MANITOBA HYDRO 2014/15 and 2015/16 GENERAL RATE APPLICATION

MIPUG FINAL ARGUMENT
WRITTEN SUBMISSION
June 18, 2015

MIPUG Final Argument: Summary of Recommendations

1. Finalize the previous 2014/15 rate increase of 2.75%, effective May 1, 2014.
2. Going forward, adopt the following stepped approach for Board approval of new rate increases for 2015/16 and subsequent years taking into account the current unprecedented bulge in capital spending on Bipole III and Keeyask:
    a. Approve for 2015/16, effective after the Board's Order, a rate increase of no less than 2% and no more than 3%;
    b. Provide guidance that at the next few GRAs, the Board will use the opportunity to review thoroughly each proposal for rate increases in light of facts then prevailing including interest, market conditions and water flow conditions at that time, as well as the status and timing for resolution of other key external factors affecting Hydro's future rate revenue requirements over the next decade, e.g., Manitoba Government direction and decisions regarding implementation of ongoing DSM, resolution of Hydro's financial targets review, final steps in moving forward with the US Great Northern Transmission project, EPA decision affecting future export pricing, and Hydro's review of long-term Conawapa deferral; and
    c. Provide guidance that annual rate increases higher than 2-3% are not impossible in future years should conditions warrant (e.g., drought), but that Hydro will be required to demonstrate that all reasonable measures to avoid this outcome have been thoroughly pursued, and will be investigated in detail by the Board, including measures to identify and assess pacing and prioritization options for capital and O&M spending, DSM spending, and appropriate management of financial targets in the context of current and forecast conditions.
3. Approve ongoing determination of Hydro net income for rate regulation purposes that addresses intergeneration equity and fairness for an integrated Crown electric utility reliant primarily on hydro generation and transmission bulk power supply, and includes the following directions:
    a. Continued capitalization for rate regulation of O&M costs that are currently capitalized (approximately $60 million/year improvement compared to IFF14);
    b. Approve Hydro’s request for elimination of ongoing accumulation of net salvage charged through depreciation;
    c. Retain Average Service Life (ASL) depreciation for rate regulation, without any net salvage charges, and including the latest updated life estimates for all depreciation accounts;

d. For future GRAs, modify the depreciation study as required to further componentize significant categories of assets which have materially different life estimates.

e. Retain amortization of DSM expenditures, with amortization periods to reflect the reasonable expected life for benefits from each programs without an arbitrary cap at 10 years for programs with benefits that exceed this horizon.

4. Revert caps for participation in the Curtailable Rate Program (CRP) to the levels last permanently approved, removing the interim lower caps imposed in the last GRA. Recommend that Hydro assessments of CRP in future reflect the long-term value for the overall grid as well as for enhancement of local regional transmission reliability. Recommend that Hydro continue to pursue enhancements to CRP and to explore other demand side management programs with major industrial customers.

5. Recommend that Hydro retain responsibility for planning and delivering DSM programs for industrial customers.

6. Recommend that Hydro and the Manitoba Government examine options for adjusting Provincial capital charges, debt guarantee fees and water rental charges during the period of unprecedented capital expansion in order to reduce rate increase burdens on Manitoba ratepayers from the new generation and transmission assets until such time as Hydro's equity ratio recovers to at least 20%.

TOPIC #1: Financial Issues - Cash Flow Related Rate Requirement

ISSUE:

Is cash flow analysis an appropriate method to use for rate setting? Does Hydro's current cash flow projection indicate an overriding need for 3.95% rate increases?

MIPUG RECOMMENDATION:

Cash flow is not the normal tool for determining appropriate rate levels, though it can be informative. In this proceeding, Hydro's cash flow over the next decade, under any of the rate increase scenarios modelled (3.95%, 2% for one year followed by 3.95%, or 2.5% for four years) the cash flow on operations remains highly positive and sufficient to fully fund the new extraordinary Sustaining Capital levels projected by Hydro. This occurs despite the need to absorb large cash shortfalls from the initiation of Bipole III and Keeyask. This is reasonable, if not exceptional, cash flow projection given the facts of today's capital expansion program.

For this reason, the cash flow projections do not justify an absolute need for 3.95% rate increases today and MIPUG recommends a rate increase in the range of 2-3%.

DISCUSSION AND SUPPORT:

Manitoba Hydro Position

Manitoba Hydro's position, as confirmed by Mr. Thomson on May 26, is that cash flow is the major driver of this 3.95% rate application. [T446, lines 15-19] Throughout this hearing, Hydro has maintained that 3.95% is required for the test year of 2015/16, and for each subsequent year for more than 15 years to come, in order to meet its long-term financial targets.

Mr. Rainkie and the Finance Panel elaborated on why Hydro sees cash flow as being the rate driver at this time - advising the Board that we must look at what's ahead of us, the doubling of Hydro's cost of service in the next 10 years due to the bulge of major new investments for Bipole III and Keeyask, and the deterioration in Hydro's financial ratios as debt increases. [T2023 line 12 to 2025 line 11] Hydro has told the Board that the 10% equity ratio forecast for 2023 with ongoing 3.95% rate increases is the minimum ratio acceptable to Manitoba Hydro to maintain self-supporting status. [MH-52, slide 10] Hydro has suggested that failure to secure 3.95% rate increases today will result in

ratepayers facing much higher rate increases by 2020 in order to achieve the minimum required 10% equity ratio by 2024. [MH-31, slide 41]

On the last day of the hearing, Mr. Rainkie re-stated Hydro's view that the 3.95 percents for ongoing rate increases today and in the coming years are the minimum required - stating that "finance expense is really the truth serum of our forecast", and suggesting that a higher 5% rate increase could be advocated for each of the next three years to help at least cover sustaining capital expenditures from cash flow and to reduce future finance expense after the bulge in major new capital spending. [T3786-3794]

MIPUG's Expert Evidence

MIPUG's expert witness, Mr. Bowman, reviewed in detail Hydro's cash flow forecasts. He advised the Board that Manitoba Hydro's cash flow forecast, with the 3.95% rate increases through the heavy investment period of the next 10 years, is not bleak, and reflects what is to be expected during the current investment period. [MIPUG-12, slides 28-29, supported by MIPUG Exhibit 14 which provides the electronic calculations behind the analysis]. Unlike the forecasts in the NFAT hearing when Hydro was proposing Conawapa, the expected bulge in capital spending is now somewhat higher annually, but much shorter in duration. [MIPUG-12, slides 21-22] The projected operating cash flow <u>surplus</u> each year of the entire 20 year IFF scenario exceeds $400 million per year. After 2017, operating cash flow falls below the newly increased sustaining capital projection while Bipole III and Keeyask cash shortfalls are absorbed into Hydro’s system, but this is more than compensated for by larger surplus on other years of the next decade yielding a cash flow over the first 10 years of the IFF that is able to fully fund operations, all sustaining capital (even at the new higher projected levels) and still have a surplus for debt management or cash flowing a small part of the Major New Generation and Transmission projects.

MIPUG's position is that Mr. Bowman's analysis focused on the key cash flow indicators that the Board should consider when assessing rate increase requirements related to cash flow.

Mr. Bowman also showed that setting the test year rate increase well below 3.95% - in the 2 to 2.5% range - combined with historic vacancy rates did not undermine Hydro's forecast cash flow ability over the next decade to cover all operating costs, interest finance cost, early year Keeyask and Bipole losses, and sustaining capital requirements such that a portion of old debt is expected to be paid down as well. [MIPUG-12, slides 26-29, T3898-3906]

More importantly, Mr. Bowman noted that a lower rate increase in the test year or in the next few years provided opportunity to examine ways to reduce rate increase pressures

for the rest of the next decade without removing the Board's ability within the next few years to approve 3.95% or other rate increases if it became required during that period such as for a drought. [MIPUG-12, slides 26-29, T3898-3906] Mr. Bowman did not agree that approving lower rate increases today in any way supported an expectation that, absent some serious new problem, rate increases higher than 3.95% will be required three years from now. [T4132-4133]

Mr. Bowman noted in his cash flow review that there are actions that Manitoba Hydro could take internally today to improve its cash flow forecast position (apart from rate increases), including pacing and prioritization of spending on items such as DSM and sustaining capital, and recognizing the likelihood of higher vacancy rates than forecast. He also noted that the cash flow forecast could be further improved if interest rates remain lower than forecast, or if any government relief was provided during the bulge period related to current fixed charges on capital spending and/or water rentals.

Based on his review of cash flow forecasts and rate regulation principles, Mr. Bowman recommended a step wise approach for rate setting today with an increase for the current test year (2015/16), and potentially the subsequent 2 to 3 years, more in line with inflation, at between 2% to 3%, prior to future rate decisions as to what rate increases are most appropriate thereafter to deal with the bulge in capital spending. [T4118, line 7 to 4133, line 5]

MIPUG supports Mr. Bowman's recommendation for a step wise approach with today's test year rate increase in the 2 to 3% range. MIPUG urges the Board to use this approach to set requirements and challenges for Hydro to address in its next rate application - including meaningful assessment of pacing and prioritization options for capital and O&M spending and how such options could reduce future rate increase requirements below Hydro's current 3.95% default case.

ADDITIONAL RELEVANT MATERIAL

Financial issues are fundamentally different between income statement and cash flow. As noted in discussion, rate hearings typically focus on the income statement – however, in this proceeding Manitoba Hydro has primarily chosen to be focused on cash flow arguments.

With respect to income statement and balance sheet status, Hydro's focus on keeping its equity at $1.7 billion or higher is misplaced:

1. The level is arbitrary in light of the current review of financial targets,
2. The level is not reasonable in light of the current investment spending bulge and this utility's history (when the record shows equity ratios well under 10% for long

periods in the past), or the recent amended agreement that Hydro has entered into with NCN regarding the Wuskwatim partnership (where the equity ratio will now be allowed to fall below 10% to deal with initial year financial under performance); and,

3. The level reflects retained earnings levels in excess of the estimated cost of a 5 year drought throughout the period of intense capital spending pressures. This is an exceptional level of financial protection for Hydro, that has not been present until at best the last few years. (Hydro's debt: equity had been on a multi decade path to attempt to reach the 25% equity level, approximately equal to the cost of a 5 year drought. The IFF14 projection shows that, unlike the last 2 decades, where that level has been the gold standard to reach, the retained earnings exceed this standard and will continue to meet or exceed it in each year of the challenging decade).
4. Hydro's cautions over debt:equity levels ignore the surplus depreciation of approximately $1 billion on assets, which is an additional financial strength of the company that is not otherwise recognized in the financial targets.

The evidence provided in this proceeding is that Hydro is in a very good financial position for the test years, more than holding its own during a period of significant investment - there is no evidence of a crisis that would need to drive near term rate requirements.

- Financially Hydro's rate proposals in effect outline a plan that requires ratepayers (through a series of 3.95% rate increases) to absorb major capital investments such as Keeyask and Bipole, reinvestment in existing assets, investment in DSM (including absorbing lost revenues caused by DSM) and optional major accounting changes that Hydro proposes to apply. Hydro is planning to deal with the "bulge" in investments entirely through rate increases and without looking at any other options or measures.

- Good financial performance - if anything Hydro's near-term financial performance is slightly better today than forecast last GRA: Overall IFF is slightly better for the first 3 years (2014/15 to 2016/17) and then worse the next 7 years and thereafter [MH-31, slide 49 - MH14 vs MH13 electric operating net income forecast with proposed rate increases].

- Favourable changes since last IFF re: near term water (increase) and interest rates (decline) - both factors can have large impacts on IFFs, i.e., removes an immediate basis for 3.95% rate requirement. Note that the US exchange rate does not impact these matters due to hedging (T, p. 992-995)

- Exceptional financial performance given the decade of investment with no outside help from the provincial or federal government (unlike past examples of major investment in Manitoba, or current examples of major investment in BC or Newfoundland) and in fact a negative pressure being added by the provincial government in the form of added debt guarantee fees and capital taxes each time Bipole III's cost estimate is raised. With extra pressure from combining major expansions plus major existing system reinvestment, Hydro is still holding its own on cash. A reasonable return to positive net income after projects are completed is a high test. [MIPUG-12, slide 12]

    - Pacing and prioritization of capital spending, wherever feasible, merits attention and reporting to look for ways to reduce rate increase requirements during the next 10 years of bulge in capital spending.

    - Timing shifts in sustaining capital spending can also potentially enable such spending to reflect available operating cash flow in all years (without material temporary cash flow shortfalls).

    - Demand Side Management (DSM) spending during this period merits review to avoid adding to operating cash flow issues when export prices are low, other capital spending is in a bulge period, and a large amount of new hydro generation is coming into service.

    - Impacts from variables like O&M escalation and vacancy rates can also affect cash flow from operations.

    - Note extent to which there are also various other matters being addressed over next year or so that may have major impacts on cash flows and rate requirements over the next 10 to 15 years, e.g., clarification on DSM responsibilities of Hydro vs Manitoba Government (and confirmation of how these may affect Hydro's cash flow), final steps re: US transmission line, EPA decision affecting export pricing, financial target review, review of long-term Conawapa deferral.

    - The hearing has confirmed that there is uncertainty today regarding who is implementing future DSM programs, how costs are shared or expensed, and how this could affect future Hydro cash flow projections both as to revenues and cash costs. Effects on long-term debt are also expected if Hydro is not expected to carry the investments on its balance sheet.

- Financial performance over the IFF period will be driven by the "bulge" in capital spending - guidance from longstanding regulatory literature is that assets should not

drive rates until “used and useful”; and should not drive rates if not “prudently acquired.” As Mr. Bowman noted:

> And -- and I just put for reference there that, from a regulatory perspective, there's a few really important drivers. And I can pull out the textbooks if you want, but a lot of this is about -- about making sure that assets make it into rates at the time that they're used and useful for providing service to ratepayers, and they're -- don't make it into rates if they're not prudently acquired. [Tr. Page 3890-91]

- Can review financial targets at next hearing
  - Debt: Equity
  - Interest Coverage Ratio
- Role of Crown utility - Mr. Bowman described the role of the Crown in developing major power projects as follows:

> And in Dece -- last December, after the NFAT had concluded, the BC government announced it was going to change the way that it charged hydro government charges for the Site C project and reduce the cost of Site C by twenty-six dollars ($26) per megawatt hour, two point six (2.6) cents a kilowatt hour. That -- and that's in press releases. It's fairly public information. That's how they came to the table to transmission planning to bulk assets, and it's relevant for a couple of reasons. One is because these aren't just power projects. They have a major public policy aspect -- public interest role.
>
> The second is that these projects would not be possible if we traditionally financed them. And it's more than just debt guarantees for which you charge a fee. There's other approaches to looking at it, and I'm going to -- I can give some examples of that. The role of the Crown can also lower the overall costs, reduce -- you know, reduce expectations of returns because you don't put any equity and – and save on taxes and -- and in a big way reflect this -- this patience and risk management that's available that -- that wouldn't be possible with a private equity investor who's trying to report their quarterly earnings or pay a dividend every year to -- to their shareholders. [Tr. P. 3876-3877]

- Historic precedent for bringing in large capital projects - Prior Manitoba Hydro experience in developing major infrastructure projects as noted as follows:

> An example also here is, when Manitoba took on the Lake Winnipeg regulation and Church River diversion, there were -- were much more limited charges in the hydro structure. Provide for different financial structure for projects. And -- and again, things that people of a previous generation here understood, Bipoles I and II when they were developed, associated with the northern projects, were too big for Hydro to take on. All -- all -- a number of reports that will deal with that. And they had some technological risk. I don't know how many people here know the history, but as a result, those projects were not built as Manitoba Hydro projects. They were built as projects of Atomic Energy of Canada Limited who leased them back to Hydro. And the lease rates were organized so that in the early years, the payments were very, very small. Like my recollection is they were, you know, $2 to $5 million for a period of time, and they escalated with time. And that's a lease rate that's incorporating both the interest and the depreciation aspect of the project. It's almost equivalent to jumping to a negative deprecation rate and you're not even paying your interest. But it's part of putting in the big projects that provide this long-term benefit. And, you know, that was central to Hydro's ability to go -- to go north. [Tr. P 3879-3880]

- Sustaining capital – extremely difficult topic for regulators and intervenors [MIPUG-12, slide 24; Tr. P 3893-3898]
    - Information focused on staff level – why this project versus that chosen within the budget limit – rather than executive level about how the budget limit was determined, allocated and prioritized. In this hearing, for example, Hydro did not explain the basis for overall decisions re: options for funding allocation to sustaining capital overall or by major Divisions or any attempt to assess options on such spending that would change rate increase requirements (MH Exhibit #115 was provided only on June 14, and still did not address these matters).
    - Regulatory onus on the utility is key to managing issue (reference to other jurisdictions such as Newfoundland PUB)
    - OEB report highlights some approaches (categorization, prioritization, performance reporting, reliability metrics) - see response to COALITION/Bowman-3.
- Operating cash surplus and sustaining capital

- Manitoba Hydro did not provide any analysis regarding what it would do to pace and prioritize spending with rate increases lower than 3.95% (and avoided answering an undertaking on this issue).

- Manitoba Hydro evidence about needing 8% rate increase in future years if only have 2% increase for next few years - this presumes all projections of all cost and revenue items over this period are correct, i.e., ignores the real issues re: internal capital and operating cost control and re: need to justify why such overall increases are still prudent and fair and reasonable given deferral of Conawapa, good current water conditions, low interest rates etc and point that ratepayers are looking for truly reasonable stable long term rate increase requirement that is (if possible) lower than 3.95% per year

- Evidence provided by Mr. Bowman shows that with current assumptions, Hydro is not borrowing cash to operate over the bulge period (and also fully absorbs operating cash impacts of $275 Million/year for Bipole and $80 million/year for Keeyask (cash cost less export revenues). [MIPUG-12, slide 25; Tr. 3898-3901. Mr Rainkie agreed with Mr. Peters that Hydro has a strategy to manage through this period without borrowing to pay interest. Tr. 2068 line 23 to 2069 line 14]

- Evidence provided by P Bowman shows what happens with operating cash flow if, with historic vacancy rates, the Board grants 2% today or grants 2.5% today and sustain for 4 years. [MIPUG-12, slides 26-29, Tr. 3902-3906]

- Mr. Bowman concluded [MH-12, slide 28; Tr. 3904, 3908] that outside of the four long-term projects any of the three rate increase scenarios that he examined:

    - All operating costs and interest covered by cash from operations

    - Keeyask and Bipole III early year losses absorbed

    - All normal capital over 10 years is financed by cash flow

    - Old debt is paid down (by $0.7 B with 3.95%; $0.4-$0.6B under scenarios); occurs despite present context – large increases in Bipole costs, heavy sustaining capital reinvestment, low gas/ export prices, opportunity for low interest rates.

- Mr. Bowman further concluded on cash flow and rates (MIPUG-12, slide 29; Tr. 3905]

- Some challenges, but entirely as expected during major phase of build out of new assets, overlapping with major re-investment in old assets.

- Picture is not bleak – for the most part cash is tracking sustaining capital. Where it is not tracking is the first few years of Keeyask and Bipole

- Even if it was not tracking well, this is to be expected during the current investment period. Cash flow is not the problem.

- Cash flow over this period would benefit if DSM was reduced, interest rates remain lower than forecast, higher vacancy rates than forecast, or better O&M cost control. Also any government charge relief.

Additional References:

DSM

Mr Bowman at Tr. p 4023

> Yeah, we can -- the next slide was just briefly on DSM. And it was just to help summarize, I think we've been over this, but that there has been a significant increase in the DSM spending and amortization since the previous GRA, which is no surprise to anyone who was at the NFAT hearing. It's just to note that this is -- does have an adverse impact on cash, particularly given the low export revenues, to replace the lost domestic revenue.
>
> So if you get a person to stop using a kilowatt hour through a DSM program, that person saves the cost of 1 kilowatt hour. If they're an industrial customer, it's four (4) cents. If it's residential, it's closer to eight (8). Hydro loses that revenue, but it has a kilowatt back it can go sell in export markets, and it can make whatever it can make from it. If it's opportunity, it might be making between two (2) and three (3) cents. So not only have you spent money on the DSM program, but you've lost the -- the revenue. And those two (2) combined give you the cash impact in the year where the savings occurred and the program was run. Of course, that -- that savings value will change if that kilowatt hour can be sold for more as years go on. That's why it's an investment, right? The -- one (1) of the problems that arises is that DSM's values to show that it's worthwhile are done on the long-term marginal values, up to thirty (30) years depending on the type of DSM program, but the costs are amortized over ten (10). If the DSM's only giving you ten (10) years of savings, looking at the ten (10) years ahead of us and the -- the market values, it's -- it's really hard to justify a DSM program. You -- the -- the -- these -- these programs pay for themselves, particularly when you look at those marginal values in years 10 to 20. And so you -- you have to make your decision now about to what extent this can play a role in overall managing of cashflow.

Debt Equity

> MR. IAN PAGE: When I first started with the company, it was -- I think it was 95:5. And then it deteriorated a few years -- well,

again, as I mentioned, as we had Limestone debt and had some -- some losses. So we -- we've -- we've come a long way.

MR. BOB PETERS: 95:5, approximately what year, since I don't recall your CV?

MR. IAN PAGE: The 95:5 would have been -- I guess would have been about 1988. (Tr. 2008)

MR. ANTOINE HACAULT: So but today what you're saying is that this Board should have some comfort in the fact that we aren't starting from a 95:5 position, and we're starting from a much better position than we were when we faced the same challenges back in the late '80s, correct?

MR. IAN PAGE: Yes. And in order to maintain that financial position, that's why we have the 3.95 percent rate increases there. And they're -- they're spread out, and we're -- we're able to absorb a bit of a drop in the equity ratio in -- in those years because we're in a strong starting position. If we -- if we were starting from a 95:5 position we wouldn't be able to say, Well let's have some three point nine-fives (3.95) and let the debt- equity ratio slip because we just wouldn't have that room. So it's important to recognize that we have that financial strength now, and to be careful we don't squander that. (Tr. 2403)

Interest Coverage

Even in the worst year Hydro has a substantial ability to pay interest:

MS. LIZ CARRIERE: The EBITDA interest coverage in 2022 is one point three-four (1.34).

MR. ANTOINE HACAULT: Okay. So that puts the point eight-five (.85) coverage ratio in perspective, because Mr. Manny Schulz, who likes cash, although I know we want to use it for sustaining capital, we've got a one point three-four (1.34) coverage in the worst year under this IFF, correct?

MS. LIZ CARRIERE: That's correct.

MR. DARREN RAINKIE: Mr. Hacault, the reason we have that calculation is we were looking at - one (1) of the recommendations

> from KPMG is to look at changing our interest coverage calculation to just that, an EBITDA calculation. The average in the Canadian utility industry of an EBITDA calculation is about one point eight (1.8).And I would think that your members would probably be looking at -- I shouldn't speak for them, but would be probably looking at interest coverage of two and a half (2 1/2) to three (3) times to be able to borrow debt, so certainly even at that one point three five (1.35) interest -- EBITDA interest coverage is not stellar. (Tr. 2415)

See also MH Exhibit #70 for EBITDA interest coverage ratio for MH14 and the 2% alternate rate increase scenario.

- The years 2020 and 2021 are the years with the lowest ratio under MH 14, and the EBITDA interest coverage in that year is 133%.

- Assuming the 2%/year alternative rate increase scenario to 2024 (and 3.95% 2025 to 2031), the lowest ratio for EBITDA interest coverage is 112% in 2022.

ISSUE TOPIC # 2: Sustaining Capital

ISSUE:

Hydro has increased the estimate of sustaining capital investment required over the coming decade by $1.1 billion from CEF12 to CEF14. Can this projection be relied upon in setting rates? What options are available to the Board to manage these cost increases?

MIPUG RECOMMENDATION:

The Board should review sustaining capital projections today with a degree of caution given the timing of their appearance in the short window after NFAT and before a GRA. Rate proposals should be maintained for only the near term (2015/16) while Hydro is directed to address pacing and prioritization of the investment levels. In the meantime, regulatory measures should be developed to ensure effective regulatory oversight of these costs as part of rates.

DISCUSSION AND SUPPORT:

Following the elimination of Conawapa in the NFAT, MIPUG expected to see substantial cost decreases in capital spending for this GRA. However, while Conawapa capital has reduced, this has been replaced by nearly "half a Conawapa"[1] of new spending. While Bipole increases make up a substantial part of this added spending, the increases in sustaining capital (all capital projects which are not Major New Generation and Transmission) are extraordinary. These replacement expenditures have the characteristic of becoming part of rates sooner than Conawapa, and at faster levels of depreciation, without the revenue that Conawapa would have brought. As a result, there are very substantial impacts to Hydro's revenue requirement in the medium-term.[2]

There are three major issues for the Board related to sustaining capital:

1) The large increase in capital spending estimates was not provided to the Board at the time of the NFAT review one year ago, even though this information has been compiled over the past number of years, and even though it would have been material to the Board's deliberations about the capability of Hydro to handle the rate impacts and the risks associated with the Preferred Development Plan.

[1] Tr: 3892
[2] Summarized from Patrick Bowman direct testimony, transcript pages 3863 - 3864

2) Hydro has provided little in the way of information about how the Corporation as a whole managed the entire envelope of sustaining capital budgets in a manner that reflects pacing and prioritization attentive to the financial headwinds faced by the Corporation attempting to integrate Wuskwatim and Keeyask and Bipole III as well as challenging new IFRS financial policies[3]. Considerable information was provided as the hearing progressed about the minute details of each department's 'bricks and mortar' wish lists, but other than a single brief and token Undertaking (MH Ex. 155) almost no information is provided on the consideration and diligence performed at the senior levels

3) The review of sustaining capital plans are always a difficult regulatory subject as it is hard to not be overwhelmed with detail that is, ultimately, not determinative to the key regulatory questions – is the right capital being spent, on the right things, and in particular with the right pacing and prioritization. The Board can take guidance from the work of other regulators on these matters, such as the OEB report provided by the Coalition in the interrogatory Coalition/MIPUG-3.

Hydro's direct testimony and presentations on planning & operations provided a preliminary outline showing the need for additional capital investment in the sustaining capital program, the proposed allocation of this investment over the next decade, as well as describe the framework used by Manitoba Hydro to manage and prioritize this investment[4]. At least three major issues remain outstanding:

1. Hydro's forecast sustaining capital expenditures by department appear to be largely discretionary or placeholder amounts.

2. Hydro's Asset Condition Report (Appendix 4.2) the main tool to determine future sustaining capital spending, fails to provide any understanding, analysis, recommendations or plans on the timing of future spending requirements. Further the Asset Condition Reporting framework has been in place for a number of years and despite this it did not help Hydro be aware of its sustaining capital spending requirements one year ago when presenting the NFAT materials to the Board.

   In conversation with the Chairperson regarding the confidence in the forecast budgets set for sustaining capital, Mr. Rainkie pointed to the Asset Condition Report for providing the information to prove the costs are justified:

[3] Tr: 3866 – 3867
[4] Transcript page 724 by Ms. Sandy Bauerlein

THE CHAIRPERSON: You know, I think we'll have an opportunity to test some of these numbers. I guess one (1) of the concerns I have is around how finely tuned are these numbers. I mean, are - is it just cut with an axe or is it -- and I'll tell you why I'm asking the question. Because the very first day we heard Mani -- we heard the city of Winnipeg say: Manitoba Hydro is not able to identify the location of any of the lights that show up in our bills. We have no idea if the count of luminaries is correct because Manitoba Hydro cannot confirm the count. They cannot confirm the existence of any of the lights that they say they operate and for which they bill us. So that doesn't inspire confidence in me that we're -- the numbers we are being asked to approve for sustaining capital is based on hard data that justifies the expenditure. And I guess that's the kind of thing I need to have some confidence in because, you know, being -- we're being asked to approve 5 or 600 -- $700 million. Is it -- is it sound numbers or is it based on hard evidence that justifies that kind of expenditure? And I...

MR. DARREN RAINKIE: That's a fair question, sir. And -- and what we tried to do in Tab 4 of our application with our hundred and seventeen (117) page asset condition report is -- is try to provide far more evidence than we ever have in the past through these rate proceedings on -- on those requirements.

And, of course, just like any forecast, the near term -- the near years are probably more accurate than -- than they go out. As -- as I just said, everyone that has common infrastructure is grappling with the issue of when, where, how you fund it and -- and -- but the -- the numbers, I think, are more solid than they ever have been because now they're based on much more detailed information through the asset condition work that the three (3) fine folks to my -- my left have been heading up over the last number of years.

I'm more confident in the numbers than I ever have been myself. And hopefully through the questioning of this panel we can get your confidence level up, as well, on -- on that. That's why we brought the individuals here that we did. Typically, we haven't had a planning and operations panel. But we thought that it would be

> good for the Board to be able to talk directly with the folks that manage these assets. (Tr: 881 – 883)

Unfortunately, Hydro Asset Condition Report does not provide strong linkages to actual performance of the assets, as noted in PUB/MIPUG-14. That response indicates that for regulatory purposes, a strong linkage between performance (e.g., reliability) and spending is required. For example, the Asset Conditions Report indicates that Generation Forced Outage Rates have seen a recent increase, but provides no linkage as to whether the assets that are being reported as being in poor condition, and a priority for replacement, are actually responsible for the reduced reliability performance[5].

Additionally, the report states that equipment at the end of its life tends to experience increased failure rates, however SAIDI and SAIFI values for Manitoba (which Hydro says are used as an indicator for capital spending) have been largely consistent in terms of outages and outage minutes, besides one peaked year in 2012 and the scores are amongst the lowest over the past 10 years for 2013[6]. Hydro indicates it is starting to see the SAIDI and SAIFI decline[7], however factors unrelated to asset condition (such as weather impacts, tree impacts, and work impacts) can have impacts on reliability and have not been separated out from the data.[8]

A separate issue relates to the concerns that the $1.1 billion increase in sustaining capital projections[9] have only been raised now, following the completion of the Board's NFAT report.

[5] See PUB/MIPUG-14
[6] As shown on page 6 of Appendix 4.2
[7] Transcript 751 – 752 by Mr. Michel Morin
[8] Discussed on transcript pages 1532 – 1533 cross-examination between Mr. Antoine Hacault and Mr. Michel Morin
[9] From CEF12 to CEF14 for the next ten years, or a total investment approaching $5.7 billion from 2015 to 2024 as stated at page 11 of Hydro's Rebuttal Evidence, dated May 20, 2015.

ISSUE TOPIC #3: Vacancy Rate

ISSUE:

For the purpose of determining the level of rate increases required by Hydro in 2015/16, should the Board accept Hydro's forecast of O&M expenses, or should it assume a downward adjustment is needed to reflect the likelihood or appropriateness of a higher vacancy rate than Hydro has projected?

MIPUG RECOMMENDATION:

MIPUG recommends that the higher historic vacancy rates should be used to assess the reasonableness of Hydro's rate request. This is for 2 reasons: 1) the long-term average is likely to be representative of the most likely outcome for the current and future years, and 2) even if it is not, in an era of cost control (particularly cash), it would not be appropriate for Hydro to increase the pace with which it fills vacant positions, which is the basic underlying premise of a lower vacancy rate.

BACKGROUND AND POINTS IN SUPPORT:

In the 2012/14 GRA, Hydro projected 6.2% vacancy rate for 2012/13. MIPUG suggested it be adjusted to be more consistent with the 5 year actual average of 8%. The Board concluded that it expected Hydro to cap and reduce staffing levels and noted that it was part of the decision to give Hydro the award of only a 2.0% portion of the 3.5% increase proposed.[1]

For this GRA, the long-term vacancy rates continue to show variation around the 8% mark, as follows:

Vacancy Factor	2007/08	2008/09[2]	2009/10	2010/11	2011/12	2012/13	2013/14[3]	2014/15[4]
Actual	8.1%	7.2%	9.3%	7.4%	7.8%	8.5%	8.1%	5.5%
Forecast	5.2%	5.2%	6.6%	5.7%	6.3%	6.2%	5.5%	4.5%

[1] Board Order No. 43/13. April 26, 2013.
[2] 2007/08 and 2008/09 from MIPUG/MH I-29b in the 2012 GRA.
[3] 2009/10 to 2013/14 from MIPUG/MH I-6c
[4] Provided in MH-123

Hydro provided an actual amount for the 2014/15 year that is lower than past years, but this amount has not been properly reviewed or tested. In any event, one lower year does not in any material way alter the long-term averages, and would not appear to accord with what Hydro purports is an attempt to implement cost controls. Including this year of actuals into the long-term average adjusts the 8 year value down to approximately 7.7%.

Even though actuals are still above 7.7%, Hydro is proposing to use an vacancy rate of 4.5% per year for the IFF forecasts to calculate total OM&A salaries and wages (i.e., Hydro forecasts that an average of 4.5% of all positions are vacant in the forecast year).[5] Actual vacancy rates for the company have ranged between 7.2% and 9.3% per year[6] from 2007/08 to 2013/14. As an example, using the lower vacancy rate over the 6,468 total Equivalent Full-Time positions in the 2015/16 year[7] suggests that Hydro is forecasting approximately 291 EFTs will be vacant, while using recent actual vacancy rates would result in forecasts of between 479 to 601 vacant positions on average during the year.

The difference in assumptions has material impacts for Hydro's annual costs and income statement, and even greater impacts on cash, as shown in the Table from Exhibit MIPUG-14:

	2015/16	
Average Salary	$80,585	per Appendix 11.25
including benefits	$108,790	35% per Transcript 2470
Total EFTs	6468	Uses only straight time EFTs.
Hydro vacancy rate	4.50%	
vacant positions	291	
Long term average vacancy rate	8.20%	
vacant positions	530	
difference in assumptions	239	positions
cash impact	$26.0	million
capitalization percentage	39%	
income statement impact	$15.9	million

[5] MIPUG/MH I-6b.
[6] MIPUG/MH I-6c and MIPUG/MH I-29b from the 2012 GRA.
[7] Figure 5.5.8 from Appendix 5.5 to the Application, page 10.

Hydro has not provided a reasonable explanation for its forecast lower vacancy rate. In response to Coalition/MH II-16, Hydro states that vacancy rate is lower than experienced historically due to the need to fill vacant capital positions to support major new generation and transmission development; to replace aging utility assets; and to address increased capacity requirements (also Tr: 2182-2183). However, none of these factors is new or in any way unique to the IFF forecast years as compared to the 7 past years where the vacancy rate was near 8%. If anything, Hydro asserts it is in an era of increasing cost control, and vacancy management is a normal and expected part of such efforts.

PROS AND CONS OF ISSUE:

The benefit of adopting a staged overall rate increase that puts somewhat more pressure on cost control than Hydro has adopted is that there are numerous ways this type of pressure may serve to help control costs. Vacancy is a good example of where Hydro has considerable control over its costs. The only downside of adopting a lower rate increase in part in acknowledgement of (1) the likelihood of higher vacancies, or (b) pressure on Hydro to use all tools available to it, including vacancies, to control costs is that none of the available cost savings may come to pass. However, even if this were the case, slides 25 and 28 of Exhibit MIPUG-12 shows that Hydro remains highly cash flow positive for operations over the next decade, and adopting a somewhat lower rate increase for at least a few years has no conceivable prospect of changing that balance.

ISSUE TOPIC 4: Net Salvage

ISSUE:

Manitoba Hydro is proposing to eliminate the net salvage component of depreciation rates as a requirement of IFRS, though Hydro justifies the change as a purported benefit to ratepayers. Is the removal of net salvage appropriate for rate setting purposes?

MIPUG RECOMMENDATION:

MIPUG agrees with Manitoba Hydro that net salvage should be removed from annual depreciation costs and rates.

MIPUG recommends that this change occur because it is sound regulatory policy for rates and is not persuaded that it is in any way an offset that allows for a more aggressive method of depreciation to be implemented.

DISCUSSION AND SUPPORT:

Hydro is proposing to eliminate negative net salvage from collection in depreciation rates as it is no longer required under IFRS:

> Manitoba Hydro currently includes a provision in depreciation rates for asset removal costs. This is a regulatory practice applied under CGAAP by numerous Canadian Utilities. IFRS does not permit the practice of including a provision for the future removal costs of assets in deprecation unless there is a legal or constructive obligation to remove such assets. With the issuance of IFRS 14 Regulatory Deferral Accounts, Manitoba could continue to recognize this provision in depreciation rates as a regulatory deferral account. However, Manitoba Hydro has chosen to eliminate this practice upon its transition to IFRS in order to mitigate the impacts of other accounting changes to a net reduction in revenue requirement.[1]

Hydro has additionally stated that in their view, net salvage is being eliminated to offset the increase to ELG.[2] However, Hydro's position seems unclear as Mr. Rainkie also stated the view that:

[1] Appendix 5.6: 2014 Depreciation Study, page 5.
[2] Tr. 2145-2148

> I think Manitoba Hydro's already made provision by removing negative salvage, which we believe is – is a sound principle for rate setting. (Tr: 3750)

Regardless of Hydro's reasons for eliminating net salvage, the PUB should make a decision on whether or not the inclusion of net salvage is a principled and effective approach for ratemaking, as explained by Ms. Lee:

> MS. PATRICIA LEE: … Net salvage removal. The question is: Is Hydro doing this for the benefit of ratepayers, or because it's required? I heard two (2) different answers on this.
>
> At one (1) point I heard, Well, we're doing this because it will offset what we recognize as an increase in depreciation expense because of implementing ELG. On the same side, I heard, Well, we're doing this because IFRS requires it.
>
> If -- if it is a requirement of IFRS, that doesn't mean it has to be a requirement for regulatory purposes. I have always been a firm believer that regulatory does what regulatory needs to do for the benefit of the ratepayers, not because international accounting standards or federal accounting standards tell you, you have to.
>
> Companies where I am from, they keep -- maintain two (2) separate books. It is not a problem. Do they complain? Yes, they do, but then they do it, and it -- it's never been a problem. Telephone companies did it, electric companies are doing it. (Tr.3942)

There exists a concern that some the PUB's decisions, such as in relation to negative net salvage and deciding on a depreciation methodology are difficult because they may have different effects (rather positive or negative) and underlying arguments depending on the different areas of Hydro's operations, including generation, transmission and distribution.

> MR. PATRICK BOWMAN: And -- and in -- in my experience, if there's a principle reason to keep a net salvage, then you should keep it. If there's a pre -- if -- if there's not, then you should get rid of it. And it may be that the answer, in some cases, could be different between the utilities -- or between the -- sorry, not – between the utilities as well between the -- the functions within the utility.
>
> You're going to hear net salvage arguments from us that will tend to explain a generation perspective. That doesn't take away from a -- may --

> perhaps a distribution perspective that says, We do -- we do need to have a way to deal with disposals that's different than -- a net salvage that's different than the -- the generation part.
>
> So I -- I understand Hydro would look to have one (1) set of accounting policies. And if that's the case, then -- then you're bridging. You're having to find a way that you can deal with it that – that suits both, but it may be that -- that some compelling arguments on one (1) side only relate to part – one (1) part of the system, so. (Tr. 3867-3869)

Of the total decrease to depreciation expense forecast for 2015/16 from the removal of net salvage, $15.5 million is for generation, $4.2 million is for transmission, $19.4 million is for stations and $19.4 million is for distribution[3]. So while it may be appropriate to keep or make arrangements for future dismantlement costs for some asset categories, with respect to generation and transmission MIPUG believes net salvage should be removed from annual calculations as a sound regulatory principle:

> MR. PATRICK BOWMAN: … What -- where we disagree with Mr. Kennedy is whether it's appropriate for Manitoba Hydro today to keep in rates, and again my focus being primarily on generation and transmission.
>
> And this one -- this issue has had a lot of evolution over the past ten (10) years. I've been involved with it in a few different utilities, but it's important to recognize this account, that $530 million balance, only exists today on Hydro's books even under Canadian GAAP, never mind IFRS, because it – Hydro asserts that this Board wants it.
>
> It -- it says, In the past, I had my rate set if it was there, and the Board's never told me to get rid of it. So I'm going to call it a regulatory account. I'm going to say the Board wants me to have it.
>
> Now, I can't remember excerpt in an order where it says, Yeah, keep it. But -- but I also can't remember anyone saying, Get rid of it. I can't remember much discussion of it at all over all the time I've been here.
>
> But, nonetheless, it's in rates. It's - - it's built up this balance, and it only exists because Hydro will say to its auditors, this is a regulatory account. After IFRS, you -- you didn't even have that option unless you get the -- to deal with the specific exemption.

[3] MIPUG/MH-I-19a

But what I wanted to underline is that other utilities have moved in much the same direction as Hydro does going all the way back to 2004 or so when BC Hydro first stopped accruing to its net salvage reserve. It stopped putting into rates any more money to put aside funds for taking down things.

That was followed in Yukon, although in Yukon it was -- the Yukon Utilities Board hires the BCUC staff as advisors, so some of the same thinking came up to Yukon and they stopped putting aside amounts in rates.

And at the current time, in NWT, they've stopped putting aside amounts in rates. They haven't concluded whether they'll ever put it back, but they've stopped putting aside amounts in rates.

All of them have made their own decision about to do with balances a little bit different, but –- but, nonetheless, this has been a lively topic. It's moved for sure, and -- and it has to be debated on a principle. I think the package -- package deal argument about it doesn't -- doesn't hold water.

So at slide 41, we're talking about why would you get rid of the net salvage. Why is it not appropriate to keep it there? And, in short, I think the same type of principle decision that was made with respect to the other Crowns with respect to generation and transmission assets, I don't think this net salvage concept fits well, especially negative net salvage.

And the reason is, if you give yourself the concept of a test, this current generation of ratepayers is using the power from -- pick your plant -- Kelsey. Many years from now, Kelsey's going to need to be -- have an interim retirement.

The chances -- I think it's unlikely Kelsey will have a final retirement. You'll have an interim retirement. Means we take out the one that's there and put in a new one or we do it in parts over time. It's not a final retirement where we leave the site and do a greenfield. I think you've heard the same thing about Pointe du Bois.

So you're going to have an interim retirement. And the question is: In the year before the interim retirement, are the ratepayers of that day sitting there with a mess on their hands that they need to clean up because of the existing Kelsey? Or are they sitting there with a gem of an asset and a leg up on having a future Kelsey because the current one was there? Have you left them an economic value, or have you left them a mess?

> And the answer in hydro plants would tend to be, You left them a value. The answer on transmission lines, you've left them a right-of-way.
>
> There's a value. You have water licences. You have site development. You've already taken on the environmental costs. You've got infrastructures associated with the site. You've got communities who are used to dealing with this plant. You're not having to go through all the steps of putting in place. You leave a resource.
>
> And that's why -- I've even been involved in cases where very, very old hydro plants sell for a positive value. Not for a negative value, because you've got to consider the salvage, it's because for a positive value because of all of that -aspects of the -- of the resource. So when we're thinking about Kelsey today, Do we need to be building up a bank account to deal with a future Kelsey? No, the -- that is an advantage to people rather than having to build a new one later. So -- so if anything, rolling any of these costs into being recapitalized with a new plant makes total sense.
>
> There's also an excerpt in the IRs you'll see where the -- and I don't think this should be determinative, but IFRS comes to the same conclusion for a little bit of a different reason. And their conclusion, or the example they give is, if you were going to build an office building and you buy a piece of property that has a house on it.
>
> And you have to take down the – the cost of tearing down the house to add the office building, that would absolutely be a cost of building the office building. You would roll all that together as the -- your investment. There's no doubt that tearing down the house becomes part of the asset.
>
> So why is it any different if you owned the house and you didn't buy it outright from the beginning? The -- rolling the cost of removal in -- make -- would -- would lead to consistent treatment between those two (2) cases. And that -- I am afraid I don't have the reference down but that's in the – one of the excerpts that's in one of the IRs. And that's the end of the net salvage topic. (Tr. 3924-3929)

Additionally, Ms. Patricia Lee provided the following comments on inclusion of net salvage (T: 3941):

> The observation that utilities generally do not dismantle major generation sites upon retirement of the initial facilities, but rather re- purpose or retrofit the facilities. We've seen this specifically in Florida.

> We did set aside a reserve for what I call dismantlement of fossil fuel plants. What has happened since that time was companies are retrofitting. They are changing out the generation from steam, for example, to gas.
>
> They are building on the same site. You are not returning to greenfield. You are not totally dismantling. You will have interim retirements.
>
> And there's no guarantee that the money that's set aside for dismantlement will actually be used for dismantling. Why? Unless it is a funded reserve, it's nothing more than depreciation expense, which is internally generated funds and which can be used for anything from salary increases to any other option open to the company that is legal.

It is the position of MIPUG that in relation to net salvage, especially for generation and transmission which are expected to be replaced upon retirement with a new generation of assets that benefits from the pre-existence of the original assets, it makes sense for the Board to remove the net salvage provision from rates today.

This determination is also supported by the plans of Hydro for the future treatment of salvage costs upon retirement. Hydro's treatment of assets upon retirement is addressed in response to MIPUG/MH-II-26i-vii:

1. Asset removal costs will be charged against an asset retirement obligation where one exists for the asset being retired. To the extent that the costs to remove the asset from service are greater than or less than the amount in the obligation, a loss or gain for the difference will be charged to income in the period the expenditures are incurred. This treatment is consistent with Manitoba Hydro's existing treatment under CGAAP.

2. Asset removal costs will be recognized as part of the cost of the replacement asset when an asset is retired and replaced with a new asset.

3. Asset removal costs will be recognized immediately to net income in the year incurred where an asset is terminally retired (i.e. the retired asset is not replaced with a similar asset). This is expected to be a small minority of replacements.

ISSUE TOPIC 5: Equal Life Group Method

ISSUE:

Is ELG an appropriate depreciation method for the Board to adopt in determining just and reasonable rate levels?

MIPUG RECOMMENDATION:

MIPUG's recommendation is that the Board not approve Hydro's proposal to change to the ELG procedure for ratemaking purposes, but retain the Average Service Life (ASL) method. This method is appropriate for rate setting. It is used by basically every other regulated Crown utility in Canada.

If necessary to ensure proper and appropriate asset tracking, Hydro should add more component where a material number of value of items in a group have lives that differ materially from other items in the same group. This is appropriate whether using ELG or ASL.

DISCUSSION AND SUPPORT:

Manitoba Hydro is proposing to adopt the Equal Life Group (ELG) method for the depreciation of assets upon conversion to IFRS for the 2015/16 test year. This methodology change represents a departure from the long used and almost universal Average Service Life (ASL) methodology for depreciation. The change has material implications for rate payers.

MIPUG submits that the continued use of the longstanding ASL method is appropriate for depreciation of Hydro's assets for rate regulation because, among other things:

1) **Regulatory Precedent:** the ELG method is used by the vast majority of regulated North American utilities, particularly Canadian Crown utilities and hydro-based operations, and has been explicitly rejected by regulators in places such as Florida due to adverse rate impacts.
2) **Higher Cost, Less Equitable:** The ELG approach is higher cost than ASL. In theory this higher cost operates in exchange for lower costs in the future (a claim of intergenerational equity). However, this is not true for any utility that is growing like Manitoba Hydro. As specifically noted in the seminal NARUC Manual on Depreciation (Ex. PUB-22), in its culminating descriptive point on ELG, when plant is growing, the ELG rate will always exceed the ASL rate[1]. As a result, the benefit for future ratepayers of today's ratepayers having to pay higher rates is that they also have to pay higher rates. There is no crossover.

[1] In the NARUC manual the ASL rate is called the VG rate.

3) **ELG is not more precise:** Claims of ELG precision are linked to a theoretical construct of ELG that is not used in practice. The ELG method proposed by Manitoba Hydro contains many necessary simplifications in practice compared to the theory and textbooks, and as result the theoretical superiority claims are not justified. The ELG method is also dependent on very accurate data, good componentization and large enough groupings that the life estimates have statistical validity. Given a very poor data set for the retirements of many of Hydro's largest asset categories (as almost none have ever retired), Manitoba Hydro does not have sufficient estimates of the specific expected lives to successfully argue superiority of the ELG method. In contrast, Ms. Lee clarified that under these circumstances "…if it's precision that IFRS is requiring, it's my belief that average service life does it better than ELG." (Tr: 3998). Or as set out in the NARUC Manual on Depreciation:

> The ELG procedure is more sensitive than VG to retirement dispersion curves. Therefore, in order to calculate accurate depreciation accruals using the ELG procedure, detailed vintage plant mortality data must be maintained from which future mortality dispersion can be estimated. Without the long-term accumulation of data involving large numbers of units within each group, such accuracy may not be obtainable.[2]

Hydro first proposed changing to ELG in the 2012 GRA. At this time Hydro contended that it was required to implement for IFRS purposes, as Hydro's current ASL approach would not be acceptable to the auditors without further componentization. At the time Mr. Vince Warden commented that Hydro may not go to ELG if that became an option, as follows::

> "If rate regulated accounting were approved, or some form of rate regulated accounting by international board, then we would – at that point it would be a policy decision as to whether or not we wanted to continue to include net salvage value. We would also perhaps reconsider ELG as well."[3]

And further:

> "Mr. Peters, given the situation we have with IFRS at this particular time, there's some uncertainty as to whether or not we'll move to ELG. In the interim period we are still using ASL. And, if we proceed down this path

[2] Exhibit PUB-22, page 2.

[3] Transcript page from 2012/13 & 2013/14 General Rate Application 1650, reproduced in MIPUG-12, slide 56 of Direct Examination presentation of Patrick Bowman.

> and IFRS continues to be deferred, we will continue to use ASL. And if we take it to the next depreciation study in five (5) years from now, in fact, we will be adding more componentization in order for ASL rates to be compliant. So we may very well get there anyway, but it would probably not be a worthwhile exercise at this juncture."[4]

As the start date for IFRS was deferred during the course of the previous GRA hearing, the decision to switch to ELG was deferred until this GRA, with the PUB ordering Manitoba Hydro to file additional information to specific what, if any, increased componentization is required and at what cost, and to file an IFRS compliant ASL study for the next GRA.[5]

The evidence in this proceeding is different than the 2012 GRA where Hydro was addressing what was viewed as an immediate problem – the transition to IFRS and an inability to record regulatory assets and liabilities, compounded with insufficient time to address options. All 3 aspects do not apply today:

1) Hydro is transitioning to IFRS, however there is no obligation to complete such transition for the PUB reporting.
2) IFRS now permits recording of regulatory assets and liabilities, at least on an interim basis (in part based on the urging of regulators like CAMPUT who urged that regulatory decisions that were made in the interests of ratepayers should be reflected in financial statements, otherwise IFRS would be imposing a requirement for 2 sets of books that would be inefficient), and
3) There has now been additional time to address such matters as added componentization. Hydro testified that considerable work has been put into further asset data collection, yet no new components have been included in the depreciation study compared to the 2010 study (contrary to Hydro's CFO testimony in the 2012 GRA).

In short, both ASL and ELG are acceptable under IFRS, and ASL is vastly more accepted for regulatory purposes. Both are acceptable by auditors[6] and both methods provide full recovery over the period the related plant is in service.[7] The issue is in the timing of collection of depreciation - the relatively more aggressive ELG method being noted as appealing to regulators when depreciation shortfalls are persistent (which is not

[4] Transcript pages from 2012/13 & 2013/14 General Rate Application 1712-1713, and as shown in MIPUG-12, slide 56 of Direct Examination presentation of Patrick Bowman.
[5] Order 43/13 page 5 & 18.
[6] Stated by Ms. Sandy Bauerlein in response to question by Ms. Marilyn Kapitany on transcript page 3464
[7] Discussed at Transcript pages 3955 for ASL and 3953 for ELG.

the case for Hydro), and the less aggressive ASL method being used by regulators where Crown utilities are investing in very long lived assets.

Appendix 11.49: Componentized ASL Example

Hydro did not provide an IFRS-compliant ASL study that fulfills the PUB Directive from Order 43/13. Hydro's attempt at showing the effects of ASL and ELG in Appendix 11.49 was demonstrated to be a selective analysis, with questionable assumptions that specifically favour ELG, to conclude that the costs of ASL and ELG would be the same in the future. This is a fallacious conclusion. For example, Hydro analyzes the turbines and generators group under ELG (65 years) and ASL (divided 50:50 into 45 year assets and 75 year assets, which would have a 60 year average if combined instead of the 65 year average used for ELG)[8]. These are not comparable lives and the choice of lives favours the ELG method. In addition, although the life was shown as 50 years when broken out for the ELG example of Keeyask Generators (Account 1186G2), the ASL calculation uses a 45 year average life, also leading to higher depreciation estimates by comparison in that category.

Other examples of selective choices which may have skewed the extrapolation provided in this analysis include examples discussed by PUB Counsel with Mr. Larry Kennedy such as buildings, which represents about 3% of Hydro's total asset base, selected to show that component groups have very divergent asset characteristics[9], and Bipole III synchronous condensers, which represent 15% of Bipole III assets, chosen as it was thought it would have a disparate average service life (45 years compared to the grouped 65 year life). Meanwhile, metal towers, which represent 36% of the total Bipole III asset base but have a known lower ASL rate than ELG (1.16 vs. 1.23) and therefore would have lowered depreciation expense in this example, were not chosen for the extrapolation study provided in Appendix 11.49. [10]

Ms. Patricia Lee confirmed that Appendix 11.49 extrapolation study was not reliable and counter intuitive as ELG was a growing asset base will always lead to a higher depreciation expense.[11]

The Board should not put weight on this partial analysis which does not comply with the Directive given in Order 43/13 for an IFRS-compliant ASL study.

COMPONENTIZATION

[8] For example, Appendix 11.49 Attachment A page III-4.
[9] Discussed on transcript pages 3610 – 3614 between Mr. Sven Hombach and Mr. Larry Kennedy
[10] Discussed on transcript page 3618 - 3623 between Mr. Sven Hombach and Mr. Larry Kennedy
[11] Discussed by Ms. Patricia Lee and Mr. Patrick Bowman on transcript pages 3993 - 3996

Ms. Lee provided detailed and knowledgeable independent advice to the Board regarding the need for componentization.

> If you have an account, or a grouping where you have significant investment that is going to live different from the rest of the investment, then you as a company should be withdrawing that and treating it as a separate group.
>
> AND
>
> Whether or not you're using ELG, whether or not anything else, that's good business practice. That's good depreciation. You need to be separating those -- those pieces out. (Tr: 3946)

Hydro has asserted that their current level of componentization is sufficient if the ELG method is used, but is not sufficient if the ASL method is used. Hydro asserted that it would be time consuming and costly to further componentize and that there would be no benefit to ratepayers from this exercise, as with the ELG method such componentization is not required. This is not consistent with the advice of Ms. Lee:

> Componentization is the key. You need it regardless of what procedure you use, whether it's ASL or whether it's ELG. Componentization should come first, then the procedure. (Tr: 3959).

In short, there is no principled basis for suggesting that the required level of componentization is somehow linked to the group depreciation method. Further, Hydro has already indicated that it would continue to work on implementing componentization if and where it logically makes sense to do so (i.e. where account components have largely differing lives) and indeed was supposed to have completed that exercise before the current depreciation study was undertaken.

BENEFITS OF ASL FOR BRINGING ON NEW LONG LIVED ASSETS

For rate setting purposes, bringing large new assets into service can lead to adverse rate pressures for many years. This is inconsistent with the economic profile of the assets which typically grow in value over time (e.g., the value of energy output grows at least with inflation, as well as other factors such as environmental restrictions on alternatives) and with the fundamental regulatory concept of the asset being “used and useful” for ratepayers (where assets such as Keeyask will one day be largely serving domestic ratepayers, when it comes on line much if not all of the power is not used domestically).

As discussed in PUB/MIPUG-16 the following benefits of ASL exist that help address intergenerational issues:

- The upfront capital intensive nature of long-lived generation and transmission assets requires large upfront costs but minimal ongoing operating costs once in-service. Since costs are known upfront with low risk of large ongoing costs, there is little risk that future ratepayers will be 'stuck' with unknown expenditures by not collecting more in the earlier years, as occurs under ELG.
- A Crown-owned, hydro-electric utility, such as Hydro, should take a consistent and properly matched long-term approach to collection of depreciation which matches the use and usefulness of the assets. This is done by using ASL which charges the same depreciation rate in each year of the assets life.
- When a major generation or transmission asset comes in-service, as will be seen in the coming years with Bipole III and Keeyask, the costs to ratepayers are high. Finance expense, for example, is at the largest item in revenue requirement in the earliest years of a project[12].
- ASL remains industry standard and acceptable: As listed in MIPUG/PUB-17 and discussed by Mr. Bowman on transcript page 3930, "Manitoba Hydro using an ELG method as an outlier in Canada, from what we've seen every other Crown uses ASL, I've been involved with one (1) Crown which converted from ELG to ASL." And confirmed by Mr. Larry Kennedy on transcript pages 3590 – 3592.

- Further, when other large assets have been brought into service, such as Bipoles I and II, even methods such as ASL were viewed as too aggressive and instead a leaseback situation was arranged that had the equivalent of effectively zero or negative depreciation in the early years (Tr: 3880).

- ASL improves the transparency of methods, calculations, and resulting expenses for use in setting customer rates. The ELG rates can be counter intuitive, difficult to calculate, and difficult to decipher the underlying principles and mathematics. ASL has transparency of method which is important in rate regulation[13].

IMPLICATIONS OF ELG

[12] For example, the Wuskwatim Power Limited Partnership Projected Operating Statement for the first 15 years of the project as shown in Appendix 11.6. The costs to WPLP in the earlier years of operation are much larger than the revenues (with a negative net income of -$77 million) but by 2030 these costs have reduced largely due to reduced debt and net book values. At the same time, revenue is lower in the earlier years but grows over time for a positive forecast Net Income after the initial years of Wuskwatim operations.

[13] Discussed by Ms. Pat Lee, transcript pages 4000 - 4001

Implementing ELG will cause an increase to expenses of $36 million in the 2015/16 test year compared to ASL on a consistently componentized basis. There are no estimates of the costs of ELG and ASL in the event Hydro does complete its additional componentization, or the auditor requires further granularity, but both methods would be expected to be affected largely similarly.

This adverse impact will grow as Hydro's asset base continues to grow, forecast to increase by $69 million compared to the current ASL method by 2024[14]. The impact of ELG is more than just a short-term 'bump' in the immediate years of implementation of equal life group procedure in an aged utility[15].

Hydro also does not appear to have accounting policies that are consistent with ELG. Hydro's capitalization policies may not reflect required capitalization of some retirements of assets that the higher ELG rate is based on. For example, at transcript page 3439:

> MR. LARRY KENNEDY: ... So, for example, if we take all those poles that -- that Ms. Bauerlein was describing, we do know some components of the pole will have a different life, and we also know that not every pole will expire at the same time. There's, you know, cars hit poles, wind storms take poles down. Not all poles are expected, even the physical pole itself, to last the same -- over the same period.
>
> In fact, we -- we know for – for certain that there will be a dispersion in the retirement of those poles due to various forces of retirement. The equal life group procedure subdivides the investment in those poles over that expected dispersion of the retirement activity. So it's much more precise in its ability to -- to determine the amount of investment that will live over very specific periods, anywhere from age one (1) to -- to an age very -- very far out into the future and beyond the average service life. So it -- it includes very precise calculations for very many average service life estimates.

However, based on the response to MIPUG/MH-II-26i-vii, the replacement of a pole that was knocked down when hit by a car, for example, early in its life would be charged to income based on Hydro's criteria for capitalization. Mr. Bowman further discusses the concern that Hydro's policies do not match ELG retirement assumptions on transcript pages 4096 – 4098, where he references the testimony of Hydro witnesses at the previous GRA, as summarized on page 25 of Mr. Bowman's prefiled testimony:

[14] From PUB/MH I-73

[15] As stated by Mr. Larry Kennedy on transcript page 3512 as the argument against ELG in an aged utility.

> MR. RAYMOND LAFOND: But I think Manitoba Hydro capital -- for instance, a new pole which is replacing an old pole, does capitalize that rather than just call it maintenance, because it's repair -- it's -- it's simply replacing the same thing, correct?
>
> MR. VINCE WARDEN: It depends on – on the circumstances, but if -- if it's due to life expiry, then, yes, we would capitalize the replacement asset. If it was due to a -- a car again running into a pole, then it would be charged against maintenance. (Tr: 4585-4586, January 18, 2013)

Or as summarized by Mr. Bowman in the current hearing:

> MR. PATRICK BOWMAN: … [Y]our capital asset policies need to be consistent with your depreciation policies. If your capital asset accounting policies, your capitalization policies, are going to say, for example -- and it's a distribution example, but are going to say, For example if a distribution pole is hit by a car two (2) years old we're going to -- we're going to swap it out with another one from O&M and keep depreciating it as – as if it was -- you know, with -- without affecting our depreciation. If that's the way your capitalization policies are structured, then an ELG method, which takes your full suite of new poles and says, Some of those are going to last one (1) year and have to be fully amortized over one (1) year, and some of them are going to last two (2) years and have to be fully amortized over two (2) years, and slice -- makes all of your little slices, that premise that says some of them are going to last two (2) years and have to be fully amortized because at the end I'm going to dispose of it and capitalize a new one, is -- is wrong because you're not going to capitalize a new one. You're going to put it through O&M.

ISSUE TOPIC #6: Overhead Capitalization Accounting Policy Changes

ISSUE:

For rate-setting purposes, should the Board accept Hydro's proposal that the overhead capitalization rate used for rate-setting be materially reduced to expense more costs in the year incurred rather than capitalizing these costs?

MIPUG RECOMMENDATION:

MIPUG recommends that the Board reject Hydro's proposal, and have Hydro maintain, for rate setting purposes, capitalization policies consistent with those in place prior to IFRS implementation. This change increases Hydro's projected net income for the years in the IFF by approximately $60 million/year and is consistent with the longstanding interpretation of fair cost distribution used in Manitoba (i.e., the balance of costs that should be paid for today, versus those that are capitalized and paid for over the life of new capital plant).

By clarifying today that the Board expects Hydro to continue with existing capitalization approaches for rate setting, Hydro is provided options with how to reflect this Board decision in their IFRS statements (i.e., they can make the IFRS and regulatory statements consistent by using a permitted regulatory deferral, or they can reject to use a regulatory deferral and opt to produce separate IFRS statements as a "second set of books").

If for some reason the Board does not make this regulatory decision clear today, it is possible that only the latter IFRS option may be available for Hydro in future (i.e., IFRS may require Hydro to keep a second set of books).

DISCUSSION AND SUPPORT

The Board recognized in Order 43/13 (page 14-15) that Hydro had made changes to its overhead capitalization policies between 2008 and 2012 which brought far more costs into the current day expenses rather than being capitalized. At that time, the total changes were $57.6 million. In that Order, the Board accepted Hydro's proposed overhead accounting changes. However, the Board also noted it expected Hydro to not make any further accounting changes for rate-setting purposes.[1]

[1] Order 43/13. April 26, 2013, page 14 & 15.

In the current GRA, Hydro's total accounting changes related to capital overheads now totals approximately $120 million[2], or more than $60 million higher than the level when the Board indicated to make no further changes.

Factually, since the last GRA, in addition to raising the pressure on rates for this issue, Hydro has also been presented more options to avoid the pressures than previously existed. With the adoption of IFRS14, which gives Hydro the opportunity to retain the longstanding approaches rather than be forced into new methods for financial statements, Hydro could have elected to protect customers from this pressure and still retain one set of books. At a basic level, it is not apparent why Hydro dismisses this approach and seeks to burden ratepayers (and the income statement) more than is necessary.

The net impact of Hydro's proposed OM&A accounting policy changes on the required level of rates is large ($60 million/year is the size of the entire GRA rate increase for 2015/16). The change is also of limited or no apparent benefit to ratepayers and is not rooted in regulatory fairness. MIPUG considers that these OM&A accounting policy changes should not be automatically included in Hydro's regulatory accounting, just because Hydro adopts the changes for its financial reporting (particularly where options exist to not adopt these changes for financial reporting).

It is also important to note that this issue should be addressed clearly by the PUB today. This is because there is some uncertainty with respect to the IFRS14 window, and there may be an inability to go back on any decisions if the regulatory practice is not crystallized in Hydro's first year of IFRS reporting. Of course, no IFRS rules can preclude or prevent the Board from fulfilling its mandate under the Public Utilities Board Act (i.e., if the Board thinks an approach is fair it must implement that approach regardless as to the accounting implications). However in terms of timing:

1) **Stay with current approach now retains one set of books PLUS flexibility:** If the Board makes clear that for today it is retaining the longstanding regulatory practice (i.e., rejecting Hydro's proposal to expense more than the current approach allows), Hydro can keep largely this same accounting in its IFRS financial statements. If the Board in future elects to move towards capitalizing less and expensing more as Hydro now proposes, then that too can be reflecting in the IFRS statements in future and no flexibility has been lost for either regulatory or financial statement purposes.
2) **Adopt Hydro's approach now is higher cost for ratepayers, plus less flexible in future for PUB:** If the Board elects to adopt Hydro's proposals to

[2] PUB/MH-I-73a. Note that some of the amounts shown relate to pension and benefits. The $120 million is solely the components related to overheads.

> expense more costs rather than capitalize, even in part, or on an interim basis, then the flexibility in the future appears to be markedly reduced. For example, if the Board ultimately decided that the pre-IFRS approaches were the most fair, but did not make this determination until a future GRA, it appears unlikely Hydro could include the implications of this reversal in its IFRS statements under IFRS14 (as the practice would not be "continuing" a regulatory deferral).

For all of the above reasons, maintaining with the current approach to capitalization is appropriate and fair.

Manitoba Hydro rejected the approach of maintaining the established practice in place pre-IFRS as follows (per Mr. Rainkie):

> We can change -- we can capitalize every dollar, I suppose, if we wanted to go to the end of that spectrum. But does that change the underlying economics of what we're doing? Does that change the financial position of the Corporation? No. What it does, if we use that – some concoction of different accounting policies, is to reduce the cashflow to the Company. (Tr: 1772-1773)

Hydro's assertions have two fundamental flaws:

1) In respect of **cashflow**, during the next 10 years when Hydro faces the most ambitious capital development phase in decades, Hydro is still able to cash flow all of its ongoing operations, plus all interest payments on debt for assets in service, plus fund the entirety of its Sustain Capital program, even if it stays at the very high new levels in IFF14. As noted by Mr Bowman in respect of MIPUG-12 slide 25 (which is solely data from Hydro's IFF):

> And the green line, you can read this directly off the IFF cashflow statement, is the total cash generated in the year by operating activities. That means, all of the cash I take in the door from selling power less all of my operating costs, all of my interest payments on the assets in service, all of my water rentals, all of my taxes, all of my fuel bills, all of those things. I -- I can pay all of that, and leave a cash surplus which is over 400 million a year. In the previous IFF it had been a little lower in the -- the first couple of years. Now it's a little higher, but in the back end it's lower. I'm not borrowing to pay interest. This is no borrowing to do this. This is the top part of the cashflow statement, and we can pull up the IFF if you like and see the numbers. Solid green line, over 400

> million a year. What I've put against that is the normal capital spending.
>
> Remember we -- the target would be nice if I could fund my normal capital plus 20 percent, and the answer is, in this period you can't. Right. You can't because among the things that's hitting your cash is that during this period you're absorbing almost $300 million a year annual cash costs for Bipole, and almost $100 million a year negative annual cash costs for Keeyask. And that's why the green line dips. (Tr: 3898-3900).

2) In respect of the **income statement**, the coming decade is one of known and expected headwinds. Electing to adopt more stringent overhead accounting policies where options not only exist, but have been made even more easily accommodated since the last GRA, is imprudent. Hydro's quote that they do not support accounting changes that do not affect "the underlying economics of what we're doing"[3] is ironic, in that it is Hydro that is proposing to make the accounting changes so as to reflect a new $60 million per year on the income statement (despite options to not do this). The MIPUG Argument is for maintaining the pre-IFRS status quo.

This is not to say that the decisions of the accounting profession for IFRS standards are incorrect for the purpose they were adopted – they just are incorrect for the purposes of achieving regulatory fairness between today's ratepayers and future ratepayers who will actually use these new assets.

MIPUG's core recommendation is that the Board reject Hydro's proposal that IFRS-related OM&A accounting changes be simply adopted for regulatory purposes. The only notable downside to this approach is if for some reason in future, the new IFRS14 interim standard is not continued and the Board decides to continue with MIPUG's proposed approach in future GRAs – at that time Hydro would likely be forced into separate reporting results for IFRS and for the PUB. However, at best this should be viewed as a speculative and (if it arises) minor downside, as the issue of separate reporting for regulatory and IFRS purposes cannot be determinative to this Board's decisions. As noted by Ms. Lee based on her extensive experience working with a regulator:

> MS. MARILYN KAPITANY: Can I just ask - you say it's not a problem. Do you have any sense from the companies you've worked with of what the additional cost is of keeping that extra set of books for this purpose?

[3] Tr: 1772-1773

> MS. PATRICIA LEE: I certainly don't, ma'am. I can tell you that when I say it's not a problem, when our Commission has -- has dictated or has ordered that a regulator -- a regulated company do something that may differ from financial reporting, the company does not come back and say, No, we can't do it, or, No, it's going to cost us more money than it's worth.
>
> All I can tell you is this is done by many utilities in the States, and I have not heard any utility to come back to -- whether it's my commission, and I haven't heard from it from any other state, where a utility has come back and said, We just cannot do this. It is just too cost prohibitive to keep two (2) sets of books. (Tr: 3945-3946)

ADDITIONAL RELEVANT MATERIAL

Shown in the Table from PUB/MH-I-31c below, for the IFRS-related OM&A cost increase changes (shown as Administrative Overhead OM&A changes), the detail of the forecast impact based on IFF11-2 was $37 million in 2016 going to $43 million in 2024, peaking at $47 million in 2029. MH now forecasts this same group of ineligible administrative overhead costs to be $55 million in 2016 and grow to $60 million in 2024, peaking at $67 million in 2029.

From PUB/MH-II-44a-d Hydro states that while the cost categories have not significantly changed, construction activity has, driving a greater proportion of overhead costs that would have been allocated to capital now being expensed.

	Actual						Forecast - MH14														
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	378	397	412	463	481	486	542	552	557	571	585	601	607	619	631	644	657	669	683	697
CGAAP Changes																					
Intangible assets	5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6
Overhead Capitalized	5	9	29	29	60	61	62	63	63	64	65	65	66	66	68	69	71	72	73	75	76
Change in Pension & Benefits (e.g. Discount rate)	-	-	-	3	14	25	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Subtotal CGAAP Changes	10	13	33	37	78	91	94	95	95	96	97	97	98	99	100	102	103	105	106	108	109
IFRS Changes																					
Administrative Overhead	-	-	-	-	-	-	-	55	55	56	56	57	57	58	59	60	62	63	64	65	67
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Pension	-	-	-	-	-	-	-	0	3	3	3	3	3	3	4	4	4	4	4	4	4
Employee Benefits	-	-	-	-	-	-	-	(3)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Subtotal IFRS Changes	-	-	-	-	-	-	-	51	56	57	58	58	59	60	61	62	63	65	66	67	69
Total OM&A Accounting Changes	10	13	33	37	78	91	94	146	151	153	154	156	157	158	161	164	166	169	172	175	178
OM&A expense 'electric only' net of Accounting Changes	355	364	364	375	385	390	392	396	400	405	417	430	444	448	458	468	478	487	497	508	519
# of Customers	527 472	532 359	537 299	542 681	548 774	555 760	561 825	568 443	575 648	582 805	589 777	596 602	603 152	609 374	615 257	620 832	626 211	631 327	636 198	640 842	645 338
OM&A per customer (in dollars) net of Accounting Changes	672	684	678	692	701	701	698	697	695	694	707	721	736	736	745	753	763	772	782	792	804

	Actual						Forecast - MH12														
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OM&A expense 'electric only' (in millions of $)	364	378	397	412	455	471	544	556	567	590	601	617	639	653	667	681	696	727	741	757	775
CGAAP Changes																					
Intangible assets	5	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6
Overhead Capitalized	5	9	29	29	56	58	59	60	61	62	64	65	66	68	69	70	72	73	75	76	78
Change in Pension & Benefits (e.g. Discount rate)	-	-	-	3	8	10	5	5	5	5	5	6	6	6	6	6	6	6	6	6	6
Subtotal CGAAP Changes	10	13	33	37	69	72	68	70	71	72	74	75	77	78	80	81	83	84	86	88	89
IFRS Changes																					
DSM	-	-	-	-	-	-	23	22	21	20	19	18	17	17	17	17	17	16	14	14	15
Site Remediation	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6
Regulatory Costs	-	-	-	-	-	-	1	1	2	1	1	1	1	1	1	1	1	1	1	1	1
Pension	-	-	-	-	-	-	-	2	4	5	7	9	11	12	26	29	33	36	39	43	46
Employee Benefits	-	-	-	-	-	-	(3)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	-	-	-	-
Admin & General	-	-	-	-	-	-	37	38	38	39	40	41	41	42	42	43	44	45	46	47	47
Subtotal IFRS Changes	-	-	-	-	-	-	62	66	69	69	71	73	75	77	92	96	100	104	106	111	116
Total OM&A Accounting Changes	10	13	33	37	69	72	130	135	140	141	145	148	152	156	172	178	183	188	192	199	205

Table from PUB/MH-I-31c Showing IFRS Changes Between OM&A Expenses in MH12 and MH14 ($ Millions)

ISSUE TOPIC #7: Demand Side Management

ISSUE:

Following the Needs For and Alternatives To review, the PUB panel recommended the increase of DSM savings to around 1.5% annually (including codes and standards) as this level was considered both achievable and economic. In this rate application, there are concerns by Hydro regarding cash flow levels in this period of capital development. At the same time DSM spending has increased substantially in an effort to achieve the recommended target level of savings.

Are Hydro's DSM projections reasonable and are they treated properly for managing cash flow and for setting rates?

MIPUG RECOMMENDATION:

DSM is a valuable resource to the utility. DSM also provides the favourable characteristic of being scalable, such that at times like the present (cash flow constrained utility, with poor export market prices), DSM can be subjected to the same pacing and prioritization as is appropriate for all capital spending.

For DSM spending that does occur, amortization periods should reasonably match the expected useful like of the program, and not be capped at 10 years.

Also, MIPUG recommends that Hydro should retain responsibility for delivering industrial DSM programs.

DISCUSSION AND SUPPORT:

Unlike other sustaining capital, DSM has unique characteristics. First, it is highly scalable to adapt to cash flow priorities. Second, the spending not only affects capital outlays, but also revenues (adversely). Third, DSM can have very positive economics over the life of a given program (e.g., up to 30 years) but be heavily cash negative and revenue negative for lengthy periods at the time of the spending.

In the context of cash flow constraints and the need to pace and prioritize capital spending over the coming few years, DSM should be used as one tool to adjust to ongoing conditions.

MR. PATRICK BOWMAN: And the conclusion there is no different than I just said except that I also note that if we're only talking about managing cash, in the last bullet I note, there are some investments being made

> that may have long-term payoff, but -- for things like DSM, but you do have flexibility. It's one (1) of the very things that people sell peop -- sell as DSM is it's scalable. When it's time not to do it, when the markets aren't there, when your -- when your cash isn't there you can scale it back a bit. When the – when the markets are there and the returns are there you can scale it up.
>
> So if you want to benefit cash – if somebody was sitting here saying, Gosh, my cash is a real problem, DSM is one (1) place you could look. (Tr: 3905)

Hydro's economic evaluations of DSM programs primarily include consideration of metrics such as Total Resource Cost which ignore the effects of lost revenue. The DSM metrics that focus on lost revenue, such as RIM, or a properly comprehensive Program Administrator Cost type of test (focused on the total cost of DSM to the utility for each program, on a per kW.h basis, including the effects of lost revenues) should be prioritized. Even in conducting these tests, Hydro should remain cognizant that positive metrics can still mean higher cash outlays, negative impacts on revenues, and adverse revenue requirement impacts for many years.

Hydro amortizes DSM programs over 10 years. However the economic evaluations are performed using resource planning benefits that can extend up to 30 years. If DSM programs only provided 10 years or less of benefits, they would be of little value today (particularly energy benefits, which are not helpful for reliability reasons – capacity programs like Curtailable also have the reliability benefit that they bring). In amortizing DSM programs, the periods should not be capped at 10 years when the program benefits are expected to last longer, as follows:

> MR. PATRICK BOWMAN: … [T]here has been a significant increase in the DSM spending and amortization since the previous GRA, which is no surprise to anyone who was at the NFAT hearing. It's just to note that this is -- does have an adverse impact on cash, particularly given the low export revenues, to replace the lost domestic revenue. So if you get a person to stop using a kilowatt hour through a DSM program, that person saves the cost of 1 kilowatt hour. If they're an industrial customer, it's four (4) cents. If it's residential, it's closer to eight (8). Hydro loses that revenue, but it has a kilowatt back it can go sell in export markets, and it can make whatever it can make from it. If it's opportunity, it might be making between two (2) and three (3) cents.
>
> So not only have you spent money on the DSM program, but you've lost the -- the revenue. And those two (2) combined give you the cash impact

> in the year where the savings occurred and the program was run. Of course, that -- that savings value will change if that kilowatt hour can be sold for more as years go on. That's why it's an investment, right?
>
> The -- one (1) of the problems that arises is that DSM's values to show that it's worthwhile are done on the long-term marginal values, up to thirty (30) years depending on the type of DSM program, but the costs are amortized over ten (10).
>
> If the DSM's only giving you ten (10) years of savings, looking at the ten (10) years ahead of us and the -- the market values, it's -- it's really hard to justify a DSM program. You -- the -- the -- these -- these programs pay for themselves, particularly when you look at those marginal values in years 10 to 20. And so you -- you have to make your decision now about to what extent this can play a role in overall managing of cashflow. (Tr: 4023 – 4024)

Finally, MIPUG member presentations highlighted that the industrial-Hydro relationship is a unique and close working team. Any industrial DSM programs are benefitted by being structured to take advantage of this working relationship. Industries often share with Hydro considerable information about their operations which can be confidential, and the benefits of industrial DSM can relate as much to issues which are specific to the customer (e.g., helping manage the costs of connection or Curtailable service) which cannot be outsourced to any new government agency. Even if a new government agency is established, Hydro should maintain responsibility for industrial DSM.

ISSUE TOPIC 8: Curtailable Rate Program

ISSUE:

Manitoba Hydro requested final approval of proposed interim caps imposed on the Curtailable Rate Program (CRP) from the 2012/13 and 2013/14 General Rate Application per Order 43/13.

MIPUG RECOMMENDATION:

MIPUG's priority is ensuring that the value of participation in the CRP to customers is maintained. While Hydro asserts that this can only be achieved by way of finalizing the interim caps from the 2012 GRA, MIPUG recommends that the caps on the Curtailable Rate Program should not be finalized as Hydro requests but should be maintained at the levels last approved on a permanent basis, that is 100 MW for Option R and 230 MW for Option A. This level will allow for addition of a reasonable number of interested new customers to join without diluting the value to existing customers.

MIPUG has no recommendation regarding the elimination of Option C since Hydro asserts it has little to no value to Hydro.

Hydro should ensure that in evaluating the benefits of the CRP, long-term benefits in terms of DSM and resource planning, should be included (despite the program having only a one year contractual commitment) considering the program has been subscribed continuously for over 2 decades.

Hydro should also work with interested parties to further develop the program to find mutual benefit from other forms of interruptibility and demand response.

DISCUSSION AND SUPPORT:

The Hydro proposals in respect of the CRP cause no negative impact on any existing customers in the program. However, with the caps imposed on the program, no new customers are able to join. Few options exist for industrial customers to manage their bill impacts, and the CRP is one of the largest, with a few MIPUG members having expressed interest in joining the program now or in the future.

Part of the reason for capping the program is that Hydro does not see additional value in sustaining or growing the CRP. However, Hydro's evaluation of the program benefits does not include the long-term value in the CRP, and also offers very limited other rate-related options for industrial customers to help manage the impacts of higher rates on their loads.

BACKGROUND

The CRP program is valuable as a capacity saving program for Hydro in emergencies and for contingency reserve deployment obligations. For example, in the winter of 2013/14 Option R curtailable load was curtailed for 183 minutes on February 5th in response to an outage on the HVDC system. Approximately 153 MWh of CRP load was curtailed for that event.[1]

The CRP has a positive RIM of 1.4 and NPV of $32.2 million for the next 15 years from 2014/15 to 2028/29. The retrospective savings of CRP from 1989/90 to 2013/14 is around or over 150 MW with some years close to 190 MW. Hydro projects 146.2 MW annual capacity savings from the program for the forecast years, making up 23% of the total demand savings annually[2].

The value of the program was summarized as follows (at T. 2992):

> MR. ANTOINE HACAULT: So from 2014/'15 up to 2028/'29, Manitoba Hydro is projecting that it's going to have an annual capacity savings of somewhere in the range of 146.2 megawatts, correct, under that program?
>
> MR. LLOYD KUCZEK: That's correct.
>
> MR. ANTOINE HACAULT: And if we go a little bit further to the right, that translates to megawatts at generation of 160.9 megawatts, correct?
>
> MR. LLOYD KUCZEK: Correct.
>
> MR. ANTOINE HACAULT: And finally, if I understand this table correctly, on the issue of annual capacity savings, that program in and of itself represents 23 percent of all the capacity savings projected by Manitoba Hydro on an annual basis for all that time period.
>
> MR. LLOYD KUCZEK: Correct.

The program provides capacity supplies as well as energy-related benefits to Hydro, as explained by Mr. Cormie, in particular, Option E was designed to build in energy and the load can be curtailed for a significant period of time:

> MR. DAVID CORMIE: Right. The Option A and Option C were designed as pure capacity sup -- supplies. Option E was then to build in some

[1] MH-127
[2] Appendix 8.1 Power Smart Plan 2014-2017, Page 42, Appendix A.1 and Appendix B.1.

> energy behind that. And so you'll notice for the Option E curtailments that the length of the annual amount of curtailments goes up into the seven (7) to eight hundred (800) hour range. So we can curtail -- we can curtail the -- the load for a significant period of time.
>
> And we designed those to deal with the two (2) week cold snap in the winter. So you're in the middle of January. You're running short of energy. You need to curtail the industrial demand to help get through that, so you can -- you can reduce the demand of power on the system as opposed to responding to emergencies where you just need the capacity for a few minutes to get through the emergency and -- and there's very little energy behind it.
>
> So when you match the capacity with the energy, it's -- it's the most similar to looking like what combustion turbine would do. A combustion turbine, you can turn it on, leave it on for a two (2) -- two (2) week cold snap. It'll give you energy and capacity. (Tr. 1574-1575)

Hydro gives the rationale for capping Option A and R and eliminating Option C of the CRP in the response to MIPUG/MH I-29a, which states that an internal review has been undertaken with the conclusion that additional curtailable load in the form presently available under the CRP, under the current Contingency Reserve Sharing Agreement in MISO, would only add to the existing surplus capacity and would not generate additional short-term income or cost savings for Hydro. Mr. Cormie explained that with the current reduction of capacity market in MISO, the demand charges Hydro receiving from selling surplus capacity are only about 5 percent of the value paying to the customer. However, Mr. Cormie also noted that the short-term capacity market may come back in 4 or 5 years and at that time, Hydro would be able to recover the majority of the costs to have additional capacity and would attract new customers.

> MR. SVEN HOMBACH: Right. You were on the record earlier stating that the value of the CRP is now greatly diminished, but Manitoba Hydro indicated that there still is value.
>
> Can you just elaborate exactly on what the residual value of that program to Manitoba Hydro is?
>
> MR. DAVID CORMIE: There -- there's two (2) types of value. One is the ability to curtail load in emergencies, and there still is a capacity market in MISO but the demand charges that we're able to attract by selling our surplus capacity are only about 5 percent of the value that we're paying the customer for. So we're not recovering the full value.

> And when we set up the program many years ago, we knew that the short-term capacity market would ebb and flow in terms of value. Some years the capacity, we would make a lot of money. In some years, the -- like this year where we wouldn't make a lot of money, and -- and in fact we were getting essentially no value.
>
> But it took customers -- we took – it required customers to make a commitment. We needed to train them. We needed to get them involved in our processes, and -- and in emergencies they do bring value although they're --they're -- we're not getting the full payback in the opportunity markets -- in the -- in the short-term capacity markets.
>
> And so for that -- for that reason, and -- given that in the long run we feel that there is value, we -- we want to keep the customers that we have, but we don't believe that there's enough additional value to spend more to attract more customers into the program when the market is – is very soft.
>
> And, you know, we know that the MISO market is going through a capacity reduction because of the retirement of coal plants, and maybe in four (4) or five (5) years the short-term capacity market will come back. What we've indicated is that if -- if that does come back and we can recover the majority of our costs of having additional paper capacity, or pure capacity available to us, then at that time we would go and attract new customers.
>
> And but until we get to that point, we're -- we -- we think it's best just to wait for the market to rebound, and then if it -- and if it does then at that point if there are willing customers we could -- we could sign them up. But for now we don't want to sign up customers today that we know that is -- is -- it -- it just doesn't make economic – make economic sense.
>
> We're not capacity short from a system perspective, from a system planning. We -- we won't need system capacity till past 2030, so there's no need to contract for that now when -- when that need might be fifteen (15) or twenty (20) years away. (Tr. 3202-3203).

Mr. Turner explained MIPUG's concern regarding Hydro's proposal to reduce caps on the CRP:

> MIPUG also has concerns regarding Hydro's proposal to -- to reduce caps on the curtailable rate program. The curtailable rate program, as most of us know, was developed in the early 1990s through joint efforts of industry and Hydro, and supported by the PUB. The program provides

> capacity for the benefit of the system, helps with the reliability, and is one (1) of the few DSM options available to industrial customers in Manitoba.
>
> In order to participate in this program, companies such as Canexus and others have invested significant time -- significant time and attention to having the necessary equipment, procedures, and staff training in order to respond as required when a curtailment occurs. This investment is -- in time and resources has paid off for both the MIPUG members as well as for Manitoba Hydro and its customers.
>
> The merits of this program were even noted during the recent NFAT hearing, where the PUB recommended that DSM programming be increased and noted that the curtailable rate program had potential to result in additional capacity savings and merited further review.
>
> Given all this, Hydro's move to reduce caps on the availabil -- availability of option A and 'R' is surprising. It is MIPUG's view that Manitoba Hydro continues to undervalue the long-term benefits of the Curtailable Rate Program.
>
> MIPUG is concerned about the development and encourages the Board to assess whether the lower interim caps sought by Manitoba Hydro for the program are actually required. Members do not want to see the value of the program diminished, but also do not want to see this option taken away from new participants.

MIPUG's position that the Curtailable Rate Program should remain at the current levels (i.e. is based on the fact that Hydro's narrow timeline for reviewing the economics of CRP lowers the measured long-term value in the program.

As explained in Mr. Bowman's pre-filed testimony, to respond to major power supply changes within very short periods of time (i.e. less than 5 minutes), customers must make effort to get their operations and facilities ready. This can include making investments in capital assets and control systems, as well as in staff procedures and practice in implementing interruptions. Hydro reviews the potential benefits of the CRP only on a one-year basis, which is not consistent with the long-term costs that customers make to the program. [3]

As explained by Mr. Patrick Bowman on transcript pages 4031 – 4034:

[3] MIPUG-8, Page 32

> MR. PATRICK BOWMAN: … It would seem that there's room within the program to preserve value and have the caps at the level that was in place prior to the last GRA, which is Option A at two hundred and thirty (230), and Option R at 100 megawatts. And part of the reason I can come to that conclusion is that when you look at the assessment of curtailable, Hydro gives the curtailable load and the curtailable program insufficient credit for the fact that it's been there for over two (2) decades and that customers have been on it continuously, and that there have been a -- an ongoing load. This program is analyzed as if it provides value for one (1) year and then everyone goes away.
>
> So no long-term values are prescribed to the program. And the rationale is, Well, there's no long-term contract with the customer. Just -- take it like just like every other DSM program, if you don't have a long-term contract with a customer they're not going to use the LED lightbulb and throw it out, but you rely on the premise, accurately, that you – you have evid -- evidence that in all likelihood the customer will continue to be there. The same thing with industrial – with curtailable. And so in that manner the -- the value is -- is understated. And the other is that the curtailable load does provide a -- a very local regional benefit for things like transmission constraints, which are of increasing importance, acco - - according to Hydro's evidence.
>
> …
>
> And my conclusion looking at that is the hundred and eighty (180) and the fifty (50), the proposed lower levels have been concluded to be of value on the basis of an analysis that it insufficiently considers the benefits, because it looks at this one (1) year no ongoing aspect and it doesn't give it credit for -- with the Hydro system.
>
> If you were to put in those higher values you would say this program is actually more valuable than Hydro gives it credit for and you might find that you can sustain the credits that are there to these customers and still have room for some more to participate. And that -- and that -- that's the essence of the -- of the conclusion.

The reason for the zero capacity assessment of CRP, as stated by Mr. Kuczek at page 2993-2994 of the transcript, was because the programs are one year renewable contracts that the capacity could not be aggregated as other DSM programs. However, the program has been successfully in operation for over 20 years and Hydro's DSM actual capacity savings have

utilized almost 150 MW or more since 2003/04[4] and forecast anticipates almost 150 MW of use in every year[5]. There is no reasonable basis to conclude that all participating customers may drop off within one year. Another potential solution to capture more value of CRP without capping the program was discussed by Mr. Hacault and Mr. Kuczek, recognized as lengthening the term of the agreement from one year to a multiple year contract.

> MR. ANTOINE HACAULT: Thank you. Going back to the discussion we had about the zero capacity put -- with respect to the Curtailable Rate Program, part of the explanation I understood was that it was because they're one (1) year renewable contracts.
>
> Is that correct?
>
> MR. LLOYD KUCZEK: That was my understanding, yes.
>
> MR. ANTOINE HACAULT: Okay. This is the lawyer in me. It seems to me, you just change your contract to a multiple year contract and solve that problem.
>
> Have you guys had discussions about that?
>
> MR. LLOYD KUCZEK: Even this morning, I did with Mr. Miles, yes.
>
> MR. ANTOINE HACAULT: But those discussions have not yet materialized in contracts with a duration of more than one (1) year?
>
> MR. LLOYD KUCZEK: No. Actually, Mr. Miles and I were speaking this morning about the -- just some of the potential opportunities. And that was something that -- he said he had some discussions with Mr. Friesen about earlier, so it wasn't just this morning. They are talking about what -- you know, like, whether or not more can be done in terms of capturing value.
>
> MR. ANTOINE HACAULT: And lengthening the term of the agreement would be a way to achieve having more value for Manitoba Hydro out of that program, correct?
>
> MR. LLOYD KUCZEK: That's correct –
>
> MR. ANTOINE HACAULT: Okay.

[4] Appendix 8.1 Power Smart Plan – Appendix B.1
[5] Appendix 8.1 Power Smart Plan – Appendix A.1

> MR. LLOYD KUCZEK: -- potentially. You know, I'd leave that to Mr. Miles to figure out whether or not -- and how we can structure a contract so that he could capture that value. (Tr. 3006-3007)

Hydro also fails to conduct a more thorough consideration of whether in fact a contractual commitment is required in order for Hydro to have confidence that a curtailable load will still be present in 3 or 5 years or longer. Even without such contract, there is a reasonable basis for confidence for the purposes of resource planning (at least as much confidence as one can have in any other aspect of forecasting, such as the load forecast or the forecast of energy prices).

It is noted from Exhibit MH-45 that in response to the PUB Panel's Report on the Needs For and Alternatives To (NFAT) Review, the Minister responsible for Manitoba Hydro stated that:

> The NFAT review has also raised the unique needs of large industrial power users. In response we request that Manitoba Hydro advance measures such as curtailable rates and load displacement programs which meet the needs of large power users like manufacturers and resource industries that create jobs and grow our Province's economy.[6]

[6] Page 4 of Letter dated July 2, 2014 to Mr. Fraser and Mr. Thomson