360 Portage Avenue (22) · Winnipeg Manitoba Canada · R3C 0G8
Telephone / N° de téléphone: (204) 360-3257 · Fax / N° de télécopieur: (204) 360-6147 · baczarnecki@hydro.mb.ca

March 10, 2023

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Dr. D. Christle, Board Secretary and Executive Director

Dear Dr. Christle:

RE: MANITOBA HYDRO'S 2023/24 & 2024/25 GENERAL RATE APPLICATION – MANITOBA HYDRO'S RESPONSES TO ROUND 2 INFORMATION REQUESTS

Please find enclosed Manitoba Hydro's responses to Round II Information Requests (IRs) issued by the Public Utilities Board ("PUB"), the Assembly of Manitoba Chiefs ("AMC"), the Consumer Coalition (Manitoba Branch of the Consumers' Association of Canada, Harvest Manitoba, Aboriginal Council of Winnipeg) ("Coalition"), the General Service Small and General Service Medium Customer Classes ("GSS/GSM"), the Manitoba Industrial Power Users Group ("MIPUG"), and the Manitoba Keewatinowi Okimakanak Inc. ("MKO").

As part of the Round II IR process, Manitoba Hydro received over 650 individual questions, bringing the total IR count in this proceeding to over 2,300. Manitoba Hydro's view was that certain Round II IRs were not a follow up to Round I IRs as was directed by the PUB. Despite this, Manitoba Hydro has answered all IRs submitted, such to avoid the potential of any procedural motions and delays to the hearing process and timetable.

The answers to Round II IRs consist of approximately 1,400 pages of evidence. This brings the total amount of pages filed in response to information requests to over 6,100 pages. This is in addition to that which was initially filed by Manitoba Hydro in the Application, including addressing the PUB's Minimum Filing Requirements.

A summary of the total IR count received by party for this proceeding is:

Intervener	Number of Questions
PUB	593
AMC	115
COALITION	1031
GSS/GSM	86
MIPUG	450
MKO	31
Total	**2,306**

Pursuant to Order 130/22, Manitoba Hydro is filing responses to Information Requests containing confidential information with the PUB and has provided redacted copies herein. Manitoba Hydro has relied upon the same redaction criteria which have been considered and relied upon by the PUB in previous applications and has inserted codes corresponding to the categories in the Redaction Criteria directly in the responses to the information Requests. For ease of reference, attached hereto as Appendix A is a copy of the Redaction Criteria.

The following attachments are provided in Excel format. Where the Excel document was readily available, Manitoba Hydro has provided these documents to the PUB and registered interveners.

- Coalition/MH II-100 a)
- Coalition/MH II-100 b)
- Coalition/MH II-100 d) (contains CSI and as such is provided to PUB and Daymark only)
- GSS-GSM-MH II-1
- MIPUG/MH II-12 a)
- MIPUG/MH II-12 b)
- MIPUG-MH II-19a-c
- PUB/MH II-42 e)
- PUB/MH II-42 f)

<u>Revised Materials</u>

The following list of documents have been revised to provide minor corrections to the original response and can be found enclosed.

- PUB MFR 51 – correction to certain data in Figure 1
- AMC/MH I-30 a)-c) – correction to data in parts b) and c)
- COALITION/MH I-138 a)-h) – adjusted to update sub-part bullets for clarity and corrections to schedules on pages 11-14.
- GSS-GSM/MH I-6 a)-k) – correction to Figure 3
- MIPUG/MH I-91 a)-dd) – Att. 2- update to correct accounting standards used for Hydro One
- PUB/MH I-140 a)-c) – correction to table in part c)

In its Round I IR responses filed on February 3, 2023, Manitoba Hydro advised that it would update the response to PUB/MH I-43 when the 2022 marginal values were available, and would provide a response to COALITION/MH I-36 d) at the time of filing Round II IRs. Enclosed please find Manitoba Hydro's updated responses to PUB/MH I-43 a)-e) and the response to COALITION/MH I-36 d).

Manitoba Hydro has also updated these responses on its external website.

Should you have any questions with respect to the foregoing, please do not hesitate to contact the writer at 204-360-3257.

Yours truly,
MANITOBA HYDRO LEGAL SERVICES
Per:

Brent Czarnecki
Senior Counsel

Manitoba Hydro Redaction Criteria

1 **Party/Contract Specific Detail (information provided to MH with an expectation that confidentiality will be maintained)** *for example:*

- **a.** Detailed business arrangements with third parties to construct/operate/own facilities.
- **b.** Specific pricing, terms, conditions in contracts or third-party responses to request for proposals related to the construction procurement of a generation, transmission or distribution resource on the MH system;
- **c.** Specific domestic customer load information, current or forecast;
- **d.** Specific affected parties including mitigation or compensation not already available in public forum;
- **e.** Information subject to statutory or contractual confidentiality provisions.

2 **Technical Information or Intellectual Property**

- **a.** Owned by Manitoba Hydro e.g. Consensus Export Price Forecast
- **b.** Owned by a third party

3 **Power Contracts, Revenue & Price Forecast Information** *for example:*

- **a.** Specific data, forecast, terms, conditions, prices, revenue projections contained in reports, agreements, contracts, proposals, term sheets together with information which facilitates back calculation of the foregoing information;
- **b.** MH commodity price forecasts for electricity, natural gas and carbon including annual pricing escalators including third party proprietary input forecasts;

4 **Documents Related to Risk/Benefit Identification, Quantification and Strategic Actions** *for example:*

- **a.** Sales and marketing strategies/initiatives;
- **b.** Identification of risks and benefits with details on relative significance, quantification, strategic actions and timeframes. Identification of specific parties who have an interest in or ability to influence the risk/benefit outcomes.

5 **Sensitive Analysis and Operational Data Facilitating Back Calculation** *for example:*

- **a.** Resource planning assumptions and analysis including the generation component of marginal cost;
- **b.** Committed and uncommitted capacity and energy surplus quantities for export;
- **c.** Breakdown of export sales quantity or revenue by product type, customer or province.

6 **Utility Practice Techniques** *for example:*

- **a.** Detailed solution techniques utilized in MH's short- and long-term planning of capacity, energy and water management with specific reference to the mathematical representation of the hydraulic or transmission system and the electricity market.

7 **Resource, Project or Sale Cost and Benefit Analysis where such information could negatively impact Manitoba Hydro's negotiating power** for *example:*

- **a.** Detailed cost estimates of new resources planned or in development on MH system, budget and contingency information related to projects and/or specific project components;
- **b.** Estimate of economic or financial benefits (i.e., Net Present Value, revenue projections, Internal Rate of Return) of development plans or sales evaluations.

8 **Sensitive Relationship Management Information** *for example:*

- **a.** Employment, labour relations, counterparty or stakeholder information, which if disclosed could result in labour issues, work stoppages, contract breach or demands for renegotiation

9 **Centra Gas Sensitive Information** for example:

- **a.** a. Natural gas load forecast information and impact of weather on Manitoba market demand and gas supply operations (i.e., Effective Heating Degree-Day (EHDD) balance point, actual and forecast EHDD).

REFERENCE:

Application Tab 6, pages 44-45

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has experienced an increase in uncollectible accounts. In April 2020, Manitoba Hydro announced that Manitobans would be granted a suspension of late payment charges on their electric and gas bills for up to six months. Manitoba Hydro also discontinued the disconnection of customers for non-payment. There has been a significant increase in customers who are unable to pay their Manitoba Hydro accounts and a significant increase in customer arrears.

Over a two-year period during the pandemic, arrears over 90 days for electric customers increased 80% or approximately $23 million. By the end of the fiscal 2021/22 year the expected credit loss allowance had increased by approximately $8 million and resulted in Manitoba Hydro recording a bad debt expense of $6 million. Manitoba Hydro is not expecting a further spike in uncollectible accounts.

QUESTION:

a) Has Manitoba Hydro re-instated late payment charges on electric and gas bills and re-started disconnection for customers who are unable to pay their accounts? If yes, what is the total amount of late payment charges that Manitoba Hydro has collected each year for the last five fiscal years?
b) Please provide the number of uncollectible accounts for First Nations on-reserve customers for each of the last five fiscal years.
c) Please provide the number of disconnected accounts for First Nations on-reserve customers for each of the last five years.

RESPONSE:

a) Yes, Manitoba Hydro re-instated late payment charges and disconnections. The total for late payment charges for all customers collected per fiscal year is as follows:

Fiscal Year	Late Payment Charges Collected
2018	$559,000
2019	$1,219,000
2020	$1,688,500
2021	$2,861,500
2022	$4,481,000

b) The number First Nation, on reserve accounts transitioned to an uncollectable status are as follows:

Fiscal Year	Uncollectable Accounts
2018	677
2019	303
2020	189
2021	500
2022	346

c) The number of First Nation, on reserve accounts disconnected by Fiscal year is as follows:

Fiscal Year	Disconnected Accounts
2018	1881
2019	2261
2020	1777
2021	3
2022	371

REFERENCE:

Tab 4, Section 4.4, Figure 4.3.4, pg. 40, Appendix 4.4, PUB/MH II-39 from the MH 2018/19 GRA and Appendix 3.6, Figure 3.6.1 from the MH 2015/16 GRA.

PREAMBLE TO IR (IF ANY):

MH provides a summary of the projected debt ratios for a number of one-off risk sensitivities and three (3) alternate rate scenarios in Figure 4.3.4 and a number of other financial metrics for the sensitivities and rate scenarios in Appendix 4.4.

QUESTION:

d) Please provide both a Low and High Domestic Load growth risk sensitivity similar to that which was provided in the response to PUB/MH II-39 from the MH 2018/19 GRA.

RESPONSE:

In order to respond to the question, a high and low load was created leveraging the similar methodology utilized during the Manitoba Hydro 2017/18 & 2018/19 GRA. Historic load variability has been analyzed using a probabilistic-based approach to provide an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations), also known as P10 and P90, form the Low and High Load Forecast Sensitivities.

Manitoba Hydro notes the load growth risk sensitivity represents an extended period of high or low economic growth resulting in a proportional increase/decrease in the load in all hours – summer and winter. In other words, energy and capacity demand increase/ decrease at comparable annual growth rates. While it is still premature, these sensitivities may not capture the full extent/possible range of the changing energy landscape and they should be considered with caution.

To develop the financial forecast sensitivities for the purposes of this IR, supply/demand scenarios were prepared with new resources to meet expected demand in a similar manner to the 2022 Supply/Demand Scenario outlined in Tab 5. Figure 1 below summarizes when persistent capacity and energy deficits are anticipated to begin under both the low and high electricity load forecast sensitivities assuming no new resources. The financial analysis for the low and high electricity load forecast sensitivities begins in 2025/26.

Figure 1 Energy & Capacity Need Dates Assuming No New Resources

Sensitivity	Energy Need Date	Capacity Need Date
High Electricity Load Forecast Sensitivity	2031/32	2023/24
2022 Planning Assumptions (MFR 43)	2033/34	2030/31
Low Electricity Load Forecast Sensitivity	2036/37	2036/37

Refurbishments/supply side enhancements and demand response assumptions included in the 2022 Supply/Demand Scenario (Tab 5, Section 5.9) remain unchanged in the two load forecast sensitivities, while proxy resources (wind PPAs and dispatchable capacity resources) were either advanced or deferred to keep supply and demand in balance.

The supply/demand scenario in the high electricity load forecast sensitivity is primarily balanced assuming the addition of wind generation for energy and natural gas generation for capacity and drought support. No additional capital costs are included to meet potential federal Environment and Climate Change Canada (ECCC) Clean Electricity Regulations (CER) that are still under development as discussed at page 8 of Tab 2 of the Application. As noted in Tab 2 these potential regulations are likely to rule out significant use of new unabated natural gas units (i.e., without carbon capture and storage); the extent to which new natural gas units can be relied upon will not be known until draft regulations are finalized and published.

Over the 20-year planning horizon, the high electricity load forecast scenario projects total domestic revenue that is $2.1 billion higher and net export revenue that is $1.2 billion lower compared to the Amended Financial Forecast Scenario. Expenses (O&A, Net Finance, Depreciation & Amortization and Taxes) are $0.6 billion higher over the 20-year planning horizon due to the earlier need dates for new energy and capacity resources. By 2041/42, cumulative net income under the high electricity load forecast scenario is only $0.3 billion higher and the debt ratio is largely unchanged. As noted above, these sensitivities may not capture the full extent/possible range of the changing energy landscape and they should be considered with caution.

Over the 20-year planning horizon, the low electricity load forecast scenario projects total domestic revenue that is $2.1 billion lower and net export revenue that is $1.3 billion higher compared to the Amended Financial Forecast Scenario. Expenses (O&A, Net Finance, Depreciation & Amortization and Taxes) are $0.2 billion lower over the 20-year planning horizon due to the later need dates for new energy and capacity resources. By 2041/42, cumulative net income under the low electricity load forecast scenario is $0.6 billion lower and the debt ratio is 1% higher.

A summary of the key financial measures similar to that found in Appendix 4.4 are provided below for the low and high electricity load forecast sensitivities.

Incremental Increase/(Decrease) from Financial Forecast Scenario Debt Ratio (%) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**85%**	**83%**	**82%**	**82%**	**81%**	**81%**	**80%**	**80%**	**79%**	**79%**	**78%**	**77%**	**76%**	**75%**	**73%**	**72%**	**71%**	**70%**	**68%**	**66%**
Low Electricity Load Forecast Sensitivity	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	2%	3%	2%	1%	1%	1%	1%
High Electricity Load Forecast Sensitivity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Debt Ratio (%) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**85%**	**83%**	**82%**	**82%**	**81%**	**81%**	**80%**	**80%**	**79%**	**79%**	**78%**	**77%**	**76%**	**75%**	**73%**	**72%**	**71%**	**70%**	**68%**	**66%**
Low Electricity Load Forecast Sensitivity	85%	83%	82%	82%	81%	81%	81%	81%	80%	80%	79%	79%	78%	77%	76%	74%	72%	71%	69%	67%
High Electricity Load Forecast Sensitivity	85%	83%	82%	81%	81%	80%	80%	80%	79%	79%	78%	77%	76%	75%	73%	72%	71%	70%	68%	66%

Incremental Increase/(Decrease) from Financial Forecast Scenario Retained Earnings (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 3 575**	**$ 4 044**	**$ 4 339**	**$ 4 488**	**$ 4 654**	**$ 4 751**	**$ 4 843**	**$ 4 953**	**$ 5 058**	**$ 5 227**	**$ 5 417**	**$ 5 635**	**$ 5 912**	**$ 6 162**	**$ 6 444**	**$ 6 753**	**$ 7 112**	**$ 7 551**	**$ 8 058**	**$ 8 628**
Low Electricity Load Forecast Sensitivity	0	(0)	(0)	(27)	(71)	(119)	(162)	(195)	(252)	(305)	(360)	(419)	(480)	(527)	(570)	(578)	(579)	(588)	(594)	(598)
High Electricity Load Forecast Sensitivity	0	(0)	(0)	23	38	64	108	163	181	180	179	184	183	189	195	221	252	254	282	312

Retained Earnings (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 3 575**	**$ 4 044**	**$ 4 339**	**$ 4 488**	**$ 4 654**	**$ 4 751**	**$ 4 843**	**$ 4 953**	**$ 5 058**	**$ 5 227**	**$ 5 417**	**$ 5 635**	**$ 5 912**	**$ 6 162**	**$ 6 444**	**$ 6 753**	**$ 7 112**	**$ 7 551**	**$ 8 058**	**$ 8 628**
Low Electricity Load Forecast Sensitivity	3 575	4 044	4 339	4 462	4 583	4 632	4 681	4 759	4 806	4 922	5 057	5 216	5 433	5 635	5 874	6 175	6 532	6 963	7 464	8 030
High Electricity Load Forecast Sensitivity	3 575	4 044	4 339	4 512	4 692	4 815	4 951	5 116	5 239	5 407	5 596	5 819	6 095	6 350	6 639	6 975	7 364	7 804	8 340	8 939

Incremental Increase/(Decrease) from Financial Forecast Scenario Net Income (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 751**	**$ 469**	**$ 295**	**$ 149**	**$ 166**	**$ 97**	**$ 92**	**$ 111**	**$ 105**	**$ 169**	**$ 190**	**$ 219**	**$ 277**	**$ 250**	**$ 282**	**$ 309**	**$ 358**	**$ 439**	**$ 507**	**$ 569**
Low Electricity Load Forecast Sensitivity	(0)	0	0	(27)	(45)	(47)	(43)	(33)	(57)	(53)	(55)	(59)	(61)	(48)	(43)	(8)	(1)	(9)	(6)	(3)
High Electricity Load Forecast Sensitivity	(0)	0	0	23	15	26	44	55	18	(1)	(1)	5	(1)	6	6	27	31	1	28	30

Net Income (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 751**	**$ 469**	**$ 295**	**$ 149**	**$ 166**	**$ 97**	**$ 92**	**$ 111**	**$ 105**	**$ 169**	**$ 190**	**$ 219**	**$ 277**	**$ 250**	**$ 282**	**$ 309**	**$ 358**	**$ 439**	**$ 507**	**$ 569**
Low Electricity Load Forecast Sensitivity	751	469	295	122	121	49	49	78	47	116	134	160	216	202	239	301	357	430	501	566
High Electricity Load Forecast Sensitivity	751	469	295	173	181	122	136	166	123	168	189	224	276	256	288	336	389	441	536	599

Incremental Increase/(Decrease) from Financial Forecast Scenario Net Debt (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 22 963**	**$ 22 529**	**$ 22 341**	**$ 22 371**	**$ 22 322**	**$ 22 356**	**$ 22 401**	**$ 22 451**	**$ 22 471**	**$ 22 424**	**$ 22 372**	**$ 22 270**	**$ 22 090**	**$ 22 030**	**$ 22 063**	**$ 21 983**	**$ 21 798**	**$ 21 656**	**$ 21 355**	**$ 20 930**
Low Electricity Load Forecast Sensitivity	0	0	(0)	27	71	98	119	125	156	180	206	234	263	176	(67)	(270)	(327)	(359)	(384)	(414)
High Electricity Load Forecast Sensitivity	0	0	(0)	(23)	(38)	53	166	269	415	455	463	471	487	502	526	547	568	592	715	780

Net Debt (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 22 963**	**$ 22 529**	**$ 22 341**	**$ 22 371**	**$ 22 322**	**$ 22 356**	**$ 22 401**	**$ 22 451**	**$ 22 471**	**$ 22 424**	**$ 22 372**	**$ 22 270**	**$ 22 090**	**$ 22 030**	**$ 22 063**	**$ 21 983**	**$ 21 798**	**$ 21 656**	**$ 21 355**	**$ 20 930**
Low Electricity Load Forecast Sensitivity	22 963	22 529	22 341	22 398	22 394	22 454	22 520	22 576	22 627	22 604	22 578	22 504	22 353	22 206	21 997	21 714	21 471	21 297	20 971	20 516
High Electricity Load Forecast Sensitivity	22 963	22 529	22 341	22 347	22 285	22 409	22 567	22 720	22 886	22 878	22 835	22 741	22 578	22 532	22 589	22 530	22 366	22 248	22 070	21 710

Incremental Increase/(Decrease) from Financial Forecast Scenario Cash Surplus/(Deficiency) (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 310**	**$ 465**	**$ 174**	**$ (17)**	**$ 45**	**$ (33)**	**$ (47)**	**$ (49)**	**$ (19)**	**$ 50**	**$ 56**	**$ 106**	**$ 184**	**$ 65**	**$ (28)**	**$ 86**	**$ 190**	**$ 147**	**$ 306**	**$ 430**
Low Electricity Load Forecast Sensitivity	(0)	(0)	(0)	(27)	(45)	(27)	(21)	(7)	(30)	(24)	(26)	(28)	(29)	87	242	203	57	32	25	30
High Electricity Load Forecast Sensitivity	(0)	(0)	(0)	23	14	(91)	(112)	(103)	(146)	(40)	(8)	(8)	(17)	(14)	(24)	(21)	(21)	(24)	(123)	(65)

Cash Surplus/Deficiency (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**$ 310**	**$ 465**	**$ 174**	**$ (17)**	**$ 45**	**$ (33)**	**$ (47)**	**$ (49)**	**$ (19)**	**$ 50**	**$ 56**	**$ 106**	**$ 184**	**$ 65**	**$ (28)**	**$ 86**	**$ 190**	**$ 147**	**$ 306**	**$ 430**
Low Electricity Load Forecast Sensitivity	310	465	174	(44)	0	(60)	(68)	(56)	(49)	26	30	78	155	152	214	289	248	180	331	461
High Electricity Load Forecast Sensitivity	310	465	174	6	59	(124)	(159)	(153)	(165)	10	48	99	167	51	(52)	64	169	124	183	365

Incremental Increase/(Decrease) from Financial Forecast Self-Financing Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**140%**	**165%**	**125%**	**98%**	**106%**	**96%**	**94%**	**94%**	**98%**	**105%**	**106%**	**111%**	**118%**	**106%**	**98%**	**107%**	**116%**	**111%**	**124%**	**134%**
Low Electricity Load Forecast Sensitivity	0%	0%	0%	-4%	-6%	-4%	-3%	-1%	-4%	-3%	-3%	-3%	-2%	10%	24%	22%	6%	3%	3%	4%
High Electricity Load Forecast Sensitivity	0%	0%	0%	3%	2%	-9%	-11%	-9%	-13%	-4%	-1%	-1%	-2%	-1%	-2%	-2%	-2%	-2%	-11%	-7%

Self-Financing Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**140%**	**165%**	**125%**	**98%**	**106%**	**96%**	**94%**	**94%**	**98%**	**105%**	**106%**	**111%**	**118%**	**106%**	**98%**	**107%**	**116%**	**111%**	**124%**	**134%**
Low Electricity Load Forecast Sensitivity	140%	165%	125%	94%	100%	92%	92%	93%	94%	103%	103%	108%	116%	116%	122%	129%	122%	114%	127%	138%
High Electricity Load Forecast Sensitivity	140%	165%	125%	101%	108%	86%	84%	85%	84%	101%	105%	110%	116%	104%	96%	105%	113%	109%	113%	127%

Incremental Increase/(Decrease) from Financial Forecast Scenario Cash Flow to Net Debt Ratio (%) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**5%**	**5%**	**4%**	**3%**	**3%**	**3%**	**3%**	**4%**	**4%**	**4%**	**5%**	**5%**	**5%**	**5%**	**6%**	**6%**	**6%**	**7%**	**7%**	**8%**
Low Electricity Load Forecast Sensitivity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
High Electricity Load Forecast Sensitivity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Cash Flow to Net Debt Ratio (%) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**5%**	**5%**	**4%**	**3%**	**3%**	**3%**	**3%**	**4%**	**4%**	**4%**	**5%**	**5%**	**5%**	**5%**	**6%**	**6%**	**6%**	**7%**	**7%**	**8%**
Low Electricity Load Forecast Sensitivity	5%	5%	4%	3%	3%	3%	3%	3%	4%	4%	4%	5%	5%	5%	5%	6%	6%	7%	7%	8%
High Electricity Load Forecast Sensitivity	5%	5%	4%	3%	4%	4%	4%	4%	4%	4%	5%	5%	5%	5%	6%	6%	6%	7%	7%	8%

Incremental Increase/(Decrease) from Financial Forecast Scenario EBITDA Interest Coverage Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**2.48**	**2.21**	**2.06**	**1.92**	**1.95**	**1.89**	**1.90**	**1.95**	**1.99**	**2.12**	**2.17**	**2.24**	**2.33**	**2.36**	**2.44**	**2.53**	**2.64**	**2.79**	**2.92**	**3.07**
Low Electricity Load Forecast Sensitivity	0.00	(0.00)	0.00	(0.03)	(0.05)	(0.05)	(0.05)	(0.04)	(0.07)	(0.07)	(0.07)	(0.08)	(0.09)	(0.08)	(0.07)	(0.03)	(0.02)	(0.02)	(0.01)	(0.01)
High Electricity Load Forecast Sensitivity	0.00	(0.00)	0.00	0.02	0.01	0.02	0.04	0.05	0.01	(0.01)	(0.01)	(0.00)	(0.01)	(0.00)	(0.01)	0.00	0.00	(0.02)	(0.01)	(0.02)

EBITDA Interest Coverage Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**2.48**	**2.21**	**2.06**	**1.92**	**1.95**	**1.89**	**1.90**	**1.95**	**1.99**	**2.12**	**2.17**	**2.24**	**2.33**	**2.36**	**2.44**	**2.53**	**2.64**	**2.79**	**2.92**	**3.07**
Low Electricity Load Forecast Sensitivity	2.48	2.21	2.06	1.89	1.90	1.84	1.85	1.91	1.92	2.05	2.10	2.16	2.25	2.28	2.37	2.49	2.62	2.77	2.91	3.07
High Electricity Load Forecast Sensitivity	2.48	2.21	2.06	1.94	1.96	1.92	1.95	1.99	2.00	2.11	2.17	2.24	2.32	2.36	2.43	2.53	2.65	2.77	2.91	3.05

Incremental Increase/(Decrease) from Financial Forecast Scenario EBIT Interest Coverage Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**1.80**	**1.51**	**1.32**	**1.16**	**1.18**	**1.10**	**1.10**	**1.11**	**1.11**	**1.18**	**1.20**	**1.23**	**1.29**	**1.27**	**1.30**	**1.33**	**1.39**	**1.48**	**1.57**	**1.65**
Low Electricity Load Forecast Sensitivity	(0.00)	(0.00)	(0.00)	(0.03)	(0.05)	(0.05)	(0.05)	(0.03)	(0.06)	(0.06)	(0.06)	(0.06)	(0.07)	(0.05)	(0.05)	(0.01)	0.00	(0.00)	0.00	0.01
High Electricity Load Forecast Sensitivity	(0.00)	(0.00)	(0.00)	0.03	0.02	0.03	0.05	0.05	0.02	(0.01)	(0.01)	(0.00)	(0.01)	(0.00)	(0.00)	0.02	0.02	(0.01)	0.01	0.01

EBIT Interest Coverage Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**1.80**	**1.51**	**1.32**	**1.16**	**1.18**	**1.10**	**1.10**	**1.11**	**1.11**	**1.18**	**1.20**	**1.23**	**1.29**	**1.27**	**1.30**	**1.33**	**1.39**	**1.48**	**1.57**	**1.65**
Low Electricity Load Forecast Sensitivity	1.80	1.51	1.32	1.13	1.13	1.05	1.05	1.08	1.05	1.12	1.14	1.17	1.22	1.21	1.25	1.32	1.39	1.48	1.57	1.66
High Electricity Load Forecast Sensitivity	1.80	1.51	1.32	1.19	1.19	1.13	1.14	1.17	1.13	1.17	1.20	1.23	1.28	1.27	1.30	1.35	1.41	1.47	1.58	1.66

Incremental Increase/(Decrease) from Financial Forecast Scenario Capital Coverage Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**2.26**	**2.23**	**1.61**	**1.20**	**1.21**	**1.08**	**1.06**	**1.06**	**1.08**	**1.16**	**1.16**	**1.21**	**1.29**	**1.27**	**1.32**	**1.37**	**1.43**	**1.52**	**1.59**	**1.66**
Low Electricity Load Forecast Sensitivity	0.00	(0.00)	0.00	(0.04)	(0.07)	(0.04)	(0.03)	(0.01)	(0.03)	(0.02)	(0.02)	(0.02)	(0.02)	(0.01)	0.00	0.03	0.03	0.03	0.04	0.04
High Electricity Load Forecast Sensitivity	0.00	(0.00)	0.00	0.04	0.02	(0.00)	0.02	0.03	(0.00)	(0.02)	(0.01)	(0.01)	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)	(0.04)	(0.02)	(0.03)

Capital Coverage Ratio Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**2.26**	**2.23**	**1.61**	**1.20**	**1.21**	**1.08**	**1.06**	**1.06**	**1.08**	**1.16**	**1.16**	**1.21**	**1.29**	**1.27**	**1.32**	**1.37**	**1.43**	**1.52**	**1.59**	**1.66**
Low Electricity Load Forecast Sensitivity	2.26	2.23	1.61	1.16	1.15	1.05	1.04	1.05	1.05	1.14	1.14	1.19	1.27	1.26	1.32	1.40	1.47	1.55	1.62	1.70
High Electricity Load Forecast Sensitivity	2.26	2.23	1.61	1.24	1.24	1.08	1.08	1.09	1.08	1.15	1.15	1.20	1.27	1.25	1.30	1.36	1.42	1.48	1.56	1.63

REFERENCE:

Tab 8, Section 8.3, pg. 7
2017/18 GRA dated May 26, 2017, Tab 8, pg. 19, Figure 8.8
Tab 8, Appendix 8.1, Tables 1 & 2, pg. 4 and Table A1, pg. 18
Tab 3 (Amended), Dec 9, 2022, pg. 9

PREAMBLE TO IR (IF ANY):

MH states:

"Water Rental fees, a generation related expense, are lower than PCOSS21 due to the reduction in Water Rentals fees paid by Manitoba Hydro as announced by the Provincial Government on November 23, 2022." **(Tab 8, pg. 7)**

The significant increase in export revenue to $1.15 billion in the 2023/24 budget has resulted in a $525 million increase in Net Export Revenue ("NER") in PCOSS24 compared to PCOSS21." **(Tab 8, pg. 7)**

"Finance expense in PCOSS24 incorporates the 50% reduction in debt guarantee fees announced by the Provincial Government on November 23, 2022." **(Appendix 8.1, pg. 4)**

"Over the 20-year financial forecast scenario the direct savings from the reduction of the fees is estimated to total approximately $4 billion." **(Tab 3, pg. 9)**

MH provided Table 5 that reflects the RCC impacts of each methodology change in PCOSS24 compared to a scenario without the methodology changes but has not provided analysis to quantify the impacts of the cost changes between PCOSS18, PCOSS21 and PCOSS24, including the isolated impact of the reduction to PGF and Water Rental Fees.

QUESTION:

a) Please explain how Water Rental Fees are functionalized, classified and allocated and indicate (or otherwise explain) whether the methodology is consistent with PCOSS18 and PCOSS21.

b) Please provide a table that identifies total forecasted Water Rental Fees and the total directly or indirectly (through NER) allocated to each domestic customer class ($ and %) for each cost-of-service study PCOSS18, PCOSS21, PCOSS24, and PCOSS24 – 2024/25 Test Year.

c) Please explain how Finance expense is functionalized, classified, and allocated and indicate (or otherwise explain) whether the methodology is consistent with PCOSS18 and PCOSS21.

d) Please provide a table that identifies the total Finance expense allocated to each customer class ($ and %) for each cost-of-service study PCOSS18, PCOSS21, PCOSS24, and PCOSS24 – 2024/25 Test Year.

e) Please provide a qualitative discussion of whether the impact from the reduction in Water Rental Fees and the Provincial Guarantee Fee benefits certain customer classes to a greater degree, all else equal, or benefit all classes equally.

f) Please provide a scenario that identifies in dollars and on a percentage of net cost to serve basis (Table A1) that each customer class is expected to benefit from lower Water Rental Fees and the PGF over the 20-year financial forecast based on PCOSS24 (all else equal):

    i. Directly through lower fees

    ii. Indirectly on a secondary basis as a result of the disproportionate benefit that arises from cost allocation, whereby the lowering of generation and transmission costs benefits larger volume customer classes to a greater degree than lower volume customer classes such as Residentials.

    Please provide a summary table that separates the direct and indirect/secondary benefits by class over the 20-year period (in dollars and on a percentage basis). Provide all assumptions and caveats as necessary.

g) Please provide a PCOSS24 scenario for the 2023/24 Test Year that isolates the impact of the reduction in Water Rental Fees and includes both the dollar impact by customer class and the RCC impact by class. Please provide all supporting schedules including a version of Tables 1 & 2, the assumptions, a qualitative discussion of the results, and caveats as necessary.

h) Please provide a PCOSS24 scenario for the 2023/24 Test Year that isolates the impact of the reduction of the Provincial Guarantee Fee and includes both the dollar impact by customer class and the RCC impact by class. Please provide all supporting schedules, including Tables 1 & 2, the assumptions, a qualitative discussion of the results, and caveats as necessary.

RESPONSE:

a) Water rental fees are functionalized as Generation, classified as 100% Energy and allocated using the E12 Unweighted Energy allocator in PCOSS24. The methodology is consistent with PCOSS18 and PCOSS21.

b) Water rentals are allocated to customer classes using the E12 Unweighted Energy allocator. Water rentals are also indirectly allocated to customer classes through the practice of assigning a share of water rentals against export revenues and then using Net Export Revenue to offset the allocated Generation and Transmission costs for each class. The indirect amount for each class was calculated by allocating the export related water rentals in proportion to the share of NER allocated to each class. In PCOSS24 the water rentals allocated using E12 were $39.4 million, while the remaining $31.1 million was allocated indirectly via Net Export Revenue.

The following table shows the total water rental costs, both direct and indirect, for each customer class.

	PCOSS24 ($ Million)	PCOSS21 ($ Million)	PCOSS18 ($ Million)
Residential	28.0	44.8	41.1
GSS Non-Demand	6.7	9.4	8.5
GSS Demand	5.5	12.0	11.1
GSM	9.4	16.3	16.3
GSL 0-30KV	5.8	10.0	8.7
GSL 30-100KV	5.6	9.6	7.6
GSL >100KV	9.3	20.0	21.2
Area & Roadway Lighting	0.2	0.3	0.4
Total Water Rentals	70.5	122.4	114.7

The following table shows the share of total water rentals, both direct and indirect, for each customer class.

	PCOSS24 (% Share)	PCOSS21 (% Share)	PCOSS18 (% Share)
Residential	40%	37%	36%
GSS Non-Demand	9%	8%	7%
GSS Demand	8%	10%	10%
GSM	13%	13%	14%
GSL 0-30KV	8%	8%	8%
GSL 30-100KV	8%	8%	7%
GSL >100KV	13%	16%	18%
Area & Roadway Lighting	0%	0%	0%
Total Water Rentals	100%	100%	100%

Manitoba Hydro has not prepared a version of PCOSS24 based on the 2024/25 test year and therefore cannot provide the requested results for "PCOSS24 - 2024/25 Test Year". Please see Manitoba Hydro's response to COALITION/MH I-130a.

c) Finance expense is functionalized in proportion to Average Rate Base. Rate Base is calculated as gross investment (including forecast capital additions), less accumulated depreciation and customer contributions. Average Rate Base for fiscal years 2022/23 and 2023/24 is used to functionalize net finance expense as well as the contribution to reserves.

The following table provides the Classification and Allocation used for the finance expense after it has been functionalized.

Function	Classification	Allocation Table
Generation	60.7% Energy	E12 Unweighted Energy
	39.3% Demand	D14 CP Demand
Transmission	Demand	D13 CP Demand
Transmission - US Interconnections	60.7% Energy	E13 Unweighted Energy
	39.3% Demand	D13 CP Demand
Subtransmission	Demand	D21 CP Demand
Distribution - Stations, Pole & Wire, Transformers	Demand	D32/D36/D40 Class NCP Demand
Distribution – Services	Customer	C27 Weighted Customer
Distribution – Meters	Customer	C40 Weighted Customer

The methodology is consistent with PCOSS18 and PCOSS21.

d) The following table shows the Finance Expense (which includes Finance Income and Finance-related portion of Corporate Allocation) allocated to each class.

	PCOSS24 ($ Million)	PCOSS21 ($ Million)	PCOSS18 ($ Million)
Residential	403.0	389.1	245.1
GSS Non-Demand	89.5	74.5	45.6
GSS Demand	71.9	92.7	57.2
GSM	116.8	119.6	78.8
GSL 0-30KV	67.2	67.6	37.0
GSL 30-100KV	57.1	56.0	25.8
GSL >100KV	91.2	112.9	67.9
Area & Roadway Lighting	6.5	7.3	6.5
Diesel	0.6	0.6	0.4
Total Finance Expense	904.0	920.2	564.4

The following table shows the share of total Finance Expense allocated to each class.

	PCOSS24 (% Share)	PCOSS21 (% Share)	PCOSS18 (% Share)
Residential	45%	42%	43%
GSS Non-Demand	10%	8%	8%
GSS Demand	8%	10%	10%
GSM	13%	13%	14%
GSL 0-30KV	7%	7%	7%
GSL 30-100KV	6%	6%	5%
GSL >100KV	10%	12%	12%
Area & Roadway Lighting	1%	1%	1%
Diesel	0%	0%	0%
Total Finance Expense	100%	100%	100%

Manitoba Hydro has not prepared a version of PCOSS24 based on the 2024/25 test year and therefore cannot provide the requested results for "PCOSS24 - 2024/25 Test Year". Please see Manitoba Hydro's response to Coalition/MH I-130a.

e) The Provincial Guarantee Fee (PGF) is included as part of finance expense and is functionalized in proportion to Average Rate Base. In PCOSS24 this results in 83.4% of the PGF being functionalized as Generation and Transmission.

Water Rental fees are functionalized as 100% Generation.

Therefore, the reduction in water rental fees and the Provincial Guarantee Fee (PGF) will largely result in a decrease in G&T costs. Decreases in G&T costs will tend to increase the RCC for the General Service Large classes whose costs are almost exclusively Generation and Transmission. The reduction in G&T costs will tend to decrease the RCC for classes that are allocated the costs of all functions, and therefore receive relatively less Generation and Transmission costs.

f)

i. The reduction to water rentals and the PGF will reduce the revenue requirement by approximately $60 and $115 million, respectively, for each year in the 20-year finance forecast.

The revenue requirement in PCOSS24 is $3,020 million. An estimate of what the annual revenue requirement would have been without the reduction in these fees is determined by adding back these reductions to the PCOSS24 revenue requirement. This yields a revised revenue requirement of $3,196 million. The reduction is 5.5% of this revised revenue requirement and provides an estimate of the overall direct annual benefit to all classes due to the reduction in fees.

ii. The impact due to a change in costs is typically modelled in the PCOSS by including an offsetting change to net income. This adjustment ensures that the total revenue requirement continues to match total revenues, and the overall RCC in the PCOSS remains at unity. This adjustment is appropriate in the test year where all other costs are static but is not a reasonable approach to use to model the effects of cost changes over the longer-term. To estimate the differential impact due to the fee reduction over the 20-year financial forecast Manitoba Hydro has assumed equal changes in all costs within the revenue requirement so that total costs continue to match total revenue.

Since PCOSS24 already reflects the lower fees the PCOSS24 revenue requirement was first modified by increasing finance expense by $115 million, the domestic share of water rentals by $34 million and the export share of water rentals by $26 million. All cost components of this modified revenue requirement were then reduced by 5.5% so that the total revenue requirement once again matched the total revenue included in PCOSS24.

The change in RCC compared to the unmodified PCOSS24 represents the impact of an increase in fees, so the estimated differential benefit by class is the inverse of the RCC change. The combined benefit is estimated by adding the differential benefit to the overall 5.5% reduction in revenue requirement due to the lower fees.

The following table shows that reduction in fees provides a significant benefit to all customer classes; however, since the reduction in fees is largely associated with the Generation and Transmission function the reduction will benefit some classes more than others.

	(1) PCOSS24 RCC	(2) PCOSS24 RCC With Increased Fee	(3) (2-1) RCC Change due to Increased Fee	(4) (-3) Differential Benefit due to Reduced Fee	(5) Overall Direct Benefit due to Reduced Fee	(6) (4+5) Combined Benefit due to Reduced Fee
Residential	94.4%	94.8%	0.4%	-0.4%	5.5%	5.1%
GSS Non-Demand	109.7%	109.9%	0.2%	-0.2%	5.5%	5.3%
GSS Demand	101.8%	101.8%	0.0%	0.0%	5.5%	5.5%
GSM	100.3%	100.1%	-0.2%	0.2%	5.5%	5.7%
GSL 0-30kV	97.9%	97.4%	-0.5%	0.5%	5.5%	6.0%
GSL 30-100kV	112.4%	110.7%	-1.7%	1.7%	5.5%	7.2%
GSL >100kV	113.2%	111.2%	-2.0%	2.0%	5.5%	7.5%
A&RL	108.2%	110.9%	2.7%	-2.7%	5.5%	2.8%

g) Since PCOSS24 already reflects the lower water rental fees the impact of the reduction has been estimated by increasing water rental fees to the level prior to the announcement by the Provincial Government on November 23, 2022.

The assumed increase in water rental fees results in a decrease in the net income included in the 2023/24 revenue requirement used in the scenario.

The reduction in net income is functionalized using Average Rate Base and will still largely be functionalized as Generation and Transmission related, which will offset a significant portion of the additional water rental costs for each class. However, the additional water rentals still result in an overall increase in the G&T share of revenue requirement which will tend to decrease the RCC of General Service Large classes and increase the RCC for distribution level classes.

Since the scenario illustrates the impact of an increase in water rental fees, the benefit due to November 23, 2022 reduction will be the inverse of the change in RCCs. The reduction in water rentals will tend to increase the RCC of General Service Large classes and decrease the RCC for distribution level classes.

The following versions of Table 1 and Table 2 reflect the revised rate base investment and revenue requirement including the assumed increase in water rental fees. Water rentals are not a component of rate base investment so there is no change between versions in Table 1.

Table 1 - Comparison of Functionalized Rate Base Investment

	Average Rate Base ($ millions)		Percentage Share of Rate Base	
	PCOSS24	COALITION/MH I-138g	PCOSS24	COALITION/MH I-138g
Generation	20,113	20,113	74.8%	74.8%
Transmission	2,329	2,329	8.7%	8.7%
Subtransmission	790	790	2.9%	2.9%
Distribution Plant	3,397	3,397	12.6%	12.6%
Distribution Services	136	136	0.5%	0.5%
A&RL	117	117	0.4%	0.4%
Diesel	18	18	0.1%	0.1%

Table 2 - Comparison of Functionalized Revenue Requirement

	Revenue Requirement ($ millions)		Percentage Share of Revenue Requirement	
	PCOSS24	COALITION/MH I-138g	PCOSS24	COALITION/MH I-138g
Generation	1,038	1,050	55.6%	56.3%
Transmission	151	151	8.1%	8.1%
Subtransmission	90	88	4.8%	4.7%
Distribution Plant	430	421	23.0%	22.6%
Distribution Services	119	119	6.4%	6.4%
A&RL	25	24	1.3%	1.3%
Diesel	13	13	0.7%	0.7%

The following versions of Schedules A1 - A3, Table F1 and Schedules C1-C4 reflect the assumed increase in water rental fees.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2024
Revenue Cost Coverage Analysis
Coalition I-138g
SUMMARY

Customer Class	Total Cost ($ million)	Class Revenue ($ million)	RCC % Prior to NER	Net Export Revenue ($ million)	Net Cost ($ million)	RCC % Current Rates
Residential	1,336.3	831.6	62.2%	457.8	878.5	94.7%
General Service - Small Non Demand	295.6	210.3	71.2%	104.1	191.5	109.8%
General Service - Small Demand	232.6	150.7	64.8%	84.7	147.9	101.9%
General Service - Medium	375.5	235.6	62.7%	140.4	235.1	100.2%
General Service - Large 0 - 30kV	213.2	125.0	58.6%	85.1	128.1	97.6%
General Service - Large 30-100kV	176.7	107.0	60.6%	80.4	96.2	111.2%
General Service - Large >100kV	280.9	166.6	59.3%	131.9	149.0	111.8%
SEP	2.8	3.0	106.3%	-	2.8	106.3%
Area & Roadway Lighting	27.3	26.7	97.9%	2.9	24.4	109.5%
Total General Consumers	2,940.8	1,856.6	63.1%	1,087.2	1,853.5	100.2%
Diesel	12.9	9.9	76.7%	-	12.9	76.7%
Export	66.9	1,154.1	1724.2%	(1,087.2)	1,154.1	100.0%
Total System	3,020.6	3,020.6	100.0%	-	3,020.6	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2024
Customer, Demand, Energy Cost Analysis
Coalition I-138g
SUMMARY

	CUSTOMER			DEMAND				ENERGY			
Class	Cost ($ million)	Number of Customers	Unit Cost $/Month	Cost ($ million)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($ million)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	84.2	542,274	12.94	535.0	0%	n/a	n/a	259.3	8,097,085	9.81	**
General Service - Small Non Demand	17.3	61,463	23.49	109.4	0%	n/a	n/a	64.8	2,038,401	8.55	**
General Service - Small Demand	9.8	8,240	98.94	84.0	48%	2,512	16.02	54.1	1,711,545	5.72	
General Service - Medium	10.9	2,203	413.05	131.0	86%	6,840	16.45	93.2	2,957,104	3.78	
General Service - Large <30kV	3.8	378	n/a	65.7	100%	4,548	15.27 *	58.6	1,876,381	3.12	
General Service - Large 30-100kV	1.9	48	n/a	36.1	100%	3,736	10.16 *	58.3	1,932,349	3.02	
General Service - Large >100kV	2.7	21	n/a	49.7	100%	5,786	9.07 *	96.6	3,249,357	2.97	
SEP	0.1	31	382.15	0.3	0%	n/a	n/a	2.4	48,033	5.58	**
Area & Roadway Lighting	19.3	170,764	9.43	3.1	0%	n/a	n/a	2.0	60,972	8.30	**
Total General Consumers	150.1	785,422		1,014.3		23,422		689.1	21,971,226		
Diesel	0.7	865	70.84	-	0%	n/a	n/a	12.2	17,972	67.91	**
Export	n/a	n/a	n/a	-	0%	n/a	n/a	66.9	14,728,000	0.45	***
Total System	150.8	786,287		1,014.3		23,422		768.3	36,717,199		

*includes recovery of Customer costs
**includes recovery of Demand costs
***includes recovery of Customer and Demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2024
Functional Breakdown
Coalition I-138g
S U M M A R Y

Class	Total Cost ($ million)	Generation Cost ($ million)	%	Transmission Cost ($ million)	%	Subtransmission Cost ($ million)	%	Distribution Cust Service ($ million)	%	Distribution Plant Cost ($ million)	%
Residential	878.5	435.4	49.6%	70.7	8.0%	46.9	5.3%	79.3	9.0%	246.2	28.0%
General Service - Small Non Demand	191.5	100.3	52.4%	14.6	7.6%	9.5	5.0%	15.8	8.2%	51.3	26.8%
General Service - Small Demand	147.9	81.9	55.4%	11.5	7.8%	7.5	5.1%	7.0	4.7%	40.0	27.0%
General Service - Medium	235.1	136.7	58.1%	18.1	7.7%	11.7	5.0%	9.8	4.1%	58.8	25.0%
General Service - Large <30kV	128.1	83.4	65.1%	10.4	8.2%	6.7	5.2%	3.1	2.4%	24.5	19.1%
General Service - Large 30-100kV	96.2	79.5	82.6%	9.1	9.5%	5.8	6.0%	1.6	1.7%	0.3	0.3%
General Service - Large >100kV	149.0	130.5	87.6%	15.8	10.6%	-	0.0%	2.5	1.6%	0.3	0.2%
SEP	2.8	2.4	83.9%	0.3	11.1%	-	0.0%	0.1	4.3%	0.0	0.7%
	-										
Area & Roadway Lighting	24.4	2.8	11.6%	0.4	1.5%	0.2	1.0%	1.1	4.4%	19.9	81.5%
Total General Consumers	1,853.5	1,052.9	56.8%	151.0	8.1%	88.3	4.8%	120.1	6.5%	441.3	23.8%
Diesel	12.9	12.2	94.3%	-	0.0%	-	0.0%	-	0.0%	0.7	5.7%
Export	66.9	66.9	100.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total System	1,933.4	1,132.0	58.5%	151.0	7.8%	88.3	4.6%	120.1	6.2%	442.0	22.9%

Prospective Cost Of Service Study
March 31, 2024
Classified Costs by Allocation Table
($ millions)
Coalition I-138g
System Load Factor: 60.7%

Allocation Table	Function		Interest	Depreciation	Operating	Common Costs	Total
E12	Generation	Energy Share	625.3	232.3	345.0	91.0	1,293.6
D14	Generation	Demand Share	404.9	150.4	120.0	44.0	719.3
	Common Costs		26.1	36.1	72.8	(135.0)	-
	Total Generation		1,056.3	418.8	537.8	-	2,012.9
E13	Transmission	Energy Share	12.1	3.1	5.4	1.7	22.3
E13	Transmission		-	-	-		-
D13	Transmission	Demand Share	97.2	41.0	39.5	61.1	238.7
D13	Transmission		-	-	-		-
D13	Transmission Non-Tariffable	Demand Share	3.7	1.7	3.1	4.8	13.3
	Common Costs		8.7	10.5	48.4	(67.6)	-
	Total Transmission		121.6	56.3	96.5	-	274.4
D21	Subtrans		39.5	18.9	20.1	9.7	88.3
	Common Costs		2.1	2.8	4.8	(9.7)	-
	Total Subtransmission		41.7	21.7	24.9	-	88.3
D32	Dist. Plant	Stations	46.8	27.3	33.1	17.6	124.8
D36	Dist. Plant	Lines	94.4	43.8	69.1	36.8	244.2
D40	Dist. Plant	S/E	21.3	12.7	5.5	2.9	42.4
C27	Dist. Plant	Services	1.2	0.5	0.9	0.5	3.0
C40	Dist. Plant	Meters	3.1	5.5	0.1	0.0	8.7
	Common Costs		12.1	15.6	30.1	(57.8)	-
	Total Distribution Plant		178.9	105.4	138.8	-	423.1
C11	Dist Serv	Cust Acct - Billings	-	-	20.4	4.3	24.7
C12	Dist Serv	Cust Acct - Collections	-	-	14.9	3.1	18.1
C14	Dist Serv	Inspection	-	-	4.4	0.9	5.4
C15	Dist Serv	Meter Read	-	-	7.5	1.6	9.1
C10	Dist Serv	General	-	1.0	4.1	0.9	6.0
C13	Dist Serv	General - Smaller Customers	-	-	31.5	6.7	38.1
C16	Dist Serv	General - Excl GSL >30kV	-	-	11.8	2.5	14.2
C23	Dist Serv	Industrial & Commercial	-	-	3.8	0.8	4.6
	Common Costs		7.2	9.7	3.9	(20.8)	-
	Total Distribution Services		7.2	10.7	102.2	-	120.1
	Total Allocated Costs		1,405.6	612.9	900.2	-	2,918.7
E01	Generation	Diesel	0.4	0.8	10.1	1.0	12.2
C01	Distribution	Diesel	0.1	0.1	0.5	0.1	0.7
	Common Costs		0.5	0.4	0.1	(1.0)	-
C01	Distribution	Lighting	5.9	4.4	6.7	1.2	18.2
	Common Costs		0.3	0.7	0.3	(1.2)	-
D04	Transmission	Taps - GSL >100kV	0.8	0.3	-		1.1
E01	Generation	Export	-	-	66.9		66.9
D04	Transmission	Export					-
E01	Generation	SEP - GSM	1.1	0.5	0.7		2.3
D04	Transmission	SEP - GSM	0.1	0.1	0.1		0.3
E01	Generation	SEP - GSL 0-30kV	0.1	0.0	0.0		0.1
D04	Transmission	SEP - GSL 0-30kV	0.0	0.0	0.0		0.0
	Total Directs		9.3	7.2	85.4	-	101.9
	Total		1,414.9	620.1	985.6	-	3,020.6
	Energy		639.0	236.7	428.1	93.7	1,397.5
	Demand		708.8	296.0	290.6	177.0	1,472.3
	Customer		10.2	11.5	106.5	22.5	150.8
			1,358.0	544.2	825.2	293.2	3,020.6

2024 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2024
($ MILLIONS)
Coalition I-138g

Asset Class	Average Rate Base Investment	Generation	Transmission	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ASSIGNMENT Diesel	DIRECT ASSIGNMENT Lighting
GENERATION	14,882.0	14,882.0							
-Thermal	113.3	113.3							
DIESEL	7.2							7.2	
SUBSTATION	2,439.2	56.9	1,013.2	414.4	881.8		72.8		
- HVDC	2,546.2	2,546.2							
TRANSMISSION	911.1	309.7	601.4						
- HVDC	1,629.9	1,629.9							
- Dedicated Radial Taps	15.7		15.7						
- US Interconnections	378.4		378.4						
- Non-Tariffable Transmission	70.8		70.8						
DISTRIBUTION	2,323.3				2,209.8			1.8	111.8
SUBTRANSMISSION	331.3			331.3					
TRANSFORMERS									
- SUBSTATION	78.5	55.4	10.1	4.1	8.8				
- DISTRIBUTION	8.7				8.7				
METERS	58.5				58.5				
BUILDINGS	380.7	176.9	46.1	13.2	73.3	64.4		4.4	2.5
COMMUNICATION	235.9	134.9	35.1	10.1	55.9	-		-	-
SYSTEM CONTROL	66.6	10.7	-	2.7	18.7	-	34.6	-	-
GENERAL EQUIPMENT	424.0	197.0	51.3	14.7	81.7	71.7		4.9	2.7
SUBTOTAL	26,901.3	20,112.9	2,222.0	790.5	3,397.1	136.2	107.4	18.2	117.0
MOTOR VEHICLES	154.3								
TOTAL	27,055.7	20,112.9	2,222.0	790.5	3,397.1	136.2	107.4	18.2	117.0

2024 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE FOR CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2024
($ MILLIONS)
Coalition I-138g

Asset Class	Ending Rate Base Investment	Generation	Transmission	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ASSIGNMENT Diesel	DIRECT ASSIGNMENT Lighting
GENERATION	14,859.3	14,859.3							
-Thermal	109.7	109.7							
DIESEL	7.6							7.6	
SUBSTATION	2,458.2	56.2	1,024.8	424.0	876.7		76.5		
- HVDC	2,517.6	2,517.6							
TRANSMISSION	912.1	308.0	604.1						
- HVDC	1,621.7	1,621.7							
- Dedicated Radial Taps	15.5		15.5						
- US Interconnections	376.3		376.3						
- Non-Tariffable Transmission	70.1		70.1						
DISTRIBUTION	2,368.4				2,252.7			1.8	114.0
SUBTRANSMISSION	340.3			340.3					
TRANSFORMERS									
- SUBSTATION	78.5	55.4	10.1	4.2	8.7				
- DISTRIBUTION	8.7				8.7				
METERS	61.1				61.1				
BUILDINGS	372.2	172.9	45.0	12.9	71.7	63.0		4.3	2.4
COMMUNICATION	228.3	130.5	34.0	9.7	54.1	-		-	-
SYSTEM CONTROL	66.4	10.6	-	2.7	18.6	-	34.5	-	-
GENERAL EQUIPMENT	454.4	211.1	55.0	15.7	87.5	76.9		5.2	2.9
SUBTOTAL	26,926.3	20,053.1	2,234.9	809.4	3,439.7	139.9	111.0	18.9	119.3
MOTOR VEHICLES	146.3								
TOTAL	27,072.6	20,053.1	2,234.9	809.4	3,439.7	139.9	111.0	18.9	119.3

2024 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTEREST EXPENSE & RESERVE CONTRIBUTION
FORECAST YEAR ENDING MARCH 31, 2024
($ MILLIONS)
Coalition I-138g

Asset Class	Interest & Reserve Expense	Generation	Transmission	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ASSIGNMENT Diesel	DIRECT ASSIGNMENT Lighting
GENERATION	714.1	714.1	-	-	-	-	-	-	-
-THERMAL	5.4	5.4	-	-	-	-	-	-	-
DIESEL	0.3	-	-	-	-	-	-	0.3	-
SUBSTATION	117.0	2.7	48.6	19.9	42.3	-	3.5	-	-
- HVDC	122.2	122.2	-	-	-	-	-	-	-
TRANSMISSION	43.7	14.9	28.9	-	-	-	-	-	-
- HVDC	78.2	78.2	-	-	-	-	-	-	-
- Dedicated Radial Tabs	0.8	-	0.8	-	-	-	-	-	-
- US Interconnections	18.2	-	18.2	-	-	-	-	-	-
- Non-Tariffable Transmission	3.4	-	3.4	-	-	-	-	-	-
DISTRIBUTION	111.5	-	-	-	106.0	-	-	0.1	5.4
SUBTRANSMISSION	15.9	-	-	15.9	-	-	-	-	-
TRANSFORMERS									
- SUBSTATION	3.8	2.7	0.5	0.2	0.4	-	-	-	-
- DISTRIBUTION	0.4	-	-	-	0.4	-	-	-	-
METERS	2.8	-	-	-	2.8	-	-	-	-
BUILDINGS	18.3	8.5	2.2	0.6	3.5	3.1	-	0.2	0.1
COMMUNICATION	11.3	6.5	1.7	0.5	2.7	-	-	-	-
SYSTEM CONTROL	3.2	0.5	-	0.1	0.9	-	1.7	-	-
GENERAL EQUIPMENT	20.3	9.5	2.5	0.7	3.9	3.4	-	0.2	0.1
SUBTOTAL	1,290.9	965.1	106.6	37.9	163.0	6.5	5.2	0.9	5.6
MOTOR VEHICLES									
TOTAL	1,290.9	965.1	106.6	37.9	163.0	6.5	5.2	0.9	5.6

2024 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2024

Coalition I-138g

Asset Class	Capital Tax	Generation	Transmission	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ASSIGNMENT Diesel	DIRECT ASSIGNMENT Lighting
GENERATION	68.5	68.5	-	-	-	-	-	-	-
-THERMAL	0.5	0.5	-	-	-	-	-	-	-
DIESEL	0.0	-	-	-	-	-	-	0.0	-
SUBSTATION	11.3	0.3	4.7	2.0	4.0	-	0.4	-	-
- HVDC	11.6	11.6	-	-	-	-	-	-	-
TRANSMISSION	4.2	1.4	2.8	-	-	-	-	-	-
- HVDC	7.5	7.5	-	-	-	-	-	-	-
- Dedicated Radial Tabs	0.1	-	0.1	-	-	-	-	-	-
- US Interconnections	1.7	-	1.7	-	-	-	-	-	-
- Non-Tariffable Transmission	0.3	-	0.3	-	-	-	-	-	-
DISTRIBUTION	10.9	-	-	-	10.4	-	-	0.0	0.5
SUBTRANSMISSION	1.6	-	-	1.6	-	-	-	-	-
TRANSFORMERS									
- SUBSTATION	0.4	0.3	0.0	0.0	0.0	-	-	-	-
- DISTRIBUTION	0.0	-	-	-	0.0	-	-	-	-
METERS	0.3	-	-	-	0.3	-	-	-	-
BUILDINGS	1.7	0.8	0.2	0.1	0.3	0.3	-	0.0	0.0
COMMUNICATION	1.1	0.6	0.2	0.0	0.2	-	-	-	-
SYSTEM CONTROL	0.3	0.0	-	0.0	0.1	-	0.2	-	-
GENERAL EQUIPMENT	2.1	1.0	0.3	0.1	0.4	0.4	-	0.0	0.0
SUBTOTAL	124.1	92.4	10.3	3.7	15.8	0.6	0.5	0.1	0.5
MOTOR VEHICLES									
TOTAL	124.1	92.4	10.3	3.7	15.8	0.6	0.5	0.1	0.5

h) Since PCOSS24 already reflects the lower Provincial Guarantee Fee (PGF) the RCC impact is estimated by increasing finance expense to include the higher PGF costs consistent with the level prior to the announcement by the Provincial Government on November 23, 2022.

The assumed increase in PGF costs results in a corresponding decrease in net income in the 2023/24 revenue requirement used in the scenario.

Finance expense and net income are added together and treated as a single input into the PCOSS. They are functionalized, classified, and allocated on exactly the same basis so the changes in costs will offset each other and there are no changes to PCOSS24 due to the change in PGF.

Last Five Years of Studies
Alliance Consulting Group
1/20/2023

Asset Location	Commission	Docket (If Applicable	Company	Year	Description	Accounting Standards
Florida	Florida Public Service Commission	20220219	People Gas System	2022	Gas Depreciation Study	US GAAP Standards
Michigan	Michigan Public Service Commission	U-21329	Michigan Gas Utilities Corporation	2022	Gas Depreciation Study	US GAAP Standards
Dominica	Independent Regulatory Commission		Dominica Electricity Services LTD	2022	Electric Depreciation Study	IFRS Standards
New Mexico	New Mexico Public Regulation Commission	22-00270-UT	Public Service of New Mexico	2022	Electric Depreciation Study	US GAAP Standards
New Mexico	New Mexico Public Regulation Commission	22-00286-UT	Southwestern Public Service Company	2022	Electric Technical Update	US GAAP Standards
Minnesota	Minnesota Public Utilities Commission	22-299	Northern States Power-Minnesota	2022	Electric Gas and Common Depreciation Study	US GAAP Standards
California	California Public Utilities Commission	A.22-08-010	Bear Valley Electric	2022	Electric Depreciation Study	US GAAP Standards
Michigan	Michigan Public Service Commission	U-21294	SEMCO Gas	2022	Gas Depreciation Study	US GAAP Standards
Arkansas	Arkansas Public Service Commission	22-064-U	Liberty Pine Bluff Water	2022	Water Depreciation Study	US GAAP Standards
Colorado	Colorado Public Utilities Commission	22AL-0348G	Atmos Energy	2022	Gas Depreciation Study	US GAAP Standards
New York	FERC	ER22-2581-000	New York Power Authority	2022	Transmission and General Depreciation Study	US GAAP Standards
South Carolina	South Carolina Public Service Commission	2022-89-G	Piedmont Natural Gas	2022	Natural Gas Depreciation Study	US GAAP Standards
California	California Public Utilities Commission	A.22-007-001	California American Water	2022	Water and Waste Water Depreciation Study	US GAAP Standards
Alaska	Regulatory Commission of Alaska	U-22-034	Chugach Electric Association	2022	Electric Depreciation Study	US GAAP Standards
Georgia	Georgia Public Service Commission	44280	Georgia Power Company	2022	Electric Depreciation Study	US GAAP Standards
California	California Public Utilities Commission	22-005-xxx	San Diego Gas and Electric	2022	Electric Gas and Common Depreciation Study	US GAAP Standards
California	California Public Utilities Commission	22-005-xxx	Southern California Gas	2022	Gas Depreciation Study	US GAAP Standards
Colorado	Colorado Public Utilities Commission	22AL-0046G	Public Service of Colorado	2022	Gas Depreciation given potential for climate change	US GAAP Standards
Texas	Public Utility Commission of Texas	53601	Oncor Electric Delivery	2022	Electric Depreciation Study	US GAAP Standards
New Jersey	New Jersey Board of Public Utilities	GR2222040253	South Jersey Gas	2022	Gas Depreciation Study	US GAAP Standards
Oklahoma	Corporation Commission of Oklahoma	PUD 202100163	Empire District Electric Company	2022	Electric Depreciation Study	US GAAP Standards
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study	US GAAP Standards
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study	US GAAP Standards

Last Five Years of Studies
Alliance Consulting Group
1/20/2023

Asset Location	Commission	Docket (If Applicable	Company	Year	Description	Accounting Standards
Ontario Canada	Ontario Energy Board	EB-2021-0110	Hydro One	2021	Electric Depreciation Study	US GAAP Standards
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study	US GAAP Standards
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study	US GAAP Standards
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study	US GAAP Standards
Wisconsin	Public Service Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study	US GAAP Standards
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study	US GAAP Standards
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study	US GAAP Standards
Wisconsin	Public Service Commission of Wisconsin	4220-DU-111	Northern States Power Wisconsin	2021	Transmission, Distribution General and Common Depreciation Study	US GAAP Standards
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Energy	2021	Statewide Gas Depreciation Study	US GAAP Standards
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study	US GAAP Standards
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study	US GAAP Standards
Texas	Texas Public Utility Commission	51802	Southwestern Public Service Company	2021	Electric Technical Update	US GAAP Standards
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study	US GAAP Standards
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update	US GAAP Standards
Yukon Territory Canada	Yukon Energy Board	2021 General Rate Application	Yukon Energy	2020	Electric Depreciation Study	IFRS Standards
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study	US GAAP Standards
Texas	Texas Public Utility Commission	51611	Sharyland Utilities	2020	Electric Depreciation Study	US GAAP Standards
Texas	Texas Public Utility Commission	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study	US GAAP Standards
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study	US GAAP Standards
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study	US GAAP Standards

Last Five Years of Studies
Alliance Consulting Group
1/20/2023

Asset Location	Commission	Docket (If Applicable	Company	Year	Description	Accounting Standards
Texas	Texas Public Utility Commission	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study	US GAAP Standards
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study	US GAAP Standards
Mexico	Comision Reguladora de Energia	G/352/TRA/2015 UH-250/125738/2019	Arguelles Depreciation Study	2020	Gas Depreciation Study	IFRS Standards
Tennessee	Tennessee Public Utility Commission	2000086	Piedmont Natural Gas	2020	Gas Depreciation Study	US GAAP Standards
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study	US GAAP Standards
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study	US GAAP Standards
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study	US GAAP Standards
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study	US GAAP Standards
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study	US GAAP Standards
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study	US GAAP Standards
Texas	Public Utility Commission of Texas	50734	Oncor Electric Delivery	2020	Life of Intangible Plant	US GAAP Standards
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study	US GAAP Standards
Kentucky	Kentucky Public Service Commission	2020-00064	Big Rivers	2020	Electric Depreciation Study	US GAAP Standards
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study	US GAAP Standards
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study	US GAAP Standards
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study	US GAAP Standards
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study	US GAAP Standards
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study	US GAAP Standards
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study	US GAAP Standards
New Mexico	New Mexico Public Regulation Commission		New Mexico Gas	2019	Gas Depreciation Study	US GAAP Standards
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study	US GAAP Standards
Texas	Railroad Commission of Texas	GUD 10900	Atmos Energy West Texas Division - Triangle	2019	Depreciation Rates for Natural Gas Property	US GAAP Standards
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study	US GAAP Standards

Last Five Years of Studies
Alliance Consulting Group
1/20/2023

Asset Location	Commission	Docket (If Applicable	Company	Year	Description	Accounting Standards
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Northern California	2019	Gas Depreciation Study	US GAAP Standards
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Southern California	2019	Gas Depreciation Study	US GAAP Standards
Texas	Railroad Commission of Texas	GUD 10895	CenterPoint Propane Air	2019	Depreciation Rates for Propane Air Assets	US GAAP Standards
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study	US GAAP Standards
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study	US GAAP Standards
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study	US GAAP Standards
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study	US GAAP Standards
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study	US GAAP Standards
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General	US GAAP Standards
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study	US GAAP Standards
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study	US GAAP Standards
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study	US GAAP Standards
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Compliance Filing	US GAAP Standards
Colorado	Colorado Public Utilities Commission	19AL-0063ST	Public Service of Colorado	2019	Steam Depreciation Study	US GAAP Standards
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study	US GAAP Standards
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study	US GAAP Standards
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study	US GAAP Standards
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study	US GAAP Standards
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study	US GAAP Standards
Texas	Public Utility Commission of Texas	48500	Golden Spread Electric Coop	2018	Electric Depreciation Study	US GAAP Standards
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study	US GAAP Standards
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study	US GAAP Standards
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study	US GAAP Standards
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study	US GAAP Standards

Last Five Years of Studies
Alliance Consulting Group
1/20/2023

Asset Location	Commission	Docket (If Applicable	Company	Year	Description	Accounting Standards
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates	US GAAP Standards
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study	US GAAP Standards
Louisiana	Louisiana Public Service Commission	U-34803	Atmos LGS	2018	Gas Depreciation Study	US GAAP Standards
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study	US GAAP Standards
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Depreciation Rate	US GAAP Standards
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates	US GAAP Standards
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study	US GAAP Standards
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study	US GAAP Standards

REFERENCE:

Appendix 5.1v pp. 38 of 77, Appendix 5.6, Tab 9 pp. 18-21 of 28

PREAMBLE TO IR (IF ANY):

Appendix 5.1 (p. 38): "*[Behind the Meter] BTM Solar PV energy produced in Manitoba results in a decrease in electric load consumption with the larger reduction occurring in the summer, when maximum solar production is achieved. In situations where customer's demand is less than what is produced, the energy produced is pushed back to the integrated system and sold to Manitoba Hydro. Manitoba Hydro assumes 25% of the energy generated by Solar PV installations will be sold back to the grid and not reduce domestic energy consumption. Manitoba's current peak demand occurs on a cold winter day, early in the morning or early evening, at times where solar resources are not available and as such, there are no impacts to Gross Total Peak Demand.*"

Appendix 5.6 presents the 2022 Supply/Demand Scenario. This scenario includes existing non-utility generation as base supply power resources contributing to winter peak capacity and dependable energy resources throughout the 2022/23 to 2041/42 planning period.
Tab 9 (p. 20-21): "*Energy produced, in excess to a customer's own needs, is purchased by Manitoba Hydro at the Excess Energy Price. […] The Excess Energy Price at the time of filing is $0.05079/kWh and is updated annually on April 1.*"

Tab 9 (p. 18) "*A total of 34.6 MW AC of solar panels were installed as part of the two-year Solar Energy Pilot program that was launched in April of 2016.*"

Tab 9 (p. 21): "*On August 8 2022, Efficiency Manitoba announced a new Solar Rebate Program. In addition, the federal government also offers rebates for installing solar PV through their Canada Greener Homes Grant.*"

QUESTION:

a) Please quantify the proportions of Behind the Meter (BTM) Solar PV energy that are incorporated in the "non-utility generation supply resources" each year as shown in Appendix 5.6.
b) Please tabulate the expected excess energy that Manitoba Hydro expects to receive from solar PV and other BTM generation each year throughout the electric load scenario.
c) Provide the derivation of the $0.05079/kWh excess energy purchase price. Is this price related to Manitoba Hydro's marginal value of generation?
d) In a similar format as the response to PUB/MH II-57 from the 2017/18 & 2018/19 GRA, please provide the updated generation and combined marginal values. Please identify which year's Energy Price Forecast underpins the marginal values.
e) Please explain whether future growth in BTM Solar PV energy sold back to Manitoba Hydro as a result of Efficiency Manitoba's new Solar Rebate Program will be treated as Behind the Meter Generation or DSM Savings in future Manitoba Hydro electric load forecasts.

RESPONSE:

a) Appendix 5.6, line item "Existing Non-Utility Generation" does not include any Behind the Meter ("BTM") Solar PV energy. Rather, Appendix 5.6, line item "Existing Non-Utility Generation" represents power purchases from non-utility generators in Manitoba, which include wind generation and solar photovoltaic ("PV") generation. Energy from these generators is considered "all to grid" (i.e., in front of the meter). The total installed nameplate capacity from all power purchases from Manitoba generators (non-utility generation) is approximately 260 MW. The energy quantities shown in Appendix 5.6, line item "Existing Non-Utility Generation" are aggregated between all non-utility generators in Manitoba, as individual energy output per generator is confidential information.

   All BTM Solar PV energy is included as part of the 2021 Electric Load Forecast Scenario net of DSM.

b) Manitoba Hydro has a projection of new BTM Solar PV embedded in the 2021 Electric Load Forecast Scenario. For all new installations, Manitoba Hydro assumes 25% of the energy generated by BTM Solar PV installations will be sold back to the grid. The following table shows the excess energy that Manitoba Hydro expects to receive from the projection of new BTM Solar PV each year throughout the 2021 Electric Load Forecast scenario.

Fiscal Year	Solar to Grid GWh
2022/23	1
2023/24	1
2024/25	2
2025/26	3
2026/27	4
2027/28	4
2028/29	6
2029/30	7
2030/31	9
2031/32	11
2032/33	13
2033/34	16
2034/35	20
2035/36	24
2036/37	29
2037/38	35
2038/39	42
2039/40	50
2040/41	60

c) The excess energy purchase price is currently calculated on an annual basis to reflect the market value of the energy. The price of $0.05079/kWh was derived from the average Day Ahead and Real Time on-peak price determined at the MHEB Midcontinent Independent Service Operator ("MISO") pricing node for the 2021 calendar year in US dollars. It was then converted to Canadian dollars using the Bank of Canada CAD/USD exchange rate for 2021 calendar year. The price can vary significantly depending on the market value. The table below contains historical excess energy prices over the last 5 years.

Historical Excess Energy Prices

Effective Date	Excess energy price ($/kWh)
2022 April 1	$0.05079
2021 April 1	$0.02403
2020 April 1	$0.02949
2019 April 1	$0.03949
2018 April 1	$0.03253

No, the excess energy price is not directly comparable/related to Manitoba Hydro's marginal value of generation. The excess energy price is an energy only value based on recent market price history. The marginal value of supply includes an energy value plus capacity values for generation, transmission and distribution and is based on future price and cost projections.

d) The updated 30 year levelized marginal and the annual marginal values based on general rate application assumptions are provided below. The 2022 spring energy price forecast was used for this analysis.

30 Year Levelized Marginal Values (Cents/kWh, CAD)		
Dollar Year	2021$	2022$
Generation	4.85	4.94
Transmission	0.29	0.30
Distribution	0.54	0.55
Total	5.69	5.80

5a

Basic Marginal Costs Applicable to Distribution Level Programs
Marginal Costs Given at Distribution
(Constant Year 2022 Canadian Dollars)

Notes: Marginal costs based on a uniform supply with a 100% capacity factor
Marginal costs referred to distribution (loss factor of 4.82% to translate back to High Voltage Level)
US/Cdn Exchange Rates and Escalation Factors (P911 January 11, 2022)
Updated transmission (2019) & distribution (2019) marginal costs

Fiscal Year	SUMMER		WINTER					ALL-IN		
	Generation Energy	Generation Capacity	Generation Energy	Generation Capacity	Transmission Capacity	Distribution Capacity	Total Capacity	SUMMER	WINTER	ANNUAL
	$/MWh	$/kW/Yr	$/MWh	$/kW/Yr	$/kW/Yr	$/kW/Yr	$/kW/Yr	$/MWh	$/MWh	$/MWh
2024/25	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2035/36	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2036/37	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2037/38	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2038/39	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2039/40	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2040/41	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2041/42	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2042/43	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2043/44	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2044/45	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2045/46	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2046/47	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2047/48	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2048/49	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2049/50	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2050/51	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2051/52	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2052/53	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2053/54	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Cost at 3.70% Discount Rate	[redacted]	[redacted]	[redacted]	[redacted]	**26.33**	**48.38**	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]						Levelized Value (Cents/kWh)			5.8

e) Manitoba Hydro will continue to collaborate with Efficiency Manitoba to ensure any DSM activity related to BTM Generation (Solar and/or by other means) will not be double counted in the modelling within future Electric Load Forecasts.

REFERENCE:

Appendix 9.9

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the engagement letter/contract for the completion of the ASL study.
b) Please provide the CV of the author of the Alliance Study.
c) Please provide a list of IFRS compliant studies that have been prepared by the author and identify the number that are based on ASL basis.

RESPONSE:

a) Attachment 1 contains the Terms of Reference for IFRS-compliant ASL depreciation.

b) Attachment 2 contains the resume and biography for Dane A. Watson, PE, MBA, CDP and Managing Partner of Alliance Consulting Group, LP. Dane Watson completed the IFRS-compliant ASL Study.

c) Alliance has completed the following depreciation studies in the last 5 years for clients that prepare financial statements following IFRS Accounting Standards, all of which used the Average life group, remaining life depreciation methodology:

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description	Accounting Standards
Dominica	Independent Regulatory Commission		Dominica Electricity Services LTD	2022	Electric Depreciation Study	IFRS Standards
Yukon Territory Canada	Yukon Energy Board	2021 General Rate Application	Yukon Energy	2020	Electric Depreciation Study	IFRS Standards
Mexico	Comision Reguladora de Energia	G/325/TRA/2015 UH-250/125738/2019	Arguelles Depreciation Study	2020	Gas Depreciation Study	IFRS Standards

MFR 51 (Revised)

Prior references
PUB MFR 35, 2017/18 & 2018/19 GRA

Operating Expenses

Schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized for each of the years 2016/17 through the test years. This analysis should include the total labour and benefits capitalized for each year, total labour and benefits and the percentage of labour and benefits capitalized.

Please see Figure 1 below which provides information for 2016/17 through the test years. Note that domestic revenue excludes the impacts of the interim and proposed rate increases.

Figure 1 Capitalized Wages & Salaries, Overtime and Employee Benefits

MANITOBA HYDRO
CAPITALIZED WAGES & SALARIES, OVERTIME, EMPLOYEE BENEFITS
(in thousands of $)

	2016/17 Actual	2017/18 Actual	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Actual	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
Total O&A, before Capitalization	$946,975	$916,369	$858,876	$856,773	$863,250	$888,660	$906,909	$990,538	$1,034,683
Domestic Revenue	1,418,778	1,464,394	1,706,984	1,702,135	1,714,455	$1,813,817	1,809,803	1,783,225	1,789,097
Wages, Salaries, Overtime & Benefits Capitalized	292,620	286,258	241,818	238,426	221,232	196,681	203,317	205,753	214,751
Wages, Salaries, Overtime & Benefits Charged to Operations	462,872	439,413	424,261	418,982	454,120	469,547	470,653	500,372	522,513
Total Wages & Salaries, Overtime & Benefits	$755,492	$725,670	$666,079	$657,407	$675,352	$666,228	$673,970	$706,125	$737,264
Percentage Calculations:									
Percentage of Total Wages & Salaries, Overtime & Benefits									
Capitalized - Wages & Salaries, Overtime & Benefits	39%	39%	36%	36%	33%	30%	30%	29%	29%
Charged to Operations - Wages & Salaries, Overtime & Benefits	61%	61%	64%	64%	67%	70%	70%	71%	71%
	100%	100%	100%	100%	100%	100%	100%	100%	100%
Percentage of Total O&A									
Capitalized - Wages & Salaries, Overtime & Benefits	31%	31%	28%	28%	26%	22%	22%	21%	21%
Charged to Operations - Wages & Salaries, Overtime & Benefits	49%	48%	49%	49%	53%	53%	52%	51%	50%
Wages & Salaries, Overtime & Benefits as Percentage of Total O&A (before capitalization)	80%	79%	78%	77%	78%	75%	74%	71%	71%
Wages & Salaries, Overtime & Benefits Charged to Operations Percentage of Domestic Revenue	33%	30%	25%	25%	26%	26%	26%	28%	29%