Prior to the implementation of IFRS, Manitoba*

[79] 2014/15 & 2015/16 GRA, COALITION/MH I-49 d)
[80] COALITION/MH I-59 a) & b)
[81] PUB/MH II 1a & b)

> *Hydro deferred the recognition of gains and losses on the disposal of assets by recognizing the gains or losses within accumulated depreciation. The balances were included as an adjustment to future depreciation rates (as determined in formal depreciation studies) and as such, gains and losses were recognized over the remaining service life of the assets. For rate-setting purposes, Manitoba Hydro is continuing to defer gains and losses on the disposition of assets, consistent with the direction provided by the Public Utilities Board in Order 73/15. Gains and losses on the disposal of assets are initially recorded in Depreciation and Amortization expense and are offset within the Net Movement in Regulatory Deferral Account. Effectively, this accounting treatment defers the gains and losses in a regulatory deferral account which is then subsequently amortized over a 20 year period.*

While Order 73/15 references[82] this change in the accounting treatment of Loss on Disposal of Assets, there are no explicit Board directions in the Order either denying or accepting the regulatory asset treatment outlined by Manitoba Hydro. At best one can infer that, by not rejecting the proposal to defer and amortize these costs the Board has implicitly endorsed it.

Overall, it appears that the purpose of deferring Losses on Disposal of Assets is not to improve intergenerational equity since the losses (or gains) are experienced when assets are retired earlier or later than expected and therefore are associated with benefits the retired assets have already provided. Rather the purpose appears to be to smooth out the impact of these one-time costs. As noted earlier, in such situations the choice of amortization period is a matter of judgement. Since an amortization period of 20 years is likely to achieve a result similar to that experienced prior to the implementation of IFRS[83], the period appears reasonable.

[82] Page 4

[83] Given average expected service life of 34 years (2016/17 Supplemental Filing, Attachment 28) it is reasonable to assume that the remaining service life of the assets would be roughly ½ or roughly 20 years.

4.4.2 Ineligible Overheads

The account captures the roughly $20 M in ineligible overheads arising from the Board's Order 73/15[84]. In that Order the Board did not accept the higher levels of OM&A costs (relative to those identified in previous proceedings) that Manitoba Hydro proposed would be expensed as a result of changes the Corporation had made to its integrated corporate cost allocation methodology and overhead rates in compliance with IFRS. In a subsequent letter[85] to the Board, Manitoba Hydro sought clarification regarding the accounting treatment that would be consistent with the Board's Order. In its reply[86], the Board indicated that its mandate was to prescribe appropriate accounting for rate setting purposes and, in that regard, the treatment of ineligible overheads as set out Attachment 46-Scenario 2 filed in with the recent Application for interim rates effective August 1, 2016 was consistent with intent of Order 73/15. In that Scenario, the treatment of ineligible overheads is as follows:

i. $20 M of OM&A expense is deferred and amortized over 30 years
ii. The amortization is done through other comprehensive income.

In contrast, Manitoba Hydro's current proposal is to amortize the deferred amounts over 20 years and to cease deferring such costs as of March 31, 2023[87]. In addition, Manitoba Hydro proposes to amortize the regulatory account through net income.

Overall there are three issues the Board needs to consider: i) the appropriate amortization period for the regulatory account, ii) whether the deferral should cease effective March 31, 2023 and iii) whether the account should be amortized through net income or other comprehensive income – recalling that the determination of these issues is for regulatory (and not financial) accounting purposes. For 2017/18 and 2018/19 the amortization amounts are $1.8 M and $4.5 M respectively[88].

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[84] Page 35
[85] Appendix 10.9
[86] Appendix 10.9, page 3
[87] Tab 3, page 19
[88] Tab 6, page 42

In Order 73/15 the Board directed[89] that the $20 M difference "continue to be capitalized as per existing practices". Under existing practice, these OM&A cost were capitalized and included in the costs of projects under construction and, as result, eventually recovered through depreciation charges associated with the assets once they were declared in-service. A comparable treatment would see the costs amortized over a period approximating the average life of Manitoba Hydro's assets which is likely considerably longer than either the 20 years proposed by Manitoba Hydro or the 30 years set out by the Board in Attachment 46[90]. Also, given that depreciation charges are amortized through (i.e., impact) net income it would be appropriate for the amortization of Ineligible Overheads be treated in a similar manner.

Manitoba Hydro's proposals to amortize this account over 20 years and to cease deferring the costs after 2022/23 appear to be based on the concern regarding the potential growth in regulatory account balances and, more specifically, those associated with ineligible overhead and depreciation deferral[91].

This concern about the growth in regulatory account balances was first raised during the review of Manitoba Hydro's Supplementary Filing for 2016/17[92]. At that time, Manitoba Hydro expressed the view that this treatment led to intergenerational inequity in that the burden of recovery was being pushed out to future ratepayers. In doing so Manitoba Hydro referenced a report by the BC Auditor General that expressed concerns about the high level of BC Hydro's regulatory asset balance and the view that "over used rate regulated deferral can mask the true cost of doing business, distort the financial condition of an enterprise and place undue burden on future rate payers". However, there are few points of clarification that need to be made in regards Manitoba Hydro's statement and the relevancy of the BC Auditor General's Report.

First, in Attachment 28 of the 2016/17 Supplemental Filing, Manitoba Hydro suggests that there is an equivalency between its situation of potentially $1.9 B in regulatory assets in 2035 and BC Hydro's $2.2 B regulatory asset balance at the time of the

[89] Page 36
[90] This observation is based on the fact that the current estimate as to the remaining life of Manitoba Hydro's existing assets is 34 years - 2016/17 Supplemental Filing, Attachment 28
[91] Tab 3, pages 10-20.
[92] Attachment 28

Report. The following table sets out the net regulatory balance for BC Hydro at the time report (2011), the most recent net regulatory balances for Manitoba Hydro and the other Canadian utilities referenced earlier (including BC Hydro) and finally the Scenario from Attachment 28 that gives rise to the $1.9 B in regulatory assets in 2035. In each case these balances are compared to the total assets for the utility.

Schedule 20 – Canadian Utilities' Regulatory Assets ($M)

UTILITY	Regulatory Asset Balance	Regulatory Liability Balance	Net Regulatory Account Balances	Total Assets	Net Balance / Total Assets
BC Hydro (2011)	2,436	276	2,160	19,479	11.1%
BC Hydro (2017)	6,127	530	5,597	31,888	17.6%
Hydro Quebec (2016)	4,360	381	3,979	75,167	5.3%
OPG (2016)	5,855	310	5,455	44,372	12.5%
NB Power (2017)	1,009	0	1,009	6,968	14.5%
Nalcor (2016)	164	348	- 184	14,062	- 1.3%
Manitoba Hydro (2017)	566	77	489	22,338	2.2%
Manitoba Hydro – Electric (2035 – Attach 28)	1,888	0	1,888	35,560	5.3%

Sources: Annual Financial Reports

As can be readily seen, as a percentage of total assets, Manitoba Hydro's current net regulatory account balance is one of the lowest amongst its peers and, even under the regulatory account treatment specified in Attachment 28, its 2035 net regulatory account balance would still be low compared to other utilities. The point is that when it comes to regulatory asset balances Manitoba Hydro's position now, and even if the regulatory asset deferrals continues in the future, are not on the same scale as BC Hydro's.

The second point is that in 2011 almost 40%[93] of BC Hydro's total regulatory asset account balance was associated with regulatory accounts where the purpose was to defer to a future period the differences between forecast and actual costs or revenues for items such as purchased energy costs and fuel costs and/or to defer costs for purposes of rate smoothing. It is in these situations that the costs being deferred are

[93] BC Hydro, 2015-2016 Revenue Requirements Application, Appendix H, page 32 of 79

most clearly those associated with serving and benefiting current period customers and where deferring cost recovery raises the most concern regarding intergenerational equity. In contrast, regulatory accounts such as those associated with Power Smart and Regulatory costs are aimed at matching benefits and costs and therefore enhance intergenerational equity.

Manitoba Hydro's comments suggest that the Board's decision to defer ineligible overheads (and ELG/ASL depreciation differences) was based on rate smoothing considerations. However, it is not clear that this was the case. In the case of ineligible overheads, the Board's Decision appears to reflect a view that the level of overheads identified in the proceeding prior to the 2015/16 and 2016/17 GRA were the appropriate level to capitalize for rate-setting purposes. However, at the end of the day, it remains for the Board to confirm what its objective was in deferring the $20 M of ineligible overheads. If the Board was/is of the view that the $20 M is more appropriately capitalized, then there is no basis for ceasing the deferral after 2022/23.

4.4.3 ELG/ASL Depreciation Differences

Manitoba Hydro's current proposal[94] is to amortize the ELG/ASL[95] Depreciation difference over 20 years starting in 2019/20 and to cease deferring the difference in costs after 2022/23.

In the case of the ELG/ASL Depreciation difference, it is clear from Order 43/13[96] that the Board was not convinced that ELG was the appropriate method of depreciation for rate setting purposes. In that Decision the Board directed[97] Manitoba Hydro to provide additional information in its next GRA regarding IFRS-compliant ASL depreciation rates and a comparison of the impacts on its Integrated Financial Forecast of using these ASL-based depreciation rates versus depreciation rates based on the ELG methodology. Manitoba Hydro filed additional information as part of its Supplementary Application for Interim Rates Effective August 1, 2016. However, the Board considered this information to be insufficient to make a decision regarding the use of ASL vs. ELG-

[94] Supplement to Tab 3, page 14
[95] The terms ELG and ASL refer to Equal Life Group and Average Service Life methods of depreciation
[96] Pages 18-19
[97] Directives 8 & 9

based depreciation rates[98] and directed Manitoba Hydro to continue to use ASL for rate-setting purposes. At the same time, the PUB indicated that it was not rejecting ELG outright but rather required additional information prior to making a decision on ASL vs. ELG and (again) directed Manitoba Hydro to file additional information at its next GRA. In the meantime Manitoba Hydro was directed to continue to use ASL based on CGAAP (ASL-CGAAP) for rate setting purposes[99].

Both ASL (albeit a more refined methodology than currently used by Manitoba Hydro) and ELG are appropriate under IFRS[100]. Furthermore, under either ASL or ELG Manitoba Hydro eventually recovers through depreciation the entire cost of its assets[101]. As a result, from a cost matching perspective, there is no reason to introduce a regulatory account. The need for a regulatory account arises from the fact that if Manitoba Hydro utilizes a different depreciation method for rate setting than it does for financial reporting then, in order to be compliant with IFRS, it would need to either: i) keep two set of books or ii) create a regulatory account so that the difference can be captured in its financial statements. In the past Manitoba Hydro has argued that keeping two set of books would be overly expensive and impractical given the number of transactions it records through its financial systems and that a regulatory account is the more practical approach[102].

Manitoba Hydro's rationale for amortizing the difference between ELG and ASL depreciation is that while there is cross-over point between ELG and ASL it will not occur until beyond the 20 years of the current financial forecast. In its view this is too long a time period, in that the balance account will continue to grow and, as noted previously, place inappropriate burden on future ratepayers[103].

Furthermore, Manitoba Hydro contends that if the PUB did not permit the recovery of the difference in depreciation expense between the ELG and ASL-CGAAP methodologies, Manitoba Hydro understands that it would not be permitted to maintain

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[98] Order 73/15, page 46
[99] Order 73/15, page 97
[100] Order 73/15, page 39
[101] Order 73/15, page 45 and COALITION/MH I-138 a) & b)
[102] PUB/MH I-1 d)
[103] COALITION/MH I-138 and MIPUG/MH I-6 j)

a regulatory deferral account per the requirements of IFRS 14. It has also expressed concern that the regulatory account balances will grow to an excessive amount such that the auditors will become concerned and need to be written off[104].

For these reasons Manitoba Hydro has proposed that the amortization period be 20 years and that the deferral cease after 2022/23. The rationale for this date is that it coincides with the final in-service date for the Keeyask generating station and that annual increases in export sales made possible by the capacity of the Keeyask plant will be more than sufficient to offset annual increases in depreciation resulting from the impacts of the transition to IFRS (i.e., ELG)[105].

There are problems with Manitoba Hydro's proposal and its supporting rationale. First, as already discussed, Manitoba Hydro's situation with respect to its regulatory account balances is materially different from that of BC Hydro, with which Manitoba Hydro is making comparisons. Indeed, when compared to its peers (and particularly BC Hydro), Manitoba Hydro's regulatory balances are small and will continue to be small in comparison even if the ELG/ASL Depreciation Difference account is deferred indefinitely and amortized over a longer period of time or not amortized at all[106].

Second, while in principle there is no need for amortization of the account for purposes of "benefit matching" if amortization is required then, based on this principle, a more appropriate period would be the remaining service life of its assets or 34 years.

Third, the 2022/23 date for ceasing further deferrals is problematic. It assumes that the initial reason the Board had for directing that ASL-CGAAP continue to be used was for rate smoothing purposes. However, it is clear from the Board's Decisions that the issue was one of which methodology, ASL (IFRS compliant) or ELG was most appropriate for rate-making purposes.

Also, the 2022/23 date was based on IFF16 which foresaw the 7.9% annual rate increases ceasing around that time. However, with the IFF16 Update and Interim Rate decision, Manitoba Hydro is now projecting that rate increases well in excess of inflation

[104] Supplementary Application for Interim Rates effective August 1, 2016, Attachment 28
[105] MIPUG/MH I-6 i)
[106] PUB/MH I-1 d)

will be needed until 2024/25[107]. Ceasing the deferral after 2022/23 means that both the full ELG depreciation plus continued recovery of the ELG/ASL differences differed to date will be expensed in the years immediately after and reduce the ability of the 7.9% increases to contribute towards net income and debt ratio improvement.

Finally, Manitoba Hydro's response[108] to the Board's directives regarding the depreciation methodology to be used for rate setting does not explicitly indicate when (or even if) the Corporation plans to provide the additional information directed by the PUB. The PUB has made it clear that ASL-CGAAP is to be used until such information is provided and a decision is made as to whether ASL (IFRS compliant) or ELG is to be used for rate-setting purposes. Assuming Manitoba Hydro intends to comply with the Board's directive and to do so prior to 2022/23, a reasonable course of action would be to not amortize the associated regulatory account balance until a decision is reached regarding the appropriate depreciation method to be used for rate-setting. At that time the implications of the change in depreciation methodology will be better understood and an appropriate amortization period can be established. This approach is similar to the one Manitoba Hydro is taking in regards to the DSM deferral account where it is awaiting further information and direction before clearing the account[109].

4.4.4 Conawapa

Manitoba Hydro's current proposal is to commence amortization of the $380 M in deferred Conawapa cost over 20 years starting in 2019/20[110]. The purpose in deferring these costs is "rate smoothing" and, as such, the selection of the amortization period is a matter of judgement recognizing both the need to recover the costs and their impacts on rates. In the case of Conawapa a fairly long recovery period is justified on the grounds that the cost are significant (i.e., over 23% of Manitoba Hydro currently forecast domestic revenues for 2017/18[111]). Furthermore, the "write-off" was triggered by the PUB's decision regarding Manitoba Hydro's Proposed Development Plan as put forward in its NFAAT Application. Since the decision dealt with the most appropriate way to

[107] Appendix 3.8
[108] Tab 10, page 7
[109] COALITION/MH I-139 b)
[110] Tab 3, pages 18- 19 and COALITION/MH I-105.
[111] Appendix 3.8

meet Manitoba Hydro's energy needs over a long-term planning horizon, the write-off can be viewed as part of the overall cost of implementing the Board's decision. Overall, the 20 year period is reasonable.

4.4.5 Conclusions

Manitoba Hydro is seeking endorsement for its proposed treatment of four regulatory accounts. Manitoba Hydro's proposed treatment for both the Loss on Disposal and Conawapa regulatory accounts is reasonable. However, as discussed above, the Board should not endorse Manitoba Hydro's proposal regarding the Ineligible Overheads or ELG/ASL Differences accounts. In the case of the Ineligible Overheads account the amounts should be amortized over at least 30 years and, pending clarification from the Board, the deferral should not be ceased after 2022/23. In the case of the ELG/ASL Differences account, the Board should not endorse any amortization of this account until Manitoba Hydro has addressed the Board's outstanding directives on the matter and a final decision has been made as to the appropriate depreciation method for regulatory purposes.

5. MANITOBA HYDRO'S COST OF SERVICE STUDY (COSS)

Manitoba Hydro's 2017/18 & 2018/19 General Rate Application (GRA) includes the implementation of the Board's findings and directives in Order 164/16 flowing from the recent Cost of Service Methodology Review completed by the Board. This section of the Evidence reviews the COSS filed by Manitoba Hydro (PCOSS18) and looks at whether it has complied with the Board's directives and findings. It then looks at some of the implications for the current GRA in terms of the Zone of Reasonableness to be used in applying results and the role of the results in the overall rate making process.

To provide some context, this discussion in prefaced by a brief review of the purpose of the COSS and a summary of some of the principles and broad findings set out in Order 164/16. Key among these in considering the implementation of the Board's Directives and the subsequent use of the COSS results are the Board's conclusions that:

- *[I]in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage*[112]*.*
- *While the results of a COSS appear to be arithmetically exact, a COSS involves considerable judgment. There is no single industry standard that applies to all COSS decisions*[113]*.*
- *[O]other ratemaking principles for setting just and reasonable rates should be considered in a GRA, and not a cost of service process*[114]*.*

5.1 Background

5.1.1 Purpose of a Cost of Service Study

The determination of a utility's rates can be viewed as a two stage process. The first stage focuses on the determination of the overall revenue requirement that the utility will be allowed in the test (or rate) year or, put another way, the overall rate level. At this stage consideration is given to the reasonableness of the forecast of customer energy and peak load that the utility will be expected to supply along with associated costs,

112 Page 29
113 Page 5
114 Page 6

including the return on investors' capital where applicable. When it comes to these costs the focus is on whether the costs are necessary, reasonable and prudently incurred in order to provide the utility's customers with safe and reliable service.

The second stage is the "rate making stage" where the individual rate schedules for the utility's customers are determined such that they will (collectively) cover the revenue requirement. Rate making itself also consists of two steps. The first is establishing the portion of the total revenue requirement to be recovered from each rate class while the second step involves establishing the rate schedule(s) for each customer class that will return the class' share of the revenue requirement. The purpose of a cost of service study is linked to the first of these two steps and involves establishing a method for assigning/allocating the pre-established total revenue requirement amongst the utility's customer classes. Once the results of the Cost of Service Study are known they can be used as an input into designing customers' electricity rates.

Cost of service studies generally employ a three-step process of cost analysis:

1) <u>Functionalization:</u> In some cases assets and/or services are used by only one customer class and can be directly assigned to that class. But the majority of a utility's assets and activities support a number of customer classes and the first step is to functionalize the assets and annual expenses (including the cost of capital) according to the services (or functions) the utility provides such as production, transmission, distribution and customer service.
   However, these functions are frequently broken down further to capture specific activities either used by different customers or having different cost drivers. It should be noted that functionalization applies not only to a utility's "costs" but also to the other revenues included in the revenue requirement which serve to reduce the costs that need to be recovered through customers' rates.
2) <u>Classification:</u> Each function's costs are then classified according to the system design or operating characteristics that caused those costs to be incurred. In the case of electric utilities, costs are generally classified as one of three types: demand costs incurred to meet a customer's maximum instantaneous power requirements (i.e., demand or capacity); energy costs incurred to provide

customers with electricity over a period of time; and, customer costs incurred to carry customers on the system.

3) Allocation: Finally each functionalized and classified cost component is allocated to specific customer classes based on each class' contribution to the specific cost driver selected.

The ratio of the revenues that are to be collected from each customer class (assuming no rate rebalancing) to the costs allocated to each class as per the cost of service study is called the revenue to cost ratio (R/C ratio). A R/C ratio that is close to 1.00 (or 100%) is considered to mean that the customer class is paying its fair share of costs. If the ratio exceeds 1.0 by a large enough margin, the class may be considered to be paying more than its fair share of costs. Alternatively, if the revenue to cost ratio for a customer class is significantly below 1.0, it may indicate that the costs imposed on the system by the class are not being recovered fairly from that class.

Cost of service studies are, by necessity, not a precise analysis. They frequently involve choices between methodologies in terms of how the cost of shared facilities and activities should be allocated to customer classes, rely on simplifying assumptions and utilize sample data. This has led to the practice of establishing revenue to cost ratio ranges within which it is considered that a customer class is paying its fair share of costs. These ranges are referred to as zones of reasonableness ("ZOR").

5.1.2 PUB Order 164/16

On December 4, 2015 Manitoba Hydro filed an Application with the Manitoba Public Utilities Board for review and consideration of its Cost of Service methodology. Following an extensive proceeding that involved information requests, technical conferences, and an oral hearing, the PUB issued Order164/16 in which it provided direction to Manitoba Hydro as to the methodology to be used in preparing its next Cost of Service Study (COSS). The following sections of this evidence deal with Board's specific recommendations regarding methodology. However, before dealing with them, it is useful to highlight some of the principles and observations set out in the Board's Order that underpin its findings and their subsequent use which are set out below.

COSS Objectives

- *The Board accepts and applies the principle of cost causation in establishing the appropriate method of allocating Manitoba Hydro's financial costs to the various customer classes* (page 6).
- *The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage* (page 27).
- *[T]he Board determines that, in part, the creation of the Export class was based on ratemaking goals and not cost of service principles. As discussed above, Manitoba Hydro's purpose for including an Export class in the COSS is to achieve fairness and equity between the rates paid by domestic customer classes. The Board's view is that these concerns are more appropriately considered and, if necessary, addressed in the context of ratemaking in a GRA* (page 32).
- *[C]ost causation underpins the COSS methodology, without including other ratemaking goals. Equity and efficiency are ratemaking goals that should be addressed in a rate-setting process such as a GRA* (page 53).

Basis for Cost Causality

- *Cost causation as defined by the Board takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro's current system planning, as well as the current use. This methodology is to apply to assets currently in service, as well as future assets, such as Keeyask and Bipole III. The Board also finds that cost causation requires consideration of all the uses and benefits of an asset, to recognize that both primary and secondary benefits influence the planning and justification of assets. These considerations should be assessed over a range of years (as opposed to a single forecasted year) and over a range of conditions in order to capture all of the uses and benefits of an asset in determining cost causation* (page 27).
- *While the results of a COSS appear to be arithmetically exact, a COSS involves considerable judgment. There is no single industry standard that applies to all COSS decisions* (page 5).

- *The Board rejects the equivalent peaker methodology as too complex and open to continuing argument over the appropriate costs to be used in its calculation. The Board directs the use of the system load factor because it is straight-forward and generally accepted in the industry. System load factor has a clear cost causation basis as it reflects the factors considered by resource planners when deciding the types of generation resources to add to the system* (page 48).

Role in Rate-Making

- *The objective in designing a COSS is to select a cost allocation method for sharing of costs. A COSS neither determines nor changes rates but may assist in rate setting by evaluating whether customer classes pay their appropriate share of costs through rates* (page 18).
- *The Board finds that other ratemaking principles for setting just and reasonable rates should be considered in a GRA, and not a cost of service process. A COSS neither determines nor changes rates, but may assist in rate setting and in evaluating whether customer classes pay their appropriate share of costs through rates* (page 6).
- *This Order does not establish Manitoba Hydro's Revenue Requirement or rates for domestic or export customers. Domestic rates are established through a GRA where the Board approves Manitoba Hydro's Revenue Requirement. Using the tools available to the Board, including the approved COSS, the Board then reviews and approves Manitoba Hydro's rate design and establishes the resulting rates. In setting domestic electricity rates, the Board has discretion as to what, if any, use is made of the COSS* (page 16).
- *[M]any utilities and their regulators, including Manitoba Hydro and the Board, recognize a zone of reasonableness within which the utility is to target the RCC ratios of its customer classes. Manitoba Hydro's zone of reasonableness is currently 0.95 to 1.05, meaning that Manitoba Hydro considers it reasonable when a customer class's rates are set to recover between 95% and 105% of the costs allocated to that*

*class in the COSS. RCC[115]s and the zone of reasonableness are rate design issues that are addressed in the context of a GRA (*page 24)*.*

- *There is no cost causation basis for deducting the URA[116] from export revenue, nor does the legislation require such an approach. Any impacts of the Board's COSS treatment of uniform rates on RCC ratios are a matter for consideration in rate design, not cost of service* (page 41)*.*
- *The Board finds that the assets in the Diesel zone are not causally linked to the realization of export revenues. Therefore, there is no cost causation basis for the crediting of any export revenues to the Diesel class. As previously noted, any resulting need to make adjustments to rates should be raised in a rate-setting process* (page 41)*.*

The key takeaways to be considered when assessing Manitoba Hydro's follow-up to the Board Order and its use of the COSS results in the current Application appear to be:

i. Cost causation is the sole principle that should be used in establishing the appropriate COSS methodology. Other rate-making objectives such as efficiency and rate stability as well as public policy and public interest considerations are not to play a role.
ii. There is no generally accepted methodology or industry standard when it comes to the appropriate COSS methodology.
iii. While cost causation is paramount in determining the appropriate COSS methodology, practical matters such as acceptability and understandability also come into play. Also, establishing the appropriate cost of service methodology involves judgement and the results are not as arithmetically precise as they appear.
iv. The results of the cost of service study do not define the revenue requirement by customer class for rate setting purposes nor do they define the rate structure to be used. Rather they are an input into such determinations along with other rate-

[115] RCC refers to Revenue Cost Coverage and is the same that Revenue to Cost Ratio discussed earlier.
[116] Refers to the Uniform Rate Adjustment. It reflects the financial and COSS impact of the introduction (by way of legislation) of uniform rates for all grid-connected customer customers.

making objectives/considerations such as efficiency, rate stability and public acceptability.

5.1.3 Order 164/14 – Manitoba Hydro's Compliance Filing

One of the directives in Order 164/16 was that Manitoba Hydro provide a "compliance filing" within 60 days of the Order which was to include a revised version of PCOSS14-Amended that reflected all of the Board's findings and directions. This compliance filing was provided to the Board on February 21, 2017. On April 4, 2017 the Board wrote to both Manitoba Hydro and intervenors to the COSS Methodology Review proceeding providing its comments regarding the compliance filing and soliciting comments from other parties. Subsequently ECS assisted the COALITION in reviewing and preparing comments on the compliance filing. These comments were forwarded to the Board on April 28, 2017 and are attached as Appendix B.

The extent to which the COSS study filed with the current Application addresses the issues raised by the Board and those noted in the COALITION's correspondence is also dealt with in the following sections.

5.2 Manitoba Hydro's Current COSS Model (PCOSS18)

5.2.1 Functions Used in PCOSS18

Manitoba Hydro's PCOSS18 functionalizes the utility's costs into five primary functions prescribed in Order 164/16[117]: Generation, Transmission, Subtransmission, Distribution Plant and Distribution Services (or Customer Services). It also directly assigns/functionalizes certain costs to the Area & Roadway Lighting and Diesel customer classes.

In some cases the costs are further sub-functionalized in order to facilitate their allocation to customer classes. This occurs in the following cases:

- Transmission, which is sub-functionalized to separate out US Interconnections[118].
- Distribution Plant, which is further sub-functionalized into Substations, Transformer, Poles & Wires, Services and Meters[119].

[117] Order 164/16 prescribed the methodology to be used to assign Manitoba Hydro's cost to one of these five functions.
[118] Tab 8, page 10

- Distribution Services, which is further sub-functionalized into General Customer Service, Other Customer Service-Small Customers, Industrial and Commercial Solutions, Customer Billing, Collections, Inspections and Meter Reading[120].

The sub-functions used by Manitoba Hydro are consistent with the Board's COSS methodology as prescribed in Order 164/16[121].

5.2.2 Revenues and Expenses Used in PCOSS18

The Cost of Service Study provided in the current Application – PCOSS18 - uses the revenues and expenses for 2017/18 flowing from IFF16[122].

Revenues

The total Revenues of $2,022 M as reported in IFF16 are adjusted as follows:

- Remove the $88 M attributed to the general rate increase of 7.9% included in the forecast[123].
- Remove from the BP III deferral account transfer the portion attributable to the general rate increase ($6 M)[124].
- Assign Late Payment & Customer Adjustment revenues to individual customer classes ($5.7 M).
- Include in Export Revenues: i) $816 k in retail sales revenues from customers outside of Manitoba initially included in Domestic Revenues and ii) $129 k in revenues from Ontario Power Generation for energy that was generated on the Winnipeg River in Manitoba using water from the Lake St. Joseph - Root River Diversion initially included in Other Revenue.
- Assign the balance of Other Revenue ($30.2 M) as follows: i) categorize Amortization of Contributions in Aid of Construction ($10.7 M) as Depreciation and functionalize by matching to base for contributions[125], ii) categorize Joint Use Revenues ($4.8 M) as an Operating Expense offset and functionalize as

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[119] Tab 8, page 6
[120] Tab8, page 12
[121] Pages 70 & 79
[122] Tab 8, page 3
[123] PUB/MH I-132
[124] PUB/MH I-138
[125] PUB/MH I-145

Distribution-Lines (i.e., Poles & Wires), iii) categorize Permit Inspection Fees ($2 M) as an Operating Expense offset and functionalize as Distribution Services-Inspection, and iv) categorize the remaining Other Revenue ($12.8 M) as an Operating expense offset and allocate to all functions using the COSS labour allocator[126].

The result is $1,455.2 M in General Consumer Revenues and $455.1 M in Export Revenues for a total of $1,910.3 M[127].

In Order 164/16 the only aspect of the adjustments that Manitoba Hydro had proposed with respect to Revenues that the Board commented on was the treatment of Late Payment and Customer Adjustments which it directed be "allocated based on the share of late payment revenue that was collected from each respective class"[128]. In its compliance filling Manitoba Hydro noted that while it could readily identify the Late Payment Revenue attributable to the Residential class the amounts specific to the remaining customer classes was not readily available. Based on this information 81% of the forecast revenue was assigned to the Residential class. However, the remaining 19% was allocated to the other customer classes (with the exception of the GSL classes over 30 kV[129]) on the basis of each customer class' forecast revenue.

The only issue in this regard that the Board raised in is subsequent response to the compliance filing was to note a small discrepancy between the results in the compliance filing and those available during the COSS Review. In response to interrogatories Manitoba Hydro has provided work sheets[130] demonstrating that the Late Payment Revenue allocation in PCOSS18 is consistent with its proposed implementation of the Board's directive.

Overall, the approach adopted by Manitoba Hydro is reasonable given the data limitations. However, parties need to be mindful of this and other model simplifications

[126] PUB/MH I-145
[127] Tab 8, Schedule 6.1
[128] Directive 1 (bb), page 96
[129] This exception was made on the basis that there is little or no late payment revenue typically associated with these classes.
[130] PUB/MH I-155

when considering the appropriate zone of reasonableness to be used when interpreting/applying the results of Manitoba Hydro's COSS.

Expenses

For purposes of the COSS, the various expense components of the Revenue Requirement are categorized as Interest, Depreciation or Operating costs and then assigned to functions. The following schedule sets out the categorization of the Revenue Requirement per PCOSS18 and the basis for functionalization of each element.

Manitoba Hydro's financial reporting system (SAP) tracks O&A and depreciation expense using approximately 400 "cost centres". The vast majority of these cost centres are facility based and sufficiently disaggregated that the costs can be directly assigned to one of the functions and, subsequently, sub-functions employed by the COSS. However, this is not always the case which gives rise to the concept of "common costs".

Schedule 21

COST CATEGORIZATION OF REVENUE REQUIREMENT - PCOSS18

Cost Element	Total	Interest	Depreciation	Operating	Basis for Functionalization
	($M)				
O&A	518.3			518.3	Combination of Direct,
					SAP & COSS Labour Allocators
Finance Expense	574	574			
Finance Income	-15.8	-15.8			
Depreciation &	396.1		384.6	12.5	Combination of Direct,
Amortization					SAP & COSS Labour Allocators
Water Rentals &	124.1			124.1	Direct
Assessments					
Fuel and Purchased	135.4			135.4	Direct
Power					
Taxes					
- Capital	92.8	92.8			Rate Base
- Payroll	12.7			12.7	SAP Labour Allocator
- Property Tax - Admin	9.1			9.1	SAP Labour Allocator
- Property Tax - Plant	17.1			17.1	Actual Assessments
Other Expenses					
- Power Smart	55.7				Deferred to NM
- Regulatory	3.6				Deferred to NM
- Site Restoration	2.8				Deferred to NM
- Restructuring	50.4			50.4	COS Labour Allocator
- Other	2			2	COS Labour Allocator
Corporate Alloc.					
- Depreciation	1.4		1.4		COS Labour Allocator
- Finance	6.5	6.5			Rate Base
- Write-Down Amort.	0.5		0.4		COS Labour Allocator
Net Movement					
Additions					
- Power Smart	-55.7				Offset by Deferral
- Site Restoration	-3.6				Offset by Deferral
- Regulatory	-2.8				Offset by Deferral
- Deferred OHs	-20.2			-20.2	SAP Labour Allocator
- ELG/ASL Difference	-34		-34		Tracked by Asset Class
Amortization					
- Power Smart	35.7		35.7		Direct
- AEF	0.4		0.4		Direct
- Site Restoration	4.1		4.1		Diesel - Direct &
					Balance - COSS Labour Allocator
-Regulatory	3.6		3.6		Hearings - Direct &
					Acquistion - COSS Labour Allocator
-ELG/ASL Difference	2.7		2.7		Tracked by Asset Class
- Loss on Disposal	0.3		0.3		Tracked by Asset Class
- Deferred OHs	1.8		1.8		COSS Labour Allocator
Net Income	21	21			Rate Base
Other Revenue					
- CIAC Amort	-10.7		-10.7		Direct
- Joint Use Poles	-4.8			-4.8	Direct
- Inspection Fees	-2			-2	Direct
-Balance	-12.8			-12.8	SAP Labour Allocator
TOTAL	1909.7	678.5	390.3	841.8	

Sources: COALITION/MH I-229, 232,233,234,235,236 & 246; COALITION/MH II-29, 51 &76 and PUB/MH I-140 & 145

Treatment of Common Costs

There are actually three contexts in which "common costs" arise in the COSS methodology. The first is with respect to cost centres in Manitoba Hydro's financial reporting system that support line functions involved directly in providing electricity and customer service[131]. Examples of this are human resources and payroll. In these cases the financial reporting system itself uses an internal allocator based on labour costs (referred to as the "SAP Labour Allocator") to allocate the costs in these cost centres to facility and customer service related cost centres which are then functionalized. As a result, there is no need to explicitly functionalize or sub-functionalize these common costs[132].

The second context in which "common costs" arise is with respect to the SAP cost centres for Buildings & General Equipment and Communication & Control Systems. These are facility-based cost centres but they are ones that provide support/service for the COSS functions and their costs must be allocated appropriately. Order 164/16 addresses this issue in the following Directives[133]:

- 1 (cc) - Buildings and General common costs shall be functionalized across all functions using Manitoba Hydro's labour allocator;
- 1 (dd) - Communication and Control common costs shall be functionalized by the labour allocator and the SCADA allocator;
- 1 (ee) - Manitoba Hydro shall update the 36/28/36 factors for functionalization of SCADA common costs;

The Manitoba Hydro COSS Labour Allocator referred to in Directive 1 (cc) is based on the total operating cost for each function (excluding water rentals, fuel and power purchases) as discussed during the COSS Review proceeding. Manitoba Hydro has reconciled[134] the total operating costs by function it uses for purposes of its COSS Labour Allocator with total operating costs allocated to each function in the COSS study

[131] Appendix 8.1, page 11
[132] Tab 8.1, page 12
[133] Pages 96 & 97
[134] PUB/MH I-156, COALITION/MH I-237 a)-c) and COALITION/MH II-30

and, in doing so, confirmed that, for each function, the operating costs excluded from the allocator are[135]:

- Fuel and Purchased Power,
- Water Rentals and Assessments (e.g. MISO fees),
- Buildings & General Equipment Operating Costs, and
- Communications & Control Systems Operating Costs.

With respect to Directive 1 (ee), Manitoba Hydro has proposed a new approach whereby the SCADA-related costs are allocated to functions based on the total number of remote terminal units installed by function[136]. This approach is reasonable as the number of remote terminal units by function provides a measure of the relative use each function makes the control system.

In its comments regarding Manitoba Hydro's February 2017 compliance filing the Coalition noted that there were insufficient details to determine if the functionalization of the depreciation and operating costs associated with Communication and Control Systems complied with the Board's directives. A similar issue existed with PCOSS18 as filed with the Application. In response to information requests[137], Manitoba Hydro has addressed this matter. In future filings it would be useful if Manitoba Hydro provided supporting documentation on all allocations made outside of it financial reporting system for purposes of the COSS as part of the COSS model details.

For PCOSS18, Manitoba Hydro has changed the allocation of Buildings and General Equipment as it applies to Diesel. PCOSS14 directly assigned a small amount of the Buildings' rate base to Diesel but none of the General Equipment rate base. For PCOSS18 this was changed such that the COSS Labour Allocator is now used to also allocate the rate bases for Buildings and General Equipment to Diesel, consistent with allocation approach used for other functions[138].

[135] The last two being the cost categories the allocator is applied to.
[136] Tab 8, page 8
[137] COALITION/MH I-239
[138] COALITION/MH II-31 a) & b)

Order 164/16 also dealt with how this second category[139] of "common costs" would be allocated to customer classes in the following Directives:

- 1 (ff) - Common costs within each function shall be allocated to customer classes based on the cost-weighted average of all the allocators within each function; and
- 1 (gg) - Manitoba Hydro shall study the allocation of common costs and develop allocators that are more directly related to the causes of the common costs.

In PCOSS18 Manitoba Hydro has followed Directive 1 (ff) in allocating the second category of "common costs"

The third context in which the term "common costs" is used is in the characterization of certain cost centres that can be associated with specific functions but cannot be attributed to specific facilities within the function[140]. For example, the $23 M in Transmission-Common costs is related to activities such as transmission R&D, transmission planning and system protection[141]. In PCOSS18 Manitoba Hydro has also applied Directive 1 (ff) in allocating this third category of common costs[142] to customers.

With respect to Directive 1 (gg), Manitoba Hydro noted that Order 164/16 did not contain any timelines and it proposes to assess the allocation of common costs after the completion of the current GRA[143].

Treatment of Net Movement

Since the preparation of PCOSS14-Amended (based on IFF12), the adoption of IFRS has established a different standard when it come to the treatment of regulatory account deferrals and amortization for financial reporting purposes. This standard requires net income to be reported both before and after the impacts of rate-regulation. As a result, additions to regulatory deferral balances are initially expensed in their respective financial statement line items. These additions are then deferred and amortization is recognized in the net movement in regulatory balances[144].

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139 Order 164/16 defines Common costs as
140 COALITION/MH I-225 b)-e)
141 COALITION/MH I-223 b)
142 COALITION/MH I-243
143 PUB/MH I-150
144 Tab 6, page 40

This requires that the COSS deal not only with the amortization amounts (as was the case in PCOSS14-Amended) but also deal with the initial expense (prior to deferral) as well as the additions to the regulatory accounts. The treatment of the various accounting entries for each regulatory account is summarized in Schedule 21.

In principle the COSS treatment of both the additions to regulatory accounts and treatment of the subsequent amortization should reflect the nature of the costs being deferred and conform with the COSS treatment of the original IFRS expense. This is fairly easy to do for items such as the Power Smart Programs and the Regulatory costs which can be readily identified. In other cases, such as the ELG/ASL Differences, Manitoba Hydro's financial reporting system provides sufficient details for the both the deferral and the amortization to be functionalized. The only areas where some form of allocation is required are with respect to: i) Ineligible Overheads, ii) Site Restoration (non-Diesel) and iii) Regulatory Hearings (Acquisition).

In the case of Ineligible Overheads, the SAP Labour Allocator is used to determine the allocation of the initial expense and deferred amounts by function, while the COSS Labour Allocator is used to functionalize the annual amortization. Manitoba Hydro acknowledges that the $20 M of overhead previously capitalized would have been capitalized in proportion to direct labour charged to a capital project under construction, whereas these overhead costs are now allocated based on operating-related labour costs. The approach adopted by Manitoba Hydro is reasonable and allowance for the more simplified approach adopted can be made when interpreting the COSS results and considering the appropriate zone of reasonableness.

In the other two cases, the initial IFRS expense and the addition to regulatory accounts net out and the annual amortization is functionalized using the COSS Labour Allocator. All three amortizations are included with Building and Equipment depreciation (which is functionalized in a similar matter) for purposes of the COSS model[145].

[145] COALTION/MH II-29 b)

5.2.3 Direct Assignment

PCOSS18 directly assigns the following costs to customer classes[146]:

- Street Lighting assets and operating costs continue to be directly assigned to the Area & Roadway Lighting class.
- Diesel Generation and Distribution assets and operating costs continue to be directly assigned to the Diesel class.
- The SEP customer classes continue to be assigned costs equal to their revenues[147].
- Radial Taps serving GSL>100 customers are now directly assigned to that class.

These direct assignments reflect the conclusions and directives from Order 164/16 wherein:

- DSM costs are no longer directly assigned to customer classes per Directive 1 (f) (vi).
- The cost of radial taps are directly assigned to the GSL>100 customer class per Directive 1 (m).

It is also noted that consistent with Directive1 (e) that export revenue not be allocated to the Diesel class the diesel asset values used in PCOSS18 are net of capital contributions[148]. Also consistent with the Board Directive 1 (aa), Manitoba Hydro has maintained a single Area and Roadway Lighting class.

5.2.4 Treatment of Export Revenues

In regards to Export Revenues, Order 164/16 made the following directives:

1 (a) An Export class shall not be used in the COSS;

1 (b) Export revenue shall be credited to the domestic classes based only on each class's share of total Generation and Transmission costs;

1 (c) The following costs shall be deducted from gross export revenues:

(i) Energy costs for water rentals associated with exports

[146] Tab 8, page 14 and Appendix 8.1, Schedule 4
[147] COALITION/MH I-240
[148] PUB/MH I-159 b)

(ii) Variable hydraulic operating and maintenance costs associated with exports

(iii) The costs of the Affordable Energy Fund

1 (d) The costs of the Uniform Rate Adjustment shall not be deducted from export revenue;

1 (e) Export revenues shall not be credited to the Diesel class;

In preparing PCOSS18 Manitoba Hydro has complied with all of these directives. In its comments regarding the PCOSS14-Amended compliance filing, the Coalition noted that no information had been provided as to how the water rentals and variable hydraulic operating and maintenance costs associated with exports were determined. In its pre-filed evidence[149] Manitoba Hydro has provided an explanation of how these amounts were established for PCOSS18 and also provided further explanation in response to interrogatories[150].

In establishing the principles to be used in determining the COSS methodology the Board found the principle of cost causation is paramount[151]. This finding is reflected in Directive 1 (b) and the Board's observation that "the revenue from export sales is linked to the assets that give rise to export sales revenues, which are Generation and Transmission assets only, not Distribution assets"[152]. With this understanding as to the basis for the Board's directive regarding export revenue allocation there are two issues that arise.

First, as Manitoba Hydro has acknowledged[153], radial transmission lines are technically not integrated with the networked transmission system and therefore do not facilitate exports. As a result, since these assets do not give rise to (i.e., are not used for) exports, application of the Board's principles and rationale would suggest they should be excluded from the allocation of export revenues. The Board should refine its directive regarding the allocation of Export Revenue to exclude the roughly $7 M in costs associated with these assets.

[149] Tab 8, page 18
[150] GSS-GSM/MH I-8 and GAC/MH I-62
[151] Order 164/16, page 27
[152] Order 164/16, page 38
[153] COALITION/MH I-226 a)

The second issue is related to the fact that a small portion of exports are, indeed, made utilizing Manitoba Hydro's distribution system[154]. However, the associated revenues are only a small portion of total export revenues and attempting to recognize them in the allocation would introduce additional complexity without having any real effect on the results.

5.2.5 Generation

Order 164/16 made substantive changes in both the costs to be functionalized to Generation as well as how the costs were to be classified and allocated to customer classes.

Functionalization

Order 164/16 included the following Directive with respect to the facilities/activities and associated costs to be included in the Generation function:

> 1 (f) Costs that shall be functionalized as Generation are as follows:
>
> > (i) Manitoba Hydro's hydraulic and thermal generating stations, including operations and maintenance, fuel, and water rental costs;
> >
> > (ii) The costs related to wind energy purchases and import purchases;
> >
> > (iii) The following generation outlet transmission facilities: the Northern Collector System, the northern converter stations Henday, Radisson, and Keewatinohk, Wuskwatim generating station to Wuskwatim switchyard 230kV lines, St. Leon wind farm 230kV lines, St. Joseph wind farm 230kV lines, Pointe du Bois-Rover 66kV lines, Slave Falls-Pointe du Bois 115kV lines, and Pointe du Bois switching station;
> >
> > (iv) Bipoles I, II, and III;
> >
> > (v) The HVDC portions of the Dorsey and Riel converter stations; and
> >
> > (vi) DSM costs.

[154] COALITION/MH I-231

Also, while not explicitly referenced in the Directive, in its findings the Board determined[155] that the Midcontinent Independent System Operator ("MISO") fees, transmission fees, National Energy Board fees, and Manitoba Hydro's trading desk are to be functionalized as Generation.

With respect to the MISO fees, Manitoba Hydro notes[156] that it determines separately those that are transmission-related versus those that are generation-related as part of its integrated financial forecast. The transmission-related fees are associated with administering Manitoba Hydro's Open Access Transmission Tariff (OATT) requirements and makeup $5 M of the $6 M in total fees. Manitoba Hydro also points out that functionalizing these costs as Transmission is important for purposes of determining the OATT. The remaining $1 M is related to Manitoba Hydro's activities in the MISO markets and is functionalized as Generation[157]. However, the Transmission-related portion is subsequently sub-functionalized as US Interconnection. The result is that the $5 M is classified and allocated to customer classes in the same manner as Generations costs and, thus, the overall results are consistent with the Board's findings[158].

According to the Board's Order[159], specific generation outlet transmission facilities are to be functionalized as Generation "because this transmission is necessary to connect generating stations to the networked transmission system and power flows in only one direction on these lines. If the generating station is not in service, no power would flow on these lines and they provide no benefit to the networked transmission system".

The actual facilities included are based on recommendations[160] made by GAC and its consultant during the recent COSS Review. What is not clear and has not been confirmed is whether or not there are other generation outlet transmission facilities that meet the Board's criteria and should be functionalized as generation. The Board should direct Manitoba Hydro to review the connection facilities associated with it generating

[155] Page 45
[156] Tab 8, page 5
[157] Tab 8, page 5
[158] COALITION/MH I-241 a) & b)
[159] Page 45
[160] Order 164/16, pages 44-45

facilities to confirm whether or not there are any other such connection facilities that would meet the “generation outlet transmission” criterion.

In all other respects, PCOSS18 fully complies with the findings and directives as set out in Order 164/16[161].

Classification and Allocation

In Order 164/16 the Board made the following directives with respect to the classification and allocation of Generation costs:

> 1 (g) Wind purchases, water rentals and variable hydraulic operation and maintenance costs shall be classified as 100% Energy. All other Generation costs shall be classified as both Energy and Demand, with the proportions determined by the system load factor method. The system load factor shall be based on multi-year historical domestic load data and updated for each PCOSS;
>
> 1 (h) Generation costs classified as Energy shall be allocated on the basis of unweighted energy; and
>
> 1 (i) Generation costs classified as Demand shall be allocated by the top 50 Winter Coincident Peak hours of the domestic customer classes.

In PCOSS18, Manitoba Hydro has complied with these directives. In terms of Directive 1 (g) it is proposing that the system load factor be calculated using an eight-year average of historic domestic load factors[162]. Use of eight years is consistent with the approach used in the COSS for determining class demands. The use of an eight year average is reasonable.

In its Application, Manitoba Hydro notes that wind does provide both winter and summer peak capacity capability[163]. However, it notes that the capacity involved is of limited value such that recognizing it would have minimal effect on the COSS results.

[161] Tab 8, page 4
[162] Tab 8, page 9
[163] Tab 8, page 10

5.2.6 Transmission

Order 164/16 contained the following directives with respect to the functionalization, classification and allocation of Transmission:

> 1 (j) The domestic AC transmission system operating at voltages greater than 100kV, interprovincial interconnections, and U.S. interconnections shall be functionalized as Transmission;
>
> 1 (k) The domestic AC transmission system operating at voltages greater than 100kV and interprovincial interconnections shall be classified as 100% Demand and allocated on the basis of Winter Coincident Peak; and
>
> 1 (l) The U.S. interconnections shall be classified on the basis of system load factor, with the Demand portion allocated on the basis of Winter Coincident Peak and the Energy portion on the basis of unweighted energy.

Functionalization

Manitoba Hydro has functionalized transmission assets as directed in Order 164/16[164]. In response to information requests[165], Manitoba Hydro has provided details regarding the lines considered to be US Interconnections and their associated costs.

In its review of the February 2017 compliance filing, the Coalition questioned the change in costs assigned to transmission versus generation as a result of the direction regarding generation outlet transmission (more specifically the costs associated with the Pointe du Bois substation). In response to information requests posed in this proceeding[166], Manitoba Hydro has satisfactorily explained the change and confirmed that in both compliance filing the PCOSS18 the Pointe du Bois substation is functionalized 100% as Generation as directed by the Board.

The only other issue with respect to the functionalization of Transmission costs is with respect to the common settlement cost centres that have been ascribed to the Transmission function. Transmission-Common costs are associated with transmission

[164] Tab 8, page 6 and PUB/MH I-142
[165] GAC/MH I-63
[166] COALITION/MH I-218

R&D, external marketing, transmission planning, system operating and system protection, activities that cannot be directly attributed to a specific transmission asset[167]. Rather, these activities are related to all transmission assets that fall under the purview of Manitoba Hydro's Transmission business unit. This includes not only transmission assets that the Board has directed be assigned to the Transmission function but also those (e.g., HVDC and generation outlet transmission facilities) that are functionalized in the COSS as Generation. The "problem" is that the functionalization of these Transmission-Common costs was not adjusted in the current COSS to take into account the transmission facilities transferred to the Generation function.

In responding to this issue Manitoba Hydro notes that it is not clear what the appropriate cost adjustment would be and that, in any event, the impact on the COSS results would be small[168]. Given the other outstanding issues from the COSS Review that Manitoba Hydro, which includes a more generic study of the allocation of common costs (Directive 1 (gg)), it seems reasonable to park this issue for now. However, parties need to be mindful of such simplifications when establishing the appropriate zone of reasonableness and interpreting the results of the COSS.

Classification and Allocation

Manitoba Hydro has classified and allocated the Transmission function costs as directed in Order 164/16 and no issues were noted in either the compliance filing or PCOSS18 on these aspects of the COSS methodology.

5.2.7 Subtransmission

Order 164/16 included the following directives regarding the COSS treatment of Sub-Transmission:

> 1 (n) The Subtransmission function shall remain a separate function from Transmission, encompassing transmission assets less than 100kV but greater than or equal to 33kV; and

[167] COALITION/MH I-223
[168] COALITION/MH I-223

1 (o) Subtransmission shall be classified as 100% Demand and allocated by Winter Coincident Peak.

No issues have been noted in either the compliance filing or PCOSS18 regarding the COSS treatment of Subtransmission. Indeed, unlike the situation raised earlier with respect to Transmission-Common costs, it is noted that the operating costs identified as Common Subtransmission/Distribution Plant by the financial reporting system are subsequently split between the two functions[169]. The proportions approximate those in the COSS Labour Allocator. However, COSS transparency would be improved if the allocation of these costs, which is also done outside Manitoba Hydro's financial reporting system, was documented in the COSS model.

5.2.8 Distribution Plant

Order 164/16 included the following directives regarding the functionalization, classification and allocation of Distribution Plant costs:

1 (p) Assets that operate below a voltage of 33kV, including poles, wires, the low voltage side of substations, meters, and distribution transformers shall be functionalized as Distribution;

1 (q) Distribution poles and wires shall be classified as 100% Demand;

1 (r) The costs of distribution substations and distribution transformers shall be classified as 100% Demand;

1 (s) Service drops, meter investment, and meter maintenance shall be classified as 100% Customer;

1 (t) The Demand component of Distribution costs shall be allocated based on each class's Non-Coincident Peak;

1 (u) The Demand factor for the GSL 0-30kV class for distribution poles and wires shall be reduced by 30%;

1 (v) Manitoba Hydro shall update its Service Drops cost allocator including revisiting the weightings for GSS, GSM, and GSL 0-30kV 3-phase services. In

[169] Appendix 8.1, Schedule 3.1

the interim, the allocation methodology shall prorate the 103,000 Residential customers over the three classes based on the number of customers in each class; and

1 (w) Manitoba Hydro shall update its Customer-related allocators and weighting factors for its Distribution costs that are Customer classified, including the weightings for meter investment and meter maintenance.

Functionalization

Order 164/16 did not change the definition of Distribution Plant or the types of assets/activities that are to be assigned to it. Discrepancies noted in the Coalition's comments regarding the February compliance filing have been acknowledged[170] to be the result of formula errors that have subsequently been corrected. There are no issues with the functionalization of Distribution Plant in PCOSS18.

The only point of note with respect to PCOSS18's sub-functionalization of Distribution Plant costs is that the methodology now no longer includes a sub-function for Meter Maintenance whereas in PCOSS14-Amended (and the compliance filing) it did. Instead these costs appear to have been included with the Meter sub-function costs[171]. While both sub-functions were classified as customer-related, the customer weights applied in PCOSS14-Amended were different as between Meter Investment and Meter Maintenance. However, the operating costs associated with the PCOSS18 Meters sub-function are only a fraction of the total interest, depreciation and operating costs assigned. As result, this treatment is unlikely to have a noticeable effect on the COSS results.

Classification and Allocation

The only Directives in Order 164/16 that represented a change from Manitoba Hydro's proposed COSS methodology at the time of the COSS review were 1 (q) and 1 (v). In PCOSS18 Manitoba Hydro has changed[172] the classification of the Poles & Wires sub-

[170] COALITION/MH I-220
[171] This observation is based on the fact that the Meters sub-function now includes Operating expenses whereas in PCOSS14-Amended the Meters Investment sub-function did not.
[172] Specifically with respect to Poles & Wires;

function to 100% Demand which, in turn, impacts the allocation to customer classes[173]. Manitoba Hydro has also adjusted the customer count used in the allocation of services in accordance with Directive 1 (v)[174].

With respect to Directive 1 (w), Manitoba Hydro has updated the customer weightings for Meters[175] but has not done so for Services[176]. Similarly, Manitoba Hydro has not done any work[177] to revise the COSS methodology so as to better recognize that some customers make use of Manitoba Hydro's primary voltage system but not its secondary voltage facilities as suggested by the Board[178]. Furthermore, Manitoba Hydro has not provided any indication as when these issues or the other matters still outstanding with respect to Order 164/16 will be addressed[179]. The Board should provide clear timelines and it is suggested that completion for filing with the next GRA would be appropriate.

5.2.9 Distribution Services (Customer Services)

Order 164/16 included the following Directives with respect to the COSS treatment of Customer Services:

> 1 (x) Costs related to serving and communicating with customers after delivery of energy, including meter reading, billing, collections, information and customer assistance, advertising, sales, sections, research and development, rates and cost of service, load research, and other departmental costs such as Power Smart Energy Services, shall be functionalized and classified as Customer Services;
>
> 1 (y) The costs in the Customer Service sub-category within the Customer Consultation and Information category shall not be allocated to GSL 30-100kV or GSL >100kV customers, unless and until Manitoba Hydro can provide a fulsome description of these costs. With the exception of the costs in this sub-category, Manitoba Hydro's Customer Services allocators are appropriate; and

[173] Tab 8, page 11
[174] GAC/MH I-69
[175] PUB/MH I-146 a) & b)
[176] PUB/MH I-147 a)
[177] COALITION/MH I-249
[178] Order 164/16, pages 74-75
[179] PUB/MH I-150

1 (z) The weightings used to allocate the Customer Services costs shall be updated.

Functionalization

Underpinning Directive 1 (y) was a concern that while the Customer Service sub-function used in PCOSS14-Amended was allocated to all customer classes there was some question as to whether all of the activities in the sub-function were applicable to the GSL customers.

To address this concern Manitoba Hydro has effectively broken the sub-function down and created three sub-functions[180]:

- A General Customer Service[181] sub-function which consists of activities applicable to all customer classes,
- An Industrial and Commercial Solutions sub-function which consist of the activities of departments focused on GSL customers, and
- A Customer Service-Small Customers sub-function which represents services provided to smaller customers similar to what are provided to the GSL customers via Industrial and Commercial Solutions.

The nature of the activities captured under the new General Customer Service sub-function is set out below[182]:

- Education & Safety – Programs aimed at education and public safety around dams, waterways, substations, and overhead powerlines.
- Contact Centre – Outages – The initial point of contact for all customers regarding outages.
- Rates & Regulatory – Costs associated with regulatory processes related to rates and other matters.
- Marketing R&D - Activities include creating marketing plans, customer surveys, maintaining customer coding databases, and enhancing business development in the province.

[180] Appendix 8.1, Schedule 4.3
[181] Also included in this sub-function are Marketing R&D activities which in PCOSS14-Amended were a separate sub-function.
[182] MIPUG/MH I-11 b)

- Line Locates – Line locates involve activities related to both transmission and distribution facilities and are performed both to protect Manitoba Hydro's investments and for public safety[183].
- Building Moves and Safety Watches – Manitoba Hydro incurs costs related to facilitating building moves in order to inspect the route, as specified by the mover prior to the move, which are only partially recovered from the parties concerned. In addition, to ensure the safety of customers and their contractors when working in close proximity to Manitoba Hydro's facilities, the company provides a safety watch service for which costs are only partially recovered. Manitoba Hydro has confirmed that such services are provided to large as well as small customers and can involve transmission as well as distribution facilities[184].

Given the nature of the services included in General Customer Service it is reasonable that they be allocated to all customer classes.

Classification and Allocation

Consistent with the Board's Order, Manitoba Hydro classifies all of its Customer Services sub-functions as being customer-related. However, different weighting factors are used to establish weighted customer counts for purposes of allocating the costs in each sub-function.

Per Directive 1 (z), Manitoba Hydro has updated the customer weighting factors used for the following Customer Services sub-functions: Billing, Collections, Meter Reading, and Inspections[185]. For the three new Customer Services sub-functions the allocation is based on customer revenues for the applicable customer classes.

5.2.10 Conclusions

Manitoba Hydro has generally followed the Board's Order 164/16 principles and directives in its preparation of PCOSS18. Areas of departure are based on either a lack of data[186] or simplifying assumptions[187]. The lack of data regarding late payment

[183] MIPUG/MH I-11 c)
[184] COALITION/MH II-40 and MIPUG/MH I-11 e)
[185] Tab 8, page 12 and Appendix 8.1, Schedules 4.3 to 4.6.
[186] Example – Directive 1 (bb) regarding the allocation of Late Payment revenue

revenues by customer class and the subsequent use of revenue by class to allocate late payment revenues to non-Residential classes falls into the first category. Examples of the second would include: i) the allocation of Ineligible Overhead amortization to functions using the COS Labour Allocator, ii) the assignment of all Transmission-Common costs to the Transmission Function and iii) the elimination of the Meter Maintenance sub-function.

Also, the preceding discussion has noted a few instances where there is a mismatch between the Board's principle that "cost causation" should be the primary consideration determining the COSS methodology and a strict interpretation of the Board's directives. For some of these, such as the classification of wind energy and the allocation of export revenues based strictly on generation and transmission, refinement of the COSS treatment would have minimal effect on the results and introduce additional complexities. However in a couple of cases, specifically the functionalization of generation outlet transmission and the inclusion of radial lines in the allocation of export revenues, further consideration/review is warranted.

Finally, there are a number of areas where the Board determined further study/updating are required and Manitoba Hydro has yet to address. These include:

- Directive 1 (gg) regarding the allocation of common costs and the development of allocators that are more directly related to the causes of the common costs,
- Directive 1 (v) regarding adopted the allocator for Services, and
- Additional study/data regarding the appropriate treatment of primary and secondary distribution lines[188].

Clear timelines should be established for the completion of this work and it is suggested that completion for filing with the next GRA would be appropriate.

[188] Order 164/16, page76

5.3 Manitoba Hydro’s Revenue to Cost Ratios

5.3.1 Revenue to Cost Ratio Calculation

Revenue to cost ratios are determined for each customer class by dividing its total revenue by its total allocated costs (from the cost of service study). While it sounds straight forward, questions as to what is included in “revenues” and what is included in “costs” can lead to different formulations and different results. In the context of Manitoba Hydro’s cost of service study these questions relate to:

i. Whether the revenues used should include the additional revenues for each class that would arise from an across the board application of the rate increase assumed in the financial forecast. In Manitoba Hydro’s cost of service study and subsequent revenue to cost ratio calculations the additional revenue has been excluded[189].

ii. Whether export revenues (net of the costs assigned to them) should be assigned to each customer class as additional revenue or as a cost offset. In Manitoba Hydro’s cost of service study export revenues are treated as additional revenue and included in the numerator of the revenue to cost ratio calculation[190].

iii. Whether Other Revenues are assigned to each customer class as additional revenue or treated as a cost offset. In Manitoba Hydro’s case, the treatment of Other Revenues is mixed. Some, such as Late Payment Revenue, are allocated to customer classes and treated as additional revenue. In other instances, such as Inspection Fees and Joint Use charges, the revenues are treated as a cost offset.

iv. Whether the calculation should even include (net) export revenues. Manitoba Hydro’s cost of service analysis calculates the ratios both with and without export revenues. However, in subsequent discussion of the results[191], Manitoba Hydro focuses on the revenue to cost ratios that include export revenues in the calculation.

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[189] Tab 8, page 17
[190] Appendix 8.1, page 2
[191] Tab 8, page 25

With respect to the first issue, the more common practice when using a forecast test year is to include the additional revenues from the requested/approved[192] rate increase. This approach allows the regulator and interested parties to see what the ratios would be if the utility applied the rate increase equally across customer classes. The ratios calculated based on the two approaches for a particular customer class will differ based on the degree to which the additional revenue from the rate increase differs from the additional costs (in the form of net income) that will be allocated to the class. Since net income is allocated using rate base the results of two approaches may not be all that different, provided the revenue to cost ratio are fairly close to 100%. The reason for this is that rate base directly determines the allocation of both finance expense and interest costs and will bear a strong relationship with the allocation of depreciation and, to a lesser extent, operating costs. Manitoba Hydro has provided the results[193] of its COSS if the 7.9% rate increase was included and the resulting revenue to cost ratios for the various customer classes vary by less than 1%.

The exclusion of export revenue from the revenue to cost ratio calculation results in an overall system ratio that is less than 100%. In order to interpret and apply the results for rate-setting purposes it would be necessary to re-base the results. However, this approach to the calculation ignores the fact that exports and export revenues are not incidental to Manitoba Hydro's operations but rather a key and significant factor.

Overall, the approach taken in addressing each of the first three issues is a matter of judgement and what's important is that a consistent approach is used over time and that the fact such judgements are involved is recognized when interpreting and applying the COSS results. However, with respect to the fourth issue export revenues should be included in the calculation given that exports are an integral and significant part of Manitoba Hydro's operations and planning. Based on this assessment, Manitoba Hydro's approach to calculating the revenue to cost ratios is reasonable.

PCOSS18 results in the following revenue to costs (or RCC) ratios.

[192] The "approved" rate increase would be used in compliance filings after the regulator has issued its Decision regarding the requested rate increase and but before the actual rate schedules have been approved.
[193] PUB/MH I-132

Schedule 22

PCOSS18 - Revenue to Cost Ratio Results

Cusomer Class	Revenue to Cost Ratio
Residential	94.80%
General Service - Small ND	112.50%
General Service - Small D	101.10%
General Service - Medium	98.30%
GSL 0-30 kV	99.10%
GSL 30-100 kV	109.30%
GSL > 100 kV	108.60%
Area & Roadway Lighting	100.30%
Source: Tab 8, page 27	

5.3.2 Revenue to Cost Ratio Interpretation (Zone of Reasonableness)

As the Board noted in Order 164/16[194], cost of service studies may appear to arithmetically exact but in fact they are not. There are a number of reasons for this:

- As the Board also noted there is no single industry standard when it comes to cost of service methodology. Utilities and regulators make judgements and often choose from a range of industry practices with respect to methodology as well as the appropriate cost drivers. An example of this is the Board's decision[195] to adopt the System Load Factor method for purposes of classifying generation costs where the choice involved considerations not only of cost causality but also considerations related to understandability and practicality of implementation.
- Judgements and simplifications are often required in applying a particular methodology due to data limitations or the complexity that would be involved in achieving greater precision.

[194] Page 5
[195] Order 164/16, Page 48

- The data used in cost of service studies is often imprecise, being based on estimates from particular point in time or sample data. Examples of this would be the estimates used for the coincident peak (CP) and non-coincident peak (NCP) allocators (which are derived from load research data) and the weightings applied to the customer counts for purposes of allocating various Customer Services sub-functions (which are usually based on snap shop in time).

The fact that cost of service studies are not viewed as precise analysis has led to the practice of establishing revenue to cost ratio ranges within which it is considered that a customer class is paying its fair share of costs. These ranges are referred to as zones of reasonableness (“ZOR”). While the ranges used vary by regulatory jurisdiction, the ranges most typically used are 95% to 105% and 90% to 110%. Choice of the range is a matter of judgement but often involves considerations such as maturity of the utility’s COSS and the quality of the data used. At this point, the choice of an appropriate ZOR should also recognize that the COSS methodology is still evolving as further work on Manitoba Hydro’s part is required. This would suggest that a broader range, at least in the interim, is more appropriate.

As Manitoba Hydro points out[196] in establishing a ZOR it is also important to consider the purpose for which it is being used. In Order 164/16 the Board noted[197] that the results of the cost of service study (i.e., the revenue to cost ratios) are but one input into the ultimate decision as to the rates that will be charged to a customer class and the revenues that will result. In this context, a range can be established based on judgement as to the precision (and lack thereof) of the cost of service methodology taking into account the various issues noted above.

However, it is a totally different matter if the ZOR is meant to define the range in which the revenue from each customer class must fall based on the rates approved by the regulator. Indeed, such a use of the ZOR (even if set using a wider range) would be inappropriate as it cannot possibly account for all of the factors the regulator may need to take into account in determining what are just and reasonable rates and, thereby,

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[196] PUB/NG I-137

[197] Pages 6 and 16

unduly fetter the regulator's authority. As the Board noted in Order 164/16 "in setting domestic electricity rates, the Board has discretion as to what, if any, use is made of the COSS"[198].

5.3.3 Other Factors to Consider in Rate Making

In Tab 9[199] of the Application Manitoba Hydro sets out its general rate making objectives which are summarized below:

i. Recovery of the Revenue Requirement
ii. Fairness and Equity
iii. Rate Stability and Gradualism
iv. Efficiency
v. Competitiveness in Rates
vi. Simplicity and Understandability

Fairness and equity involves consideration as to whether individual customers and customer classes are paying their "fair" share of the overall revenue requirement. One common measure or standard of "fairness" in this regard is whether customers are paying what it cost to serve them and, from an equity perspective, are customers who use similar services and have similar consumption characteristics and supply arrangements paying similar costs. Cost of service studies provide such a measure and, hence, their use as an input into the rate setting.

Rate stability and gradualism includes considerations such as customer bill impacts and avoiding capricious changes in rates.

Efficiency is concerned with the degree to which rates encourage efficient use of electricity. This does not necessarily mean encouraging customers to use less but rather encouraging customers not to be wasteful while at the same promoting usage where appropriate. This is often referred to as sending the right "price signal" and linked to concepts of economic efficiency and marginal cost considerations.

[198] Page 16
[199] Page 2

Simplicity and understandability refer to the ability of customers to understand their rates and how their usage will affect their bills.

Manitoba Hydro's rate objectives are generally consistent with those used by other utilities and accepted by the industry overall. This can be seen by comparing them with the criteria for a desirable rate structure established by Bonbright in 1961[200] and still widely referred to today:

i. The related, "practical" attributes of simplicity, understanding, public acceptability, and feasibility of application.
ii. Freedom from controversies as to proper interpretation.
iii. Effectiveness in yielding total revenue requirements under the fair-return standard.
iv. Revenue stability from year to year.
v. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
vi. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
vii. Avoidance of "undue discrimination" in rate relationships.
viii. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

    a. In the control of the total amounts of service supplied by the company;

    b. In the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, etc.)

However, there are two key differences:

1. The Bonbright criteria include consideration of "public acceptability". This would go beyond simple understandability and also include issues of broader public acceptability and public policy considerations.
2. The Bonbright criteria do not include a specific reference to competitive rates, only to rates that are efficient and encourage the economic use. However, maintaining

[200] J.C. Bonbright, *Principles of Public Utility Rates*, page 291.

competitive rates could be viewed as a public acceptability/public policy consideration.

Applicability to Manitoba Hydro's Current Circumstances

Manitoba Hydro's Application requested rate increases of 7.9% for each of the two years the current GRA is addressing[201]. This is already four times the rate of inflation and challenging from a public acceptability perspective. Higher customer class rate increases due to inter-class revenue adjustments would be even more problematic.

In the current Application Manitoba Hydro has included as its metric for ensuring rate stability and gradualism a requirement that the annual adjustments to revenues by customer class should be less than two percentage points greater than the overall proposed increase[202]. However, it is important to recall that this metric was established a number of years ago when proposed overall rate increases were much lower than those currently before the Board[203]. Circumstances have changed materially and it is questionable whether the same metrics are appropriate today.

With respect to efficiency, as part of its Application, Manitoba Hydro filed information comparing the marginal costs[204] to serve each customer class with the class' average revenue[205]. However, during the interrogatory process parties identified a number of issues with marginal costs values used including: i) the way losses were incorporated and ii) the assumption of a 100% load factor for each class which ignores the differences in annual load profiles across customer classes (e.g. peak vs. off-peak, seasonality and load factor). Manitoba Hydro has been unwilling/unable to break its marginal costs down by time of use period[206]. The following schedule attempts to address some of these issues by varying the loss factor applied to each customer class

[201] Tab 1, page 1
[202] Tab 9, page 2
[203] For example the same criteria was included in the General Rate Application for 2004/05 and 2005/06 rates when the requested increases were 3% and 2.5% respectively (Tab 9, page 3)
[204] Marginal costs are forward looking and based on the cost of serving an additional increment of load in terms of the incremental facility costs and expenses that would be incurred. In economic theory, economic efficiency is achieved when all resources are priced at their marginal costs and consumers can respond accordingly.
[205] Tab 8, page 31
[206] See PUB/MH I-131 and COALITION/MH

and revising the marginal costs for transmission and distribution to reflect the variations in customer class load factors.

Schedule 23	MARGINAL COSTS VS. AVERAGE REVENUE COMPARISON										
	Marginal Cost (cents/kWh @ 100% Load Factor)				Class Load	Marginal Cost - Trans. & Distr @ Class Load Factor (cents/kWh)				Avg. Rev.	Revenue/ Marginal
	Gen.	Trans.	Distr.	Total	Factor	Gen.	Trans.	Distr.	Total	(cents/kWh)	Cost
Residential	6.34	0.56	0.87	7.77	51%	6.34	1.09	1.70	9.13	8	87.6%
General Service -SND	6.34	0.56	0.87	7.77	62%	6.34	0.90	1.39	8.63	8.6	99.6%
General Service-SD	6.34	0.56	0.87	7.77	67%	6.34	0.84	1.30	8.48	6.85	80.7%
General Service-M	6.34	0.56	0.87	7.77	73%	6.34	0.77	1.19	8.30	5.98	72.1%
GSL 0-30	6.34	0.56	0.87	7.77	83%	6.34	0.68	1.05	8.07	5.14	63.7%
GSL 30-100	6.1	0.54	0	6.64	92%	6.1	0.58	0.00	6.68	4.43	66.3%
GSL>100	6.1	0.54	0	6.64	94%	6.1	0.57	0.00	6.67	4.01	60.1%

Sources: GAC/MH II-24 b) - for marginal costs with revised losses
Appendix 8.1, Schedule 5.3 - for usage data to calculated class load factors
Tab 8, page 31 - for Average Revenue values
Note: Revised Marginal Trans. And Distr. Marginal based on class load factor calculated by dividing values based on 100% by the class load factor

The revised revenue to marginal cost ratios suggest that, from an efficiency perspective, the rates currently being paid by the GSL customers are more out of line (i.e. below) with marginal costs than the rates currently being paid by smaller volume customers. Consideration of these results would support a shift in revenues to the larger volume customer classes.

Broader public acceptability and public policy considerations that have been acknowledged as relevant by the Board in the past the Board include:

- The impact of rate increases on “captive” electricity customers which would include Residential electric space heating customers in non-gas areas[207],
- The impact of rate increases on low income customers[208], and
- The policy intent and impacts of legislated changes such as the current legislated requirement for uniform rates and the commitment at the time the policy was introduced that it would not impact on customers rates[209].

While the aforementioned list of public acceptability and public policy matters focuses primarily[210] on the Residential class, it is likely that additional considerations exist for other customer segments that would be relevant in the Board’s determinations.

[207] Order 5/12,page 220
[208] Order 73/15, page 22
[209] Order 164/16, page 39. See also the ECS Evidence from the COSS Review, pages 49-50

Overall, it is the Board's responsibility to determine the relevance of the various factors along with the cost of service study results and balance them in a manner that results in just and reasonable rates. However, a key consideration in these deliberations needs to be the magnitude of the overall average rate increase. It is suggested that several of the considerations noted would have to align or other accommodations also be made before even higher average rate increases for one or more of the customer classes could be considered.

6. RATE DESIGN FOR THE RESIDENTIAL CLASS

6.1 Background

Prior to the 2004 GRA Manitoba Hydro's Standard Residential rate structure consisted of a monthly basic charge and two energy charges, one for the first 175 kWh used each month and a lower energy charge for the balance of the kWhs used each month. As part of its 2004 GRA Manitoba Hydro proposed to recover all of the additional 2004 revenue requirement attributable to the residential class through an increase in the energy rate for the tail or second block. Furthermore, the Application called for the elimination of the first 175 kWh energy block and the establishment of a single energy block in the second year covered by the Application. In its decision, the PUB expressed the view that "MH's proposal regarding rate structure and the shift to increasing energy charges is reasonable, and promotes conservation" [211].

In the same decision, the PUB noted there was an outstanding directive for Manitoba Hydro to study the merits of implementing an inverted rate structure for all customer classes and expressed the hope that "inverted rate structures can be further employed to encourage conservation as well as address market signals for some customer classes"[212]. Subsequently, in Order 117/06 dealing with Manitoba Hydro's Cost of Service methodology, the PUB directed[213] the Company to bring forward proposals to eliminate declining block rate schedules.

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[210] Uniform rates also impacted the GS-Small, GS-Medium and A&RL classes
[211] Order 143/04, page 98.
[212] Page 99
[213] Page 77

As part of its Application for interim rates effective March 1, 2007, Manitoba Hydro proposed to eliminate the first energy block and move to a single energy charge. However, the PUB concluded that such a change should come out of a GRA hearing where interested parties could discuss the change within a broader context[214]. In the same Order, the PUB went on to add that “the elimination of declining rate blocks would best be part of a program towards enhanced energy efficiency and conservation”.

In its Application for rates effective April 1, 2008, Manitoba Hydro’s proposed[215] to maintain the monthly Basic Charge at its current level and to recover the increased revenue required solely from the Energy Charge. Furthermore, Manitoba Hydro proposed to eliminate the declining block structure and replace it with an inverted rate with the first 900 kWh per month priced a lower rate. Finally, Manitoba Hydro signalled its intention to focus future rate increases more on the energy portion of the rate structure and, in particular, on the second block rate with a view to moving it towards marginal cost[216].

In Order 90/08 the Board approved[217] what it termed “the modest introduction of inverted rates for the residential class” and subsequently approved of an inverted rate structure effective July 1, 2008[218]. In the summary outlining its decision the Board noted[219]:

i. The disconnect between current electricity prices set based on the cost of facilities acquired decades ago and the higher cost of new generation and transmission facilities.
ii. The recent escalation in natural gas prices such that space heating by electricity was cheaper than by natural gas for all residences other than those that heat by way of a high-efficiency gas furnace.
iii. A concern that, if the trend continues and the disconnect between electricity and natural gas grows, more and more new and existing residences may select or

[214] Order 20/07, page 4
[215] Application Tab 10, page 4
[216] COALITION.MH U-47 f) and PUB/MH I-12 a)
[217] Page 25
[218] Order 91/08
[219] Order 90/08,page 8

convert to electric heating, driving up domestic electricity load and limiting export sales and profits.

At the same time the Board noted[220] the concern expressed by some parties regarding the effect that would be experienced by low-income customers as well as residential customers and businesses that use electricity for space heating and may not have natural gas as an optional heating source.

However, in its decision regarding Manitoba Hydro's Application for interim rates effective April 1, 2011, the Board noted[221] that circumstances regarding natural prices had changed and that Manitoba Hydro had yet to reflect consideration of home heating loads in its rate design. With this change the Board directed that Manitoba Hydro apply the Residential rate increase to the first energy block rate so as to eliminate the inverted rate and then to keep the two energy block rates equal, effective April 1, 2011.

Residential rate design continued to be a matter of interest to parties during the 2011/12 & 2012/13 GRA and in Order 5/12 the Board directed that Manitoba Hydro file a report/status update on "Inverted Rates, with a view to creating a significantly higher-priced second energy block, but providing an accommodation to electric heat customers, some of which do not have access to natural gas for heating"[222].

More recently, in its final Order[223] regarding Manitoba Hydro's 2014/15 & 2015/16 Rate Application, the Board recognized that higher electricity prices will have an impact on lower income ratepayers and this was a particular concern with respect to all-electric customers, many of whom live in areas in which natural gas is not available as an alternative heating source. In the same Order[224] the Board also noted its intention to evaluate any future proposals for bill assistance programs from a comprehensive policy perspective (rather than through the lens of jurisdictional constraints).

[220] Page 13
[221] Order 40/11, page 30
[222] Page 220
[223] Order 73/15, page 27
[224] Page 29

Finally, in establishing the issues to be dealt with as part of the recent COSS Review Manitoba Hydro requested that matters of rate design be deferred to the next GRA[225].

6.2 Current Proceeding and Manitoba Hydro's "Proposal"

6.2.1 Manitoba Hydro's Alternative Residential Rate Design

Manitoba Hydro's initial Application provided[226] a general discussion of rate design policy issues but did not contain any specific rate design proposals. Rather the requested 7.9% rates increases were applied across the board to all rate components. Subsequently the Board required Manitoba Hydro to include in its GRA filing the Company's proposals and supporting materials for the rate-related matters[227]. During the procedural conference[228] Manitoba Hydro proposed to hold workshop involving interested parties:

> "to come up with a workable alternative residential rate design that takes into consideration impacts on electric heat customers. In other words, it would be a rate design that would adopt some level of cross-subsidy within the residential class between electric heat and non-electric heat customers".

The workshop was held on July 13, 2017 and on September 14, 2017 Manitoba Hydro filed a Report on Residential Rate Design with the Board. While the report[229] included alternative Residential rate structures Manitoba Hydro has made it clear that the filing was for informational purposes only and that it was not amending its Application which calls for across the board increases to all rate components. In its response to information requests[230] Manitoba Hydro explained its expectations as to outcomes from proceeding regarding the report:

> "Manitoba Hydro notes that there are significant steps that are required to be taken prior to introducing a change to rate design. Issues such as the identification of impacts to affected customer groups, the planning and delivery of

[225] Order 26/16, page 7
[226] Tab 9 page 3
[227] Exhibit PUB-5
[228] Pre-Hearing Conference, June 12, 2017 Transcript, page 219
[229] September 14, 2017 letter to PUB and Appendix 9.14, page 12
[230] COALITION/MH II-77

> customer awareness and customer education information, the identification of required modifications to billing and customer information systems and the training of staff must be considered and addressed prior to implementing changes to rate structure.
>
> Therefore, Manitoba Hydro expects that in its Order from this GRA, the PUB may provide further direction on rate design matters, but will not direct the implementation of a change to residential rate structure for April 1, 2018 rates."

Manitoba Hydro's Alternative Rate Design would segregate Residential Electric Heat Billed customers from Residential Non Heat Billed customers and deliberately shift a portion of the proposed rate increase from the former on to the latter. The shift would be sufficient to increase the energy charge for Non Heat Billed customers by approximately 2% higher than the class proposed average of 7.9% which amounts to roughly $5.2 M[231].

Using these principles and the currently proposed April 1, 2018 Residential rates, Manitoba Hydro has designed illustrative rates for the two customer segments. The results are set out below:

Scheudule 24

Proposed April 1, 2018 Residential Rates (200 amps or less)

	Basic Charge	Energy Charge
Residential Basic	$8.72	$0.08843 / kWh

Alternative Residential Rate Design (200 amps or less)

	Basic Charge	Energy Charge
Residetial Basic Non-Heat	$8.72	$0.09007 / kWh
Residential Basic Heat	$8.72	$0.08728 / kWh

Sources: Appendix 9.14, page 13
Appendix 9.4 (Updated), page 2

[231] Appendix 9.14, pages 12-13

Manitoba Hydro's report also provided the monthly bill impacts associated with its alternative residential rate design which are copied below[232]:

Figure 9. Bill Impact Tables – Alternative Rate Scenario.

Residential Basic Standard (Illustrative Rates)

kWh	AUG 2017 $ / Month	APR 2018 $ / Month	Difference in $ / Month	Percent Change
250	$28.57	$31.24	$2.67	9.35%
750	$69.55	$76.27	$6.72	9.66%
1 000	$90.04	$98.79	$8.75	9.72%
2 000	$172.00	$188.86	$16.86	9.80%
5 000	$417.88	$459.07	$41.19	9.86%

Residential Basic All Electric (Illustrative Rates)

kWh	AUG 2017 $ / Month	APR 2018 $ / Month	Difference in $ / Month	Percent Change
250	$28.57	$30.54	$1.97	6.90%
750	$69.55	$74.18	$4.63	6.66%
1 000	$90.04	$96.00	$5.96	6.62%
2 000	$172.00	$183.28	$11.28	6.56%
5 000	$417.88	$445.12	$27.24	6.52%

6.2.2 Assessment of Manitoba Hydro's Alternative Residential Rate Design

As Manitoba Hydro has indicated, the selection of an appropriate rate design involves the consideration and weighting of a number of different rate setting objectives. The following table provides a high level of assessment of Manitoba Hydro's Alternative Residential Rate Design as compared to its current Residential Rate Design based on the more generally applied Bonbright criteria discussed in section 5.3.3. More detail discussion and explanation is provided following the schedule.

For purposes of the schedule "freedom from controversies as to proper interpretation" is assumed to be captured as part of the "understandability" considerations and "public acceptability" has been separated out as another consideration to be grouped with "public policy" considerations. Similarly, "avoidance of undue discrimination in rate relationship" is considered to be captured under "fairness and equity" and "revenue stability" is considered as an element of "revenue requirement recovery".

232 Appendix 9.14, page 15

Schedule 25: Assessment of Manitoba Hydro's Alternative Rate Design

Ratemaking Objective	Consideration	Merits of Alternative Rate Design (ARD)
Recovery of Revenue Requirement	Rates must provide Manitoba Hydro the opportunity to fully recover its allowed revenue requirement. Stability of revenue from year to year	To the extent the residential load forecast considers electricity vs. natural gas prices, the effects will be similar. Independently altering the rate design could lead to inconsistencies between rates and allowed revenue requirement.
Fairness and Equity	Rates should reflect cost to serve and treat equal customers equally (i.e., same "rates"). Usually judged using COSS principles.	ARD will result in lower "rates" for higher cost to serve customers and situations where similar customers are paying different rates.
Rate Stability	Stability of rate structures over time with gradual changes when required	ARD introduces slightly more variation in the rate increase for Residential customers.
Efficiency	Provide appropriate price signals regarding the value of energy so as to promote the efficient and economic use of electricity. Usually judged using marginal cost principles	The marginal cost to serve Electric Heat customers is likely higher than for Non Heat customers. The ARD will further distort the "price signal" to Non-Heat customers. The result for Heat customers is unclear.
Simplicity and Understandability	Customers should easily understand how changes in usage will affect their bills	Similar to existing rate structure. The billing system can currently distinguish heating customers.
Public Acceptance and Public Policy	Support public policy and reflect public consensus.	Addresses previous public interest issues raised by PUB but does so by capturing a broader population of customers/usage. Degree of "public acceptance" unknown.

Recovery of Revenue Requirement

Manitoba Hydro's residential load forecast currently incorporates considerations of electricity vs. natural gas prices in forecasting the load for new electric homes[233]. In this case, the implementation of the ARD would need to be reflected in the load forecast in order to avoid inconsistencies between the load forecast used to determine the revenue requirement and the rate structures being used to recover the revenue requirement. It is less clear the extent to which electricity vs. natural gas prices are considered in determining the future heating sources for existing dwellings and, therefore, whether a similar issue exists regarding this aspect of the load forecast as well.

Fairness and Equity

Using available load research data, Manitoba Hydro has performed a COSS which includes both Residential Heat and Residential Non-Heat customer classes[234]. The resulting revenue to cost ratios (where the revenues are based on the current rate structure) are: 103.68% for the Non-Heat class and 90.1% for the Heat class. This means that, from a COSS perspective, it costs more (i.e., $/kWh) to serve a Heat customer than a Non-Heat customer.

The results are not surprising as the load data for the two classes[235] indicates that the Residential Heat customer segment has a lower load factor than the Residential Non-Heat customer segment when measured on either a coincident peak (CP) or non-coincident peak basis. The means that any demand related costs allocated[236] to the Residential Heat customer class must be recovered over fewer kWhs. This is illustrated in the following schedule.

[233] PUB MFR 65, Attachment 1, pages 60-61 and COALITION II-10
[234] PUB/MH II-93
[235] PUB/MH II-93
[236] In the COSS demand costs are allocated using either a CP or NCP based allocator

Schedule 26 - Residential Heat vs. Non-Heat Load Factors

	Energy @ Gen. (GWh)	CP @ Gen. (MW)	NCP @ Gen. (MW)	CP Load Factor	NCP Load Factor
Residential Heat	5168.3	1328.5	1476.1	44%	40%
Residential Non-Heat	3569.6	635.3	781.5	64%	52%
Source: PUB/MH II-93					

The Alternative Rate Design, which would reduce the rates to the Electric Heat customers and raise rates for the Non-Heat customers, would further exacerbate the discrepancy between the revenue to cost ratios such that the rates for both segments would be less reflective of the cost to serve (measured based on COSS).

In terms of whether equal customers are being treated equally, all residential customers generally use the same types of facilities and have the same customer service support available to them. What distinguishes them from a system perspective and also from a customer perspective is that their level of electricity use varies. However, since only Electric Heat customers receive the lower rates this will result in residential customers who have the same electricity usage paying different bills.

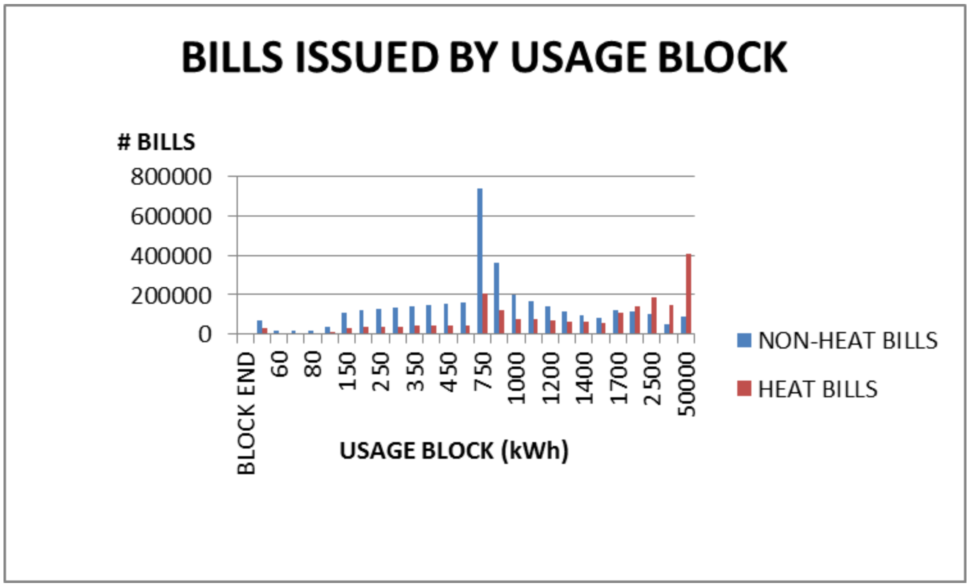
To appreciate the extent of the issue the following chart sets out the number of monthly bills issued to each of the two customer segments by kWh usage block in 2016/17. As the chart illustrates there is a fair degree of overlap[237]. Indeed, the average monthly usage for Heat customers was 1,901 kWh and more than 7% of the Non-Heat customers had bills with higher usage than this. On the other side, the average monthly usage for Non-Heat customers was 893 kWh and more than 27% of the bills issued to Heat customers were for usage less than 750 kWh[238].

Clearly there are equity issues associated with the Alternative Rate Design.

[237] The last usage block for Heat customers has a high number of bills as it represents all bills with usage over 3,000 kWh per month.

[238] The source of the data for both the chart and values quoted is COALITION/MH II-32

Schedule 27: Distribution of Heat vs. Non-Heat Bills



Efficiency

Insufficient information is available to determine the marginal cost of serving a Heat vs. a Non-Heat Residential customer. However, it is reasonable to conclude that the marginal cost of serving a Heat customer is higher based on the following:

- As discussed earlier the Heat customer has a lower load factor. As a result, the marginal transmission and distribution costs, which are calculated on a $/kW basis, must be spread over fewer kWh for each kW of load place on the system.
- The Heat customer will, by definition, have a higher concentration of usage in the winter season and in its October 6, 2017 letter[239] to the Board regarding the CSI motions Manitoba Hydro confirmed that winter marginal costs were higher than summer marginal costs.

Earlier analysis indicated that, after allowing for a Residential load factor of less than 100% (see Schedule 23), the marginal cost of serving Residential customers was likely in excess of 10 cents per kWh (in 2016$) which is higher than the current (August 1, 2017) energy rate of 8.84 cents/kWh. However, Manitoba Hydro has indicated that the marginal cost of generation used in calculating the marginal cost values provided in the

[239] Page 32

Application was based on the 2015 Export Price Forecast[240]. This export price forecast is higher than that used in IFF16 and even higher still than the 2017 Export Price Forecast used in the IFF16 Update[241]. Manitoba Hydro has also indicated[242] that it is in the process of updating its marginal cost estimates based on the 2017 Export Price Forecast. Based on the price differences discussed in the Supplement to Tab 3[243], it is reasonable to assume that the results will be such that the marginal cost to supply an average Residential customer will be equal to if not less than the current energy rate.

Overall, it appears that the Alternative Rate Design will further distort efficiency of the price signal for Non-Heat customers, as it increases the energy rate and their marginal cost is less than that for the Residential class overall. In the case of the Heat customers the results are not as clear. The Alternative Rate Design would reduce the energy rate but the marginal cost to supply this segment is higher than that for the Residential class overall. Whether the overall result is an energy rate for the Heat customers that is higher or lower (and by how much) than the updated marginal costs is uncertain.

One thing that is clear from the preceding discussion is that with Residential energy rates close to marginal costs there is little justification, from an economic efficiency perspective, for the re-introduction of inverted rates for the Residential class overall as any significant differential would distort the price signal to customers.

Simplicity and Understandability

The Alternative Rate Design uses the same rate form as the current Residential rates – just different values. Therefore, in terms of customers understanding the rate and how it impacts their electricity bill, there is no real difference between the two.

From an implementation perspective the Alternative Rate Design does not appear to present any issues for Manitoba Hydro. Manitoba Hydro's billing system current tags Residential customers as Heat or Non-Heat customers for tax purposes[244] based on the *Retail Sales Act*, C.C.S.M. c. R130, section 2(1.2). This section defines the criteria for

[240] PUB/MH I-131 a) – c)
[241] Supplement to Tab 3, pages 6-7
[242] COALITION/MH I-132 i)
[243] Pages 6-7
[244] COALITION/MH II-80 a)

being a Heat customer as heating a dwelling unit in which the purchaser resides, and at least 80% of which has the permanently installed capability of being fully heated by electricity.[245].

Public Acceptability and Public Policy

The Board has indicated in previous Orders that it considers the impact of electricity rates on space heating customers, particularly low income customers and those in areas where natural gas is not available to be a matter of concern and supported the development of initiatives to address bill affordability for low income customers. Manitoba Hydro's recent financial projections which include requested and future rate increases at twice the level previously sought can only serve to further strengthen these concerns.

Manitoba Hydro's Alternative Rate Design does help to address these concerns in that it lowers the bills for electric space heating customers. Also, by lowering the energy rate it provides greater "relief" to those customers who use more electricity for space heating and, as a consequence, will have higher bills.

However, there is a "cost" in terms of lost revenue that must be addressed and paid for. The past concerns expressed by the Board involved the impact of electricity rates on low income customers, with a particular concern for customers with electric space heating and, more specifically, customers with electric space heating in areas where natural gas is not available. In contrast, Manitoba Hydro's proposal is applicable to all electric heating customers in all months of the year. As a result, while it does not capture low income customers without electric heat, the proposal does go beyond the specific segments of most concern to the Board. By including a wider population of customers the "cost" for a given level of benefit increases. A more targeted approach would: i) lower the "cost" for a given level of benefit or ii) allow the benefit provided to be increased.

It is acknowledged that the legislative requirements for uniform rates[246] precludes classifying customers solely on the region of the province in which they are located and

[245] COALITION/MH II-80 b)

thereby having different rates for those areas where natural gas is available versus those were it is not. However, since the legislation makes specific reference to classifying "solely" on the basis of region of the province it begs the question as to whether customer classifications that combine geographic and other considerations (such as the use of electricity for space heating) would be permissible. This is question that may warrant investigation.

The second point is that the Alternative Rate Design provides a benefit in all months of the year. The following schedule sets out the seasonal distribution of energy use by Residential Heat customers and indicates that a significant portion of their usage is in the non-heating months. As explained in the interrogatory responses[247], Manitoba Hydro only reads meters bi-monthly and bills were assigned to seasons based on when the bill was issued. This is likely what accounts for the high percentage of annual use attributable to the Spring period (March to May) since for some bills will include usage that occurred in January and February.

Schedule 24

ELECTRIC HEAT CUSTOMER - USE BY SEASONS

	Energy Use (GWh)	%
Summer	524.7	13.3%
Fall	704.6	17.9%
Winter	1570.4	39.9%
Spring	1140.7	28.9%
Total	3940.4	

Source: COALITION/MH II-32 (based on 2016/17 billing data)
COALITION/MH I-88 (for seasonal definitions)

[246] The Manitoba Hydro Act, Section 39 (2.1) & (2.2). Section 2.2(b) specifically states that "customers shall not be classified based solely on the region of the province in which they are located or on the population density of the area in which they are located"
[247] COALITION/MH II-88

The fact Manitoba Hydro only reads customers meters bi-monthly and then issues bills on 20 different billing cycles each month[248] makes attempting to target the alternative rate design based on seasonal use difficult, since the same seasonal "definition" cannot be readily applied to all customers. Adopting a seasonal definition linked to when the electricity was used would require pro-rating the usage for any bill where the usage period overlapped two seasons. The other alternative would be to base the seasonal definition on when the bill was issued. However, this would lead to different customers seeing different rates for usage on the same day[249]. Either of these two approaches is likely to make the bills more difficult to understand[250] and more challenging from a public acceptability perspective. However, it would be useful for Manitoba Hydro to undertake some consumer research on this issue in conjunction with the acceptability of providing relief to electric heat customers in all months of the year versus just the "heating" months and the willingness of its customer base to support (i.e. pay for) such initiatives.

As already noted, Manitoba Hydro's proposal does not specifically address the matter of low income customers, except that in being applicable to all residential electric heating customers it is also applicable to low income customers with electric heat. A more targeted low income customer focused rate would cost less (in terms of reduced revenue) for the same level of benefit to participating customers or, looked at another way, allow a greater benefit to be provided to eligible customers for the same "cost". The main drawback to this approach is the fact that Manitoba Hydro does not have customer-specific data regarding income levels. Furthermore, to gather such data would introduce an additional level of complexity and administrative cost as well as give rise to concerns regarding the confidentiality of personal data gathered.

On the other hand, if the Board determined that providing assistance to low income customers with space heating was required and the choice was to achieve this by offering the alternative rate design to either i) all electric heat customer or ii) just low

[248] Appendix 9.14, page 18
[249] For example, if winter was deemed to start December 1st, then a customer whose meter was read/bill issued on December 2nd, would have all of the November use classified as winter use. However, a customer whose meter was read/bill issued on November 30th would have virtually all of November classified as non-winter use.
[250] As rates will be changing with the seasons

income heat customer, then a more limited low-income targeted eligibility may even be cost-effective[251]. In addition there are likely segments of Manitoba Hydro's residential customer base that are readily identified as being low income (e.g., those already qualifying for some form of government social assistance) and, indeed, some of these may already be receiving government assistance for their electricity bill[252].

Again, it would be useful for Manitoba Hydro to undertake consumer research into the acceptability of rate designs focused just on low income electric heat customers vis-à-vis all electric heat customers and the willingness of its customer base to support such initiatives. It would also be useful for Manitoba Hydro to undertake some preliminary work regarding the cost of administering such programs.

6.2.3 Other Options Presented

During the July 2017 workshop, the Green Action Centre offered[253] a number of alternative designs targeting low income (LICO-125) customer, low income customers with electric heat and non-low income customers with electric heat. The segments targeted are similar to those discussed above and the same comments are therefore applicable.

The more unique aspect of the GAC alternatives is that, in each case, the rate structure for the targeted segment does not involve lowering the energy rate for all kWh used but rather lowering the energy rate for an initial block of kWh usage (ranging up to 500 kWh depending on the alternative). It is noted that for Residential Heat customers roughly 85% of the bills issued during the year are for consumption over 500 kWh and during the winter months this percentage increases to over 90%[254]. Thus, in terms of the rate setting objectives, this approach largely avoids the "efficiency" concerns discussed previously regarding Manitoba Hydro's Alternative Rate Design and the fact that lowering the energy charge for Residential Heat customers is inconsistent with the fact they have a higher marginal cost.

[251] Assuming the cost savings, in terms of lower lost revenues, more than offset the additional administrative costs.
[252] For example, under the Manitoba Assistance Regulation 404/88.
[253] Appendix 9.14, Attachment 3, page 5
[254] COALITION/MH II-32

The one major drawback to this approach is that virtually all customers on the rate will receive the same monthly discount in dollar terms whereas heating requirements (even for the same type of dwelling) vary widely across the province due to variation in climate. This can see from both the heating degree day map provided in response to PUB/MH II-54 and the degree day data provided in response to COALITON/MH I-89 copied below:

Degree Days Heating Summary (base 14'C)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Fiscal Year : 2016/17													
Winnipeg	336	69	11			36	246	328	848	840	672	596	3,983
Brandon	331	66	5	1		62	275	361	872	860	692	659	4,185
Dauphin	375	69	10		1	60	281	340	853	769	652	698	4,107
The Pas	399	71	4		7	74	320	370	884	807	694	729	4,359
Thompson	540	196	65	14	36	134	460	516	1,101	978	901	883	5,823
Churchill	834	431	170	97	64	166	443	577	1,103	1,080	1,020	1,030	7,014
Portage	333	51	7			33	236	303	825	782	642	619	3,832
Morden	321	52	4			31	229	294	797	767	620	591	3,705

However, a review of the degree day data flags another issue with respect to the use of alternative rate designs that vary by season, namely the months one might arguably include in defining the "heating season" varies by location. As a result, more detailed consideration of the appropriate definition for the "winter season" would be required.

6.2.4 Conclusions

When considered in the context of the various rate making objectives, the justification for the Alternative Rate Design rests almost entirely on its merits with respect to public policy and public acceptability considerations. Furthermore, a decision in favour of Alternative Rate Design would need to acknowledge (and find acceptable) the departure from cost of service/equity principles.

The Board has acknowledged that concerns regarding the impacts of higher rates on low income and electric heating customers are a matter of public interest and public policy. However, there is insufficient information regarding the public acceptability of Alternative Rate Design, particularly in view of the fact that there may be more focused alternatives available. The Board should direct that more research be undertaken in this regard.

Finally, if public policy and public acceptance are the main bases for adopting the Alternative Rate Design, a legitimate question arises as to whether cost responsibility for any lost revenue should be the responsibility of the other customers in just the Residential class or borne widely. Indeed, there appears to be little rationale for limiting the basis of recovery to just the ineligible Residential customers and widening the "recovery base" would reduce the impact associated with the recovery.

7. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations from the preceding sections are summarized below.

Change in Financial Outlook

The purpose of the Evidence was to assess whether or not Manitoba Hydro's financial outlook as presented in its current integrated financial forecasts had deteriorated significantly from that set out in earlier forecasts. This was done by comparing the results of these previous forecasts with those of IFF16 and the updated IFF16 (with the interim increase), where both are based on the rate increases assumed in IFF15.

In the case of IFF16, the forecast underpinning the initial Application, the results are mixed. In some aspects (i.e., Overall Capital Coverage) the outlook has deteriorated relative to previous forecasts. However, in other aspects it has either improved (i.e., EBITDA) or continues to be comparable with earlier forecasts (i.e., Debt Ratio). The updated version of IFF16 (with the interim increase) does show less favourable results than IFF16, particularly in the second decade of the outlook. However, continued rate increases at the level (3.95%/annum) anticipated in previous outlooks for part of the decade could offset the deterioration now also observed in the Debt Ratio.

Overall, there is no basis to conclude that the current financial outlook has significantly deteriorated from previous forecasts.

Finally, the following key drivers were identified as underlying the changes in the financial forecast:

- Manitoba Hydro's capital spending program,

- Manitoba Hydro's domestic load forecast, in particular the forecast for the Top Consumers, which account for well over half of the variation in the long term[255],
- Export prices, particularly from 2022/23 and beyond when Keeyask is in-service and Manitoba Hydro has greater volumes of energy for export. and
- Interest rate forecasts.

Regulatory Accounts

The Evidence also reviewed Manitoba Hydro's proposals with respect to the amortization of four new regulatory accounts.

For two of the regulatory accounts (Loss on Disposal and Conawapa), Manitoba Hydro's proposed treatment is reasonable and should be endorsed by the Board. However, the Board should not endorse Manitoba Hydro's proposal regarding the Ineligible Overheads or ELG/ASL Differences accounts.

In the case of the Ineligible Overheads account the amounts should be amortized over at least 30 years and, pending clarification from the Board, the deferral should not be ceased after 2022/23. In the case of the ELG/ASL Differences account, the Board should not endorse any amortization of this account until Manitoba Hydro has addressed the Board's outstanding directives on the matter and a final decision has been made as to the appropriate depreciation method for regulatory purposes.

Cost of Service Study

The Evidence reviewed Manitoba Hydro's implementation of Board Order 164/16 regarding cost of service methodology. Manitoba Hydro has generally followed the Board's principles and directives, as set out in Order 164/16, in its preparation of PCOSS18. Areas of departure are based on either a lack of data or simplifying assumptions.

Also noted are few instances where there is a mismatch between the Board's principle that "cost causation" should be the primary consideration determining the COSS methodology and a strict interpretation of the Board's directives. For some of these, refinement of the COSS treatment would have minimal effect on the results and

[255] Based on a comparison of the forecasts for 2033/34 per the 2015 and 2017 Load Forecasts

introduce additional complexities. However in a couple of cases, specifically, the functionalization of generation outlet transmission and the inclusion of radial lines in the allocation of export revenues the Board should direct Manitoba to address them in its next COSS filing.

Finally, there are a number of areas where the Board determined further study/updating are required and Manitoba Hydro has yet to address. These include:

- Directive 1 (gg) regarding the allocation of common costs and the development of allocators that are more directly related to the causes of the common costs.
- Directive 1 (v) regarding adopted the allocator for Services.
- Additional study/data regarding the appropriate treatment of primary and secondary distribution lines

Clear timelines should be established for the completion of this work and it is suggested that completion for filing with the next GRA would be appropriate.

The Evidence also looked at the use of the results of COSS studies, including the revenue to cost ratio calculation along with the purpose and appropriate range for a zone of reasonableness. It concluded that Manitoba Hydro's approach to calculating the revenue to cost ratio was reasonable. It also noted that, given the current status of the cost of service study, a broad zone of reasonableness was more appropriate.

In terms of role, the results of the cost of service study (i.e., the revenue to cost ratios) are but one input into the ultimate decision as to the rates that will be charged to a customer class and the revenues that will result. In this context, the zone of reasonableness should be used to recognize the lack of precision in the cost of service methodology and not to define the range of acceptable outcomes for the Board's overall decisions on rates and revenues by customer class. These decisions must also take into account a number of other ratemaking objectives.

It was also noted that Manitoba Hydro's requested rate increase is significantly higher than the rate of inflation and several of the ratemaking objectives would have to align or other accommodations also be made before even higher average rate increases for one or more of the customer classes could be considered.

Rate Design

The Evidence considered Manitoba Hydro's Alternative Rate Design and concluded that its justification for the Alternative Rate Design rests almost entirely on its merits with respect to public policy and public acceptability considerations. Furthermore, a decision in favour of Alternative Rate Design would need to acknowledge (and find acceptable) the departure from cost of service/equity principles.

It also concluded that there was insufficient information to regarding the public acceptability of Alternative Rate Design and that there may be more focused alternatives available. The Board should direct that more research be undertaken in this regard.

Appendix A – Statement of Qualifications and Duties – Mr. William Harper

Statement of Qualifications

William Harper received his Honours Bachelor of Science in Math and Economics from the University of Toronto in 1973. He received his Master of Applied Science in Management Science (specializing in Applied Economics and Operations Research) from the University of Waterloo in 1975. Mr. Harper is currently an Associate with Econalysis Consulting Services.

Since joining Econalysis in 2000, Mr. Harper has supported clients in Manitoba, British Columbia, Quebec, Saskatchewan and Ontario (primarily public interest groups) with their participation in regulatory proceedings on issues related to electricity utility revenue requirement determination, long-term planning (including demand-side management plans), capital project approvals, cost of service and rate design with analysis of applications and recommendations based on regulatory and economic principles.

In Manitoba, Mr. Harper has served an expert witness before the Manitoba Public Utilities Board regarding Manitoba Hydro's 2002 Status Update, 2004/05 and 05/06 General Rate Application, 2008/09 GRA, 2013 Need For And Alternatives To, and the 2015 Cost of Service Methodology Review. In addition, he appeared as an expert witness before the Manitoba Clean Environment Commission with respect the Wuskwatim Need For And Alternatives To Submission by Manitoba Hydro/Nisichawayasihk Cree Nation. He has also assisted clients in their participation in all other rate applications (General Rate Applications, Diesel or Interim) by Manitoba Hydro since 2002.

Mr. Harper has provided expert testimony before the Quebec Regie and the Ontario Energy Board on matters related to electricity regulation and rates. In addition he has served on numerous Working Groups established by the Ontario Energy Board to deal with specific cost of service and rate design policy issues and was a member of the Ontario Independent Electricity System Operator's Technical Panel from 2004 to 2010.

Prior to joining Econalysis Consulting, Mr. Harper worked at the Ontario Ministry of Energy for five as an economic analyst focussing on electricity matters and was with Ontario Hydro for 20 years. While with Ontario Hydro, he was involved in the preparation of the Company's cost of service studies and then in the preparation of the rates charged to Ontario Hydro's municipal and large industrial customers. As the Manager of Ontario Hydro's Rates Department from the years 1989 to 1995 he testified regularly before the Ontario Energy Board in annual rate proceedings. At the same time he was also responsible for Ontario Hydro's policy role in regulating the rates charged by Ontario's municipal electric utilities and the annual review of their rate applications. During his final years with Ontario Hydro/Hydro One, Mr. Harper held various positions in regulatory affairs where he was responsible for coordinating applications to the Ontario Energy Board as well as submissions to the Ontario Energy Board regarding its new role in regulating the restructured Ontario electricity industry.

Mr. Harper will rely on his expertise in regulatory, cost of service and rate design principles and practices in this proceeding relating to Manitoba Hydro.

Duties

The following duties were assigned to Mr. Harper in the Manitoba Hydro 2017/18 and 2018/19 General Rate Application.

The Public Interest Law Centre retained Mr. Harper's services to assist the Consumers Coalition with its participation in the Public Utilities Board review of Manitoba Hydro's Application on issues related to the Interim Rate Request, Economic Outlook – Forecast Assumptions, Operation, Maintenance and Administration costs, Regulatory Deferral Accounts, Rate Design, as well as the implementation of the Cost of Service Order and its implications for rate-setting.

Mr. Harper's duties include:

- Reviewing the evidence, identifying initial issues, briefing the clients, assisting the Public Interest Law Centre with the work plan;
- Providing support for the interim rate request process;
- Preparing first round of Information Request for the GRA;
- Reviewing Information Request responses & preparing second round of Information Requests for the GRA;
- Preparing Econalysis Consulting Service Evidence;
- Reviewing Intervener evidence, preparing Information Requests;
- Providing cross-examination support;
- Preparing for and attending the hearing for the provision of Econalysis Consulting Service expert evidence; and,
- Providing support for final submissions.

Mr. Harper's retainer letter includes that he is to provide evidence that:

- is fair, objective and non-partisan;
- is related only to matters that are within his area of expertise; and
- to provide such additional assistance as the Public Utilities Board may reasonably require to determine an issue.

Mr. Harper's retainer letter also includes that his duty in providing assistance and giving evidence is to help the Public Utilities Board. This duty overrides and obligation to the Consumers Coalition.

APPENDIX B

COALITION'S COMMENTS RE:

MANITOBA HYDRO's COSS COMPLIANCE FILING

PUBLIC
INTEREST
LAW
CENTRE

CENTRE
JURIDIQUE
DE
L'INTÉRÊT
PUBLIC

AN INDEPENDENT SERVICE OF LEGAL AID MANITOBA

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April 28, 2017

Mr Kurt Simonsen,
Associate Secretary
Public Utilities Board
Room 400, 330 Portage Avenue
Winnipeg, MB R3C 0C4

Dear Mr Simonsen:

Re: Manitoba Hydro Compliance Filing as Required in Order 164/16

Please find attached the comments of the Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (together, the Consumer Coalition) with regard to Manitoba Hydro's Compliance Filing as required in Order 164/16.

Please do not hesitate to contact me should you have any questions.

Yours truly,

for: BYRON WILLIAMS
DIRECTOR

BW/km

cc: Manitoba Hydro
Board Counsel
All Intervenors from COSS Methodology Review

REVIEW OF MANITOBA HYDRO'S ORDER 164/16 COMPLIANCE FILING

SUMMARY OF FINDINGS

INTRODUCTION

On December 4, 2015 Manitoba Hydro filed an Application with the PUB for review and consideration of its Cost of Service (COS) Methodology. On December 20, 2016 the PUB issued Order 164/16 regarding the Application which directed that: i) a number of revisions be made to the COS Methodology and ii) Manitoba Hydro provide a compliance filing based on PCOSS14-Amended (which was the basis of initial Application) that reflected all of the Board's findings and directions in the Order. The compliance filing was submitted to the PUB on February 21, 2017.

On April 3, 2017 the PUB provided a response to Manitoba Hydro's compliance filing which: i) identified a number of items that it required follow-up and/or clarification in Manitoba Hydro's next general rate application (GRA) and ii) invited comments from Parties to the original proceeding.

PILC (on behalf of the Consumer Coalition) requested that Mr. Harper, an Associate with Econalysis Consulting Services, review the compliance filing and provide comments as to is conformance with Board Order 164/16. The following summarizes the result of the assessment and classifies Manitoba Hydro adherence to the Board's Directives in to the following four categories:

1. Those Directives where it is clearly verifiable, from the compliance filing, that they have been appropriately addressed by Manitoba Hydro.
2. Those Directives where, while Manitoba Hydro has indicated its compliance filing reflects the Board's direction, there is insufficient information provided to fully verify this to be the case.
3. Those Directives where some issues/questions have been noted regarding Manitoba Hydro's implementation of the Board's Directive.
4. Those Directives that Manitoba Hydro has indicated it has not yet addressed by will do so in the preparation of PCOSS18.

The assessment also identified a few other issues regarding Order 164/16 that should be considered at the next GRA.

CATEGORY 1: Directives Where Compliance is Verifiable

Set out below is a list of the Board Directives where the compliance filing provided sufficient information to clearly demonstrate conformance with the Board's directions:

- Directive 1 a)
- Directive 1 b)
- Directive 1 d)
- Directive 1 e)
- Directive 1 g)
- Directive 1 h)
- Directive 1 i)
- Directive 1 k)
- Directive 1 l)
- Directive 1 m)
- Directive 1 o)
- Directive 1 q)
- Directive 1 r)
- Directive 1 s)
- Directive 1 t)
- Directive 1 u)
- Directive 1 v) – Interim approach
- Directive 1 x)
- Directive 1 aa)
- Directive 1 hh)

CATEGORY 2: Directives Where Compliance Is Not Fully Verifiable

Set out below is a list of those Directives where it was not possible (due to a lack of detail provided) to fully verify either that the Directive was implemented as intended and/or how it was implemented.

- Directive 1 c) - In the compliance filing \$36,314 k out of a total of \$119,022 k in water rentals and variable hydraulic operating and maintenance costs were deducted from gross export revenues[1]. However, the compliance filing does not set out how the portions of water rentals and variable hydraulic operating and maintenance costs associated with exports were determined.
- Directive 1 bb) - Manitoba Hydro's February 21, 2017 letter indicates that the compliance filing reflects this directive and, as noted in the PUB's letter of April 3, 2017 the revenues by customer class in the compliance filing are very close to those one would expect given Mr. Harper's evidence. However, insufficient details have been provided regarding the development of the revised revenues by customer class to fully verify this (e.g., the equivalent of Schedule 13 per PCOSS14-Amended and the derivation of the allocation factors used).
- Directive 1 cc) - It is evident from the compliance filing that Manitoba Hydro's labour costs (i.e., operating costs net of power purchases, fuel and water rentals) have been used to allocate the interest and capital taxes attributed to Building and Common Equipment to functions.

  In the case of depreciation and operating costs, it is understood that they are generally tracked via Settlement Cost Centres (SCCs) in sufficient detail to be assigned to functions. However, no details have been provided as to how their assignment to functions was changed in the compliance filing and, therefore, whether it is consistent with the Board's directives.
- Directive 1 dd) - The interest and capital taxes attributable to Communications and Control common costs (excluding communications for system control purposes) are allocated to all functions except Customer Services using the

[1] Electronic COS Model, Allocated Costs Tab

labour allocator as per the Board's directive. The interest and capital taxes attributable to communications for system control purposes are allocated to Generation/Transmission/Subtransmission in a 36/28/36 proportion, which Manitoba Hydro has indicated it will update for the next GRA.

In the original PCOSS14-Amended similar approaches were used for the depreciation and operating costs associated with Communications and Control. However, for these costs, it is not readily apparent from the material provided how they were functionalized in the compliance filing and whether the approach used was consistent with the PUB's direction.

CATEGORY 3 – Issues/Questions Noted Regarding the Compliance Filing

Set out below is a list of those Directives where specific issues/questions have been identified regarding the compliance filing's implementation of the Board's directions.

- Directive 1 f) - A comparison of the Average Rate Base (for Finance and Reserves) in the COS model provided with the compliance filing shows an increase of $11 M in Transmission lines now functionalized as Generation consistent with the lines identified in Directive 1 f) iii). However the increase in Substation (non-HVDC) costs (~$11 M) functionalized as Generation is less than the $14 M value for the Pointe du Bois switching station. In the Compliance filing the Non-Tariff portion of Substation costs has declined by $14 –consistent with the removal of the Pointe du Bois substation. However, the Tariffable Substation assets functionalized as Transmission have increased by $3 M in the compliance filing (with an offsetting decrease in Generation) and it is not clear why.

  Also, as noted in the PUB's letter of April 3, 2017, it does not appear that the MISO fees were functionalized as Generation per the Board's Order.

- Directive j) - As noted in the preceding discussion regarding Directive 1 f), in the compliance filing the Tariffable Substation (non-HVDC) costs have increased by $3 M (vis-à-vis PCOSS14-Amended) and it is not clear why.

- Directive 1 n) – The total value of the assets functionalized as Subtransmission has changed from that in PCOSS14-Amended. One reason appears to be that the operating costs used to assign Common costs have changed from the corrected values provided in COALITION/MH I-35 a). However, it is not clear why the operating costs attributable to Subtransmission should change in the compliance filing since the definition of Subtransmission does not appear to have changed from that used in PCOSS14-Amended.

- Directive 1 p) – Similarly, the total value of the assets functionalized as Distribution has changed from that in PCOSS14-Amended. Again, one reason appears to be that the operating costs used to assign Common costs have changed from the corrected values provided in COALITION/MH I-35 a). However, (again) it is not clear why the operating costs attributable to Distribution should change in the compliance filing since the definition of Distribution does not appear to have changed from that used in PCOSS14-Amended.
- Directive 1 y) – As noted by the PUB in its April 3, 2017 letter Manitoba Hydro has only indirectly complied with the PUB's directive not to allocate any of the Customer Service sub-category of Customer Consultation and Information costs to the GSL 30-100 and GSL>100 classes such that the approach used in not mathematically equivalent to the intent of the directive.

<u>CATEGORY 4 – Directives Manitoba Hydro Will Comply with in PCOSS18</u>

In its February 21, 2017 letter Manitoba Hydro acknowledged that there were a number of Directives it had not addressed in the compliance filing but it planned to address as part of its preparation of PCOSS18:

- Directive 1 v) – Update allocator weightings
- Directive 1 w)
- Directive 1 y) – Update allocation factors
- Directive 1 z)
- Directive 1 ee)
- Directive 1 ff)
- Directive 1 gg)

OTHER MATTERS

In its April 3, 2017 letter the PUB noted that while it had directed (Directive 1 f)) that all MISO fees be functionalized as Generation, some of the cost may be related to and therefore should remain functionalized as Transmission. There are a couple of other PUB directives that could be refined given the principles the Board set out in Order 164/16 and used as the rationale for the subsequent Directives:

- Directive 1 b) - The PUB's rationale for crediting Export Revenue based on Generation and Transmission costs was based on the view[2] that these are the only functions utilized to effect export sales and that the Distribution system is not utilized to effect export sales. However, it is noted that a small portion of export revenues[3] ($749 k) are associated with charges to retail customers situated outside of Manitoba that are served by way of connection to the Manitoba Hydro distribution system[4]. As a result, in accordance with the principles set out in Order 164/16, this portion of export revenue could be allocated based on Generation, Transmission, Subtransmission and Distribution. This is a matter which could be explored in the next GRA.

  It is also noted that the cost of Transmission includes the cost of radial taps ($211 k) used to serve GS>100 customers and allocated directly to them (per Directive 1 m)). Since these lines only service retail customers and are non-tariffable (vis-à-vis the OATT) their inclusion in the allocation base is inconsistent with the PUB's rationale for using Generation and Transmission as the allocation base for export revenue. Again, this is a matter that could be explored at the next GRA.

- Directive 1 v) - The Board, in formulating this directive, relied on the written evidence of Mr. Harper (Order 164/16, pages 76-77). However, during the Oral Phase of the proceeding, Mr. Harper agreed that there were issues with his proposal and that another approach (proposed by Mr. Chernick) would be a

[2] Order 164/16, pages 36-37
[3] PCOSS14-Amended, Schedule C13
[4] COALITION/MH I- 3 a) – c)

better way to do it (see June 21, 2016 Transcript, page 418). This could be explored at the next GRA