Direct Testimony of Patrick Bowman

Regarding the Manitoba Hydro

2023/24 & 2024/25 General Rate Application

On behalf of Manitoba Industrial Power Users Group (MIPUG)

June 9, 2023

Introductory Comments

- Evidence filed as MIPUG Ex.6. IR responses as PUB-16 and MH-21

- Provided testimony to Manitoba PUB in every Hydro hearing since 2001.

- Evidence in this proceeding covers 4 areas:

- Broad rate increases and financial performance (Recommendations 1-4)
- Depreciation (Recommendations 5-10). Not part of today's direct.
- Cost of Service (Recommendations 11-15)
- Rate Design (Recommendations 16-17)

Revenue Requirement and Overall Level of Rates

Rate Increases

Recommendation 1: Average increases proposed by Hydro (finalize interim 3.6%, 2%, 2%) are reasonable – given context. – Two parts:

- Context includes facts re: financial projections
- Context includes legislative regime

Context heavily defined by Bill 36 (*Manitoba Hydro and PUB Amendment Act*)

Interpretation taken in evidence –

- Hydro rate hearings need to look to the long-term scenarios.
- Bill 36 is understood to be passed and proclaimed.
- Unless amended, it is understood it will govern rate setting for periods after March 31, 2025. This is within the long-term forecast period.

Context for Manitoba Hydro Regulation - Background

Why look to long-term, not just next 2 years?

Regulating Hydro is like steering a supertanker. We can & must look well into future.

- Assess base case & sensitivities – 10 years sensible / 20 yrs challenging, but sometimes necessary.

1) Hydro existing regulatory model – Cost recovery – one of the last of its kind.
   - No shareholder equity contribution no Bay Street equity
   - Financed heavily with debt nominally guaranteed by/issued by Government
     - Debt is cheapest source of capital. Helps keep rates low.
   - Debt is backed by strong franchise, and by ratepayers
     - Necessary service, rates are low/competitive
     - Can be raised, but only at opportunity cost that removes productive capital from MB economy.
     - "Equity" means customer contributions over & above costs of power (already incl. depreciation)
2) Customers value predictability and stability, and we can provide that here

   Most other jurisdictions not so blessed (non-hydro, fuel costs, equity returns, less rate increase flexibility).

Approach to Bill 36 in evidence

Financial Targets - Am I in the wrong hearing?

Hydro has always had directional financial targets.

- Interest Coverage, Capital Coverage (cash), Debt:Equity over time.
- Provided guidance, not black-and-white requirements.
- Often changed, when facts required. Debated vigorously. Were due for testing [Order 59/18 re: Minimum Retained Earnings target]
  - Equity standards only got set first at 15%, then 25% in 1990s-2000s as Limestone returns and market results led to many years of very low to no rate increases. Setting of, and progress on, targets followed the investment benefit.
- Main purpose of targets – communication to all parties. Provided roadmap.
  - But also flexible – PUB could vary from target (with reasons), but still confirm commitment to making progress..

- Bill 36 – Appears no more reviewing financial targets here (after 2025).

BUT

- Turning targets into black-and-white requirements gives significant risks of rate instability.
- Bill 36 appears to recognize this, and instead imposes rock-solid rate cap.
  - True - No more risk of rate shock.
  - Also true - Result is lost flexibility → can't keep rates as low, can't keep reserves (equity) as low.

Turns the delicately balanced financial model on its head.

The First Bill 36 Rate Increase

- Order 59/18 described dividing risks [page 65]
  - Variable matters such as drought managed by reserves, as well as rate response
  - Trends in costs, such as interest rate increases, sustained adverse export price movements, dealt with by future rate changes when they arise.
- Can’t do that now. Can’t plan for as much rate response in future if needed.
- Consequently – we need to be on a path today to meet Bill 36 targets. Includes absorbing expected (likely) adverse future movements in next few years:
  - Refinancing $1B debt/year at higher rates than presently paying
  - Ending of NSP contract and insufficient capacity to replace sale as firm power.

May be room to vary rate path, if we can show probabilities of reaching the target are higher than suggested by the base case

- Require Uncertainty Analysis updated to draw conclusions such as this (Recommendation 3)

But For Bill 36…
Spectacular Performance

No sign of rate increase required while absorbing new capital.

Table 2-1: Comparison of Current and Previous Long-Term Forecasts

	Long Term Rate Increase	25% Equity Ratio	Maximum Long-Term Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34	Maximum Net Debt
NFAT Plan 5 – High Keeyask Level 2 DSM	3.95% 2014/15; 3.99% 2015/16 to 2031/32	2031/32	$22.490 B in 2023/24	8% in 2021/22-2023/24	Total of $638 M in 8 years during 2015/16 – 2022/23	$6.659 B	$21.606 B in 2022/23
MH14 (financial forecast from 2014)	3.95% 2015/16 to 2030/31	2033/24	$24.476 B in 2028/29	10% in 2022/23 - 2026/27	Total of $977 M in 8 years during 2018/19 – 2025/26	$5.557 B	$23.227 B in 2024/25
MH15	3.95% 2016/17 to 2028/29	2031/32	$23.495 B in 2026/27	12% In 2021/22 – 2023/24	Total of $58M in 3 years during 2018/19 – 2022/23	$7.402 B	$22.589 B in 2021/22
MH Exhibit #93 (based on MH16)	3.36% 2016/17; 3.36% 2017/18; 3.57% 2018/19 to 2035/26	2035/36	$25.560 B in 2028/29	12% In 2024/25 – 2028/29	Total of $418 M in 6 years during 2022/23 – 2026/27	$5.004 B	$24.971 B in 2027/28
FFS December 15, 2022	3.36% 2016/17; 3.36% 2017/18; 3.6% 2018/19; 2.3% 2019/20; 2.9% 2020/21; 3.6% 2021/22; 0% 2022/23; 2.0% 2023/24 to 2040/41	2035/36	$24.291 B in 2021/22	13% during 2017/18 – 2021/22	Outside of 2021/22 drought - none	$5.635 B	$23.293 B in 2021/22

Focus on cash flow – 10 years

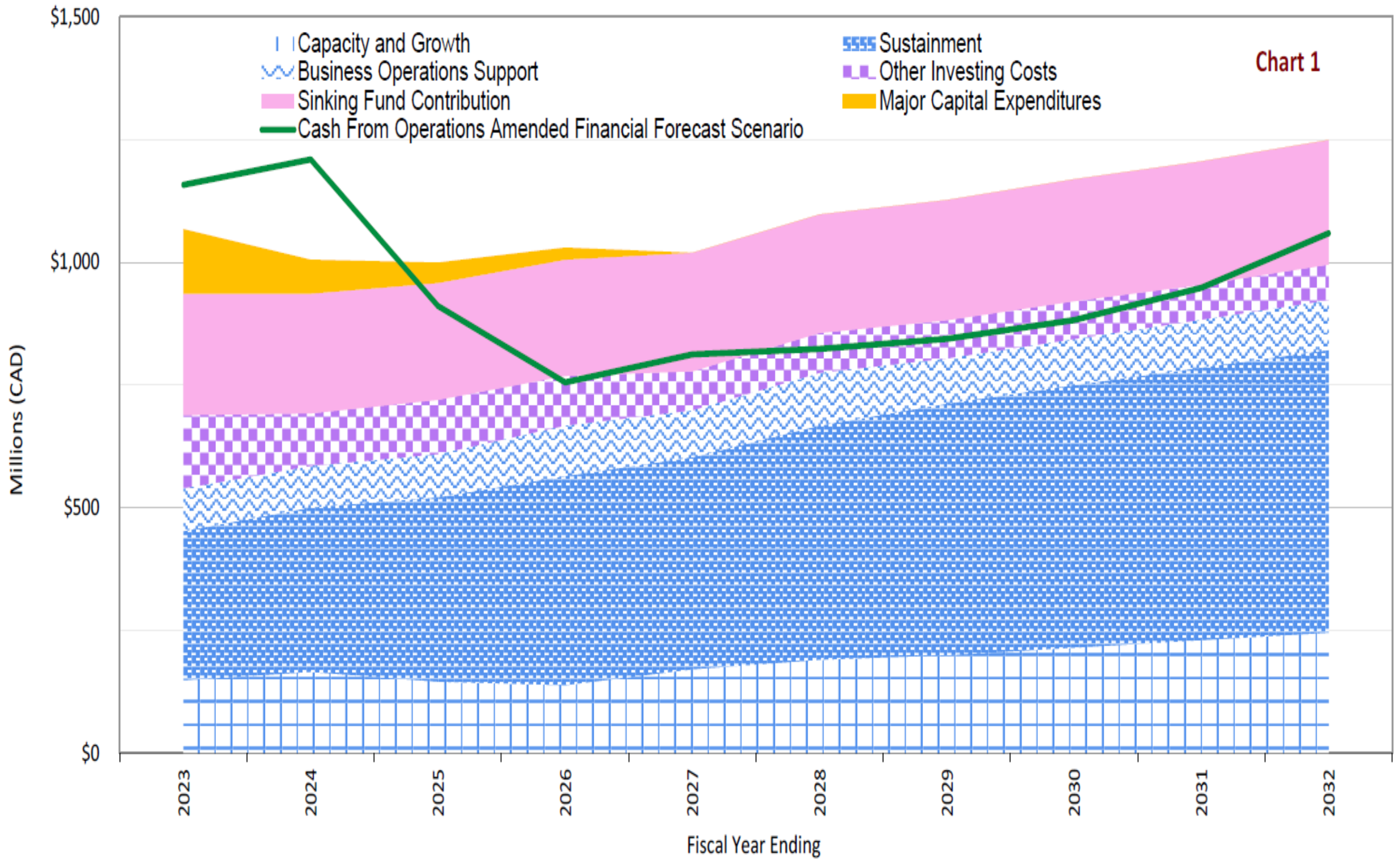
[MH Undertaking 41]

Cash from Operations is measured after paying for:

- All operating costs (at forecast)
- All interest costs
- All taxes and fees
- All water flows (average outcomes)

Cash is still financing

- All business operations and sustainment capital (at forecast)
- All other investing costs (e.g., mitigation)
- Plus: Most or all growth capital
- And – some debt repayment 2023/24 and 2024/25)



Final Notes on Rate Increase

- Not a lawyer
- Bill 36 Transition Provisions may have been misread
  - Different parties have taken different considered views in this proceeding
- Normally build into forecast things we expect:
  - Why is Bill 36 different post-2025?
- **On legal question – if incorrect, then no basis for 2% rate increase today for financial target reasons.** May still be appropriate for investment in reliability.

Other Revenue Requirement Matters

Scope did not include reviewing O&M, Normal Capital, or export price forecasts.	If Board identifies savings/benefits/undue conservatism in those areas, may be room to adjust rate increase down.
Customers can best handle/budget for rate increases once in a 12 month period	**Recommendation 2:** May want to schedule any 2024 increase to take effect 12 months after 2023 increase (September?)
Conawapa and Selkirk deferrals	Best to avoid deferrals that are only for rate-smoothing purposes. Consider discharging these balances in near-term. (**Recommendation 4**) Also room to consider start accruing for next phase of Selkirk decommissioning – closest in time to when Selkirk actually provided value.

Cost of Service and Rate Design

Cost of Service and Rate Design

- COS Methodology has changed over time.
  - Most changes are small and incremental, reflecting facts as they evolve
  - Major reviews and updates in 2005, 2016.
- Rate design has seen few changes.
  - Small changes seen in this Application (largest customers). Timid.
- Need to reflect updated facts and cost drivers.
- Today, primarily informed by key trends:
  - **Demand needs becoming more acute** – consistent with industry.
    - Challenges include decarbonization. Growing winter peaks (heating)
  - **Energy resource costs decreasing** – technology & subsidies. E.g., wind.

Role of Cost of Service and Rate Design

Cost of Service

- Analytical tool
- Based on cost causation
- Generally oriented towards informing fairness.
- Measures costs to serve a class versus revenues paid, in a Test Year (also by type of use – energy, demand, customer)
- Pervasive in utility regulation
  - Most other jurisdictions use output to set rates, except where prohibited
  - Some use RCC more rigidly (e.g., Newfoundland Hydro)

Size of Pie Slices – Inter-class Fairness

Rate Design

- Art
- Balancing multiple objectives
- Price signals important
  - E.g., Marginal costs – demand versus energy
- Generally oriented towards efficiency and stability, and other rate design objectives.

Layers of Pie – Intra-class Fairness

Differentiated Rates primarily an issue of COS, not Rate Design

Exports in COS Study

- **Recommendation 11** – Continue to use export approach from Order 59-18 – as an offset to costs.
  - Exports are directly matched with investment in assets. Need to be used to pay for assets.
  - RCC should reflect the degree of adjustment needed – only arises if exports used as offset to costs.
  - Approach is consistent with NARUC manual as well

Example for Residential in PCOSS24 (2023/24 study)

Table 4-1: Comparison of Export Revenue Treatment Approaches

$millions

		Costs		Revenues	Surplus/(Shortfall)	RCC ratio
Offset Approach		$1,352.4				
(approved)	less:	$471.2				
	total	$881.2		$831.6	$49.6	94.4%
Revenue Approach				$831.6		
(previous)			plus:	$471.2		
		$1,352.4	total	$1,302.8	$49.6	96.3%

With "normalized" water – Revenues stay the same and costs decrease to $877.0 million, shortfall drops to $45.4M

[Coalition/MH-I-155a]

PCOSS24 is appropriate for use

[Data from Coalition/MH-I-155a; Table from MIPUG-6]

- **Recommendation 12:** PCOSS24 is appropriate to use for rate setting.
  - PCOSS24 is reasonably modelling 2023/24
  - The results are directionally consistent for normalized water.
    - NOT highly uncertain, as alleged by Hydro.

Table 4-2: RCC ratios from PCOSS24 versus PCOSS24 using 2024/25 export revenues

	RCC ratio	
	PCOSS24	adjusted to 2024/25 Net Export Revenue
	ZOR	ZOR
Residential	94.4% below	94.8% below
GS Small Non-Demand	109.7% above	110.0% above
GS Small Demand	101.8% w/in	102.1% w/in
GS Medium	100.3% w/in	100.3% w/in
GS Large 0-30 kV	97.9% w/in	97.4% w/in
GS Large 30-100 kV	112.4% above	110.2% above
GS Large 100+ kV	113.2% above	110.5% above
Area and Roadway Lighting	108.2% above	112.0% above

Have used past PCOSS for rate setting

Last 3 proceedings

- Much more transition and uncertainty than today
- Still used the results to guide rate changes.

Proceeding	**2021 Interim**	**2019 ERA**	**2017/18 GRA**
Source	PCOSS 21	Estimate only	PCOSS 18
Issues w/ study	Incomplete Keeyask	Estimated Bipole	
GSL >100kV RCC	101.2%	101.9%	112.3%
Rate Change GSL>100kV	3.8%	2.5%	3.36%
Rate Change average	3.6%	2.5%	3.6%
Proposal	No Bowman evidence [MIPUG recommended average]	Bowman Evidence recommended average	Bowman Evidence recommended small differentiation (rejected large move)
Order	9/22	69/19	68/18

PCOSS24 Improvements

- Need to remain aware of growing importance of peak demand.
- In 2005, methods were updated for growing importance of energy
  - generation classified to 100% energy, and to time periods based on relative export values.
  - In 2016, methods revised back, as focus shifted.
- Now – it is demand that is growing importance.

- Demand is critical to future utility planning
  - Loss of diversity arrangements
  - Poor options for meeting future demand needs
    - Good options for energy (e.g., wind)
  - BC Hydro revising Industrial rate designs to reflect more focus on demand (ongoing BCUC review)
- PCOSS should have a growing eye to this evolution

PCOSS Method Updates

- Manitoba PCOSS methods merit small updates:
  - Wind – does play a role in capacity, but presently allocated 100% to energy.
    - Hydro rebuttal notes nothing new re: asset – wind always gave small capacity benefit
    - New issue is not the wind capacity, it is the way we recognize (and plan for) the value of wind.
    - Undermines System Load Factor approach to generation.
  - DSM – overly allocated to generation (primarily energy) and not to wires.
    - Previous debates (2016) primarily focused on whether to allocate to customer vs. system – not focus as much on parts of system.
    - DSM does give benefits to other functions, not just generation. Role will grow.
    - Example of LED streetlights
  - The way we measure peak (1 CP) – 50 hours x 8 years is too broad.
    - Highest hour is 4519 MW; 50th highest is 225 MW lower. Centra COS decision recognized highest period.

Differentiated Rate Increases

- Range of possible reasonable outcomes
- Also range of unreasonable outcomes.

What is a ZOR?

COS is known to be an imperfect science.

- Argument supports idea there is a zone of reasonableness
- Outside of this zone – rates are not reasonable.

Within zone, should balance competing priorities

- Example – stability.

Does more imperfection mean less focus on results – No.

The more imperfect the methods, the more important to push for 100% (unity)

ZOR is not a free pass to sit at approximately 95% RCC for decades

Persistent Challenges re: Zone of Reasonableness (ZOR)

Can we rely on past studies to indicate trends?

- Some are <u>clearly</u> not consistent – e.g., when exports were proposed by Hydro to be allocated to distribution, as in PCOSS02 (from 2002)
- Some have incomplete sets of facts – e.g., PCOSS21.
  - Includes most costs of new Keeyask generation, but not revenues.
  - <u>Still – PUB used the study to differentiate rates</u>.
- Pattern is relevant for assessing long-term fairness
- Also basic claim that RCC ratios will be self-correcting.
  - Has been asserted many times over 30 years – has not occurred.

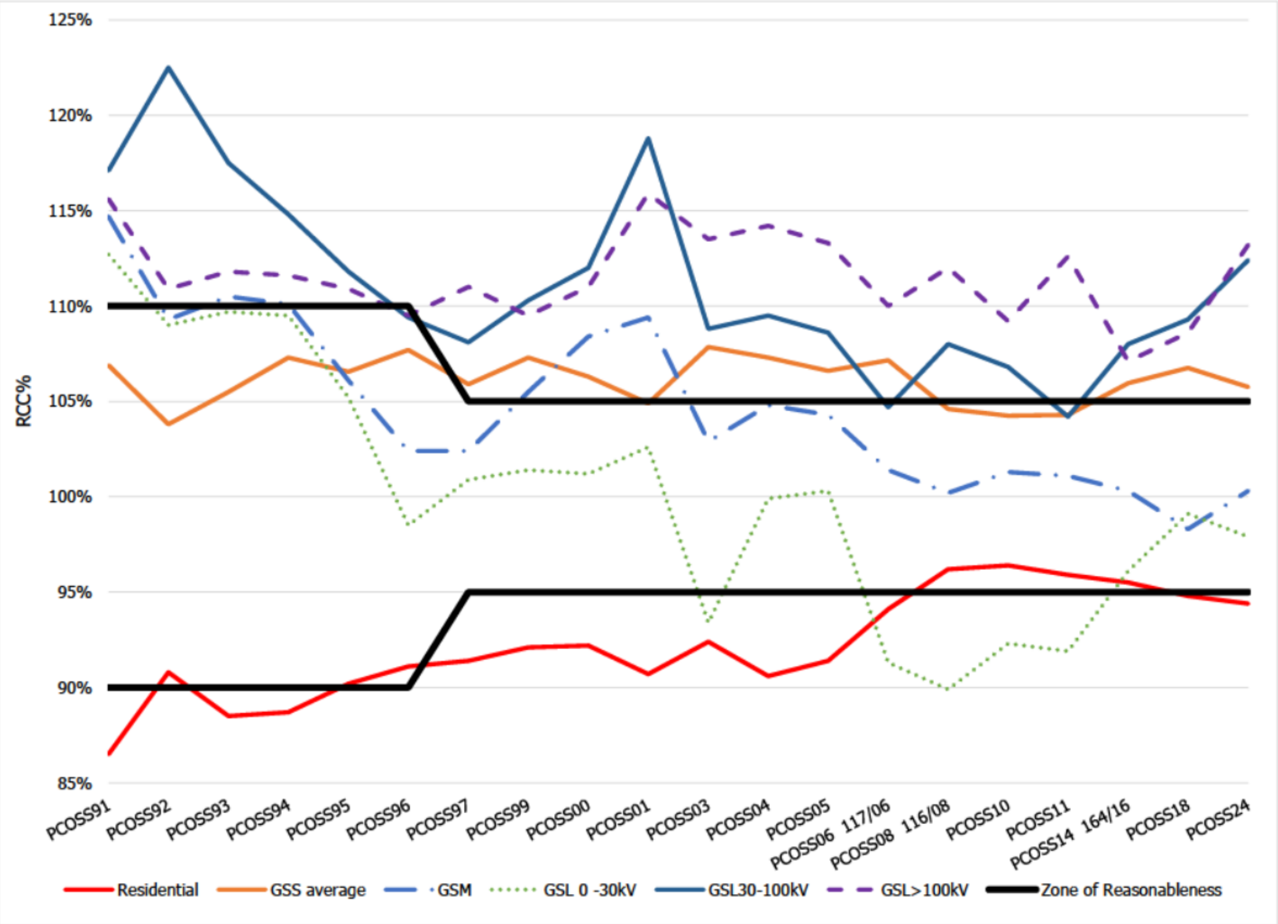
ZOR history

Full PCOSS studies approved or used to set rates

Excludes PCOSS21 – potentially should be included.

Recommendation 16:
Continue to differentiate rate increases.
Aim for outer bound of ZOR as soon as practical – (e.g., 2027/28; 10 years).
Use PCOSS24

Figure 4-1: Manitoba Hydro PCOSS RCC results since 1991



RCCs uncertainty presently favours small customers

Examples:

1) Move towards more weighting to demand.
2) Fail to reflect peak uncertainty and capacity reserves.
3) RCCs fail to reflect the role of distribution.

Skews results as illustrated.

All values per PCOSS24 ($millions)

	Total	less: Dist&SubTrans	Generation & Transmission	less: Net Exports	Net G&T
Costs					
Residential	1352	378	974	471	503
GSL >100kV	282	3	279	135	144
Revenues					
Residential	831	378	453		453
GSL >100kV	167	3	164		164

	G&T RCC
Residential	90.1%
GSL >100kV	113.9%

Rate Design

- Layers of the Pie
- Provides price signals, efficiency
- Customer Charges, Demand, Energy, Blocked Rates
- Fairness to different customer types
- Should apply to homogenous customer types [GSL 0-30kV problematic]

Rate Design Recommendations

- GSL Rate Design (**Recommendation 17**). Broadly:
  - Continue to move to more optionality in rates (e.g., Time-of-use, curtailable)
  - Adopt on-peak focused demand charge
    - No need for off-peak caps at 110%
  - No need to increase rates $0.09/kVA to make up for “lost revenue” ($900k) on classes that are overpaying by $31M
- Example of the balancing part of Rate Design.
  - Efficiency and Marginal Cost signals indicate a need for more emphasis on industrial demand.
  - However, customer impact challenges how far the Board should go in one hearing.