SUBJECT: **Rate Impacts**

REFERENCE: **Page 1-5**

PREAMBLE:

On Page 1-5 Mr. Bowman states, "Over the next 20 years, industrial customers alone are likely to either pay $400 million to amortize the planning costs spent by Manitoba Hydro up until June 2014 (if the projects do not go ahead), or as much as $800 million to secure the full PDP."

QUESTION:

a) Please provide detailed calculations and information supporting the calculated amounts industrial customers are anticipating to pay.

ANSWER:

(a)

The approximations above regarding total impact for industrial customers (Top Consumers)[1] were calculated as follows:

Two separate calculations were performed. First, Plan 1 (All Gas) was compared to a scenario with no need to amortize planning costs, and second Plan 14 (PDP) was compared to Plan 1.

With respect to Plan 1 and the planning costs, this covers costs spent by Manitoba Hydro up until June 2014 (if the projects do not go ahead). The $400 million share for the Top Consumers was calculated from MIPUG/MH I-003c from the NFAT review, as approximately 25% (approximate percentage of GS Top Consumer Load as a total Manitoba Hydro load) of the total sunk costs of $1,577.4 million (excluding interest).

Second, to forecast the rate impacts for customers each year under Plan 14 (PDP), the average customer rate ($39,270/GW.h)[2] was grown by 3.95% per year starting in the

[1] Appendix C to the NFAT the 2012 Load Forecast, Page 7. Note: This includes all GSL >100kV and some of the GSL 30-100kV load.

[2] An approximate current average customer rate for 2013/14 was calculated at $39,270/GW.h as total adjusted revenue at April 2013 rates ($199,653,443) for the GSL>100kV class divided by the Forecast Data 2013/14 Total kWh (5,084,180,000 kWh). This data was taken from the 2012/13 and 2013/14 General Rate Application in response to MIPUG/MH I-20(b), which provided billing determinants for the Residential and General Service rate classes based on fiscal 2013/14 forecast data at April 1, 2012 rates, interim-approved September 1, 2012 rates (as per BO 117/12), and proposed April 1, 2013 rates at the time the IR was filed on October 3, 2012.

2014/15 year (as the revenues provided by Hydro already include the increase in the 2013/14 year). The same was done for Plan 1 (All Gas) with the average customer rate grown by 3.43% per year starting in 2014/15.

Deducting the difference in revenues for Plan 1 (All Gas) from Plan 14 (PDP) provides the difference in revenues per year. This amount was summed (not NPV) across 20 years with the result at approximately $435 million.

On this basis, It was concluded that Plan 1 (All Gas) results in approximately $400 million higher rates than a hypothetical situation with no planning costs over the next 20 years, and Plan 14 (PDP) has rates approximately $400 million higher than Plan 1 (All Gas),or a total of $800 million for Top Consumers. Table 1 below shows the Load Forecast amounts and approximate annual revenues for the Top Consumer class under Plan 14 (PDP), Plan 1 (All Gas) and the difference.

Table 1: General Service Top Consumers Approximate Revenue Difference Plan 14 (PDP) vs. Plan 1 (All Gas)

Fiscal Year	GS Top Consumers Load Forecast (GW.h)	GS Top Consumers Revenue under All Gas Plan ($)	GS Top Consumers Revenue under Plan 14 ($)	*Difference (Plan 14 less Plan 1) ($)*
2012				
2013	5,821	228,588,030	228,588,030	-
2014	6,214	252,390,881	253,659,790	*1,268,909*
2015	6,208	260,795,830	263,424,753	*2,628,923*
2016	6,228	270,610,139	274,712,215	*4,102,076*
2017	6,223	279,667,362	285,334,090	*5,666,728*
2018	6,338	294,605,428	302,085,993	*7,480,565*
2019	6,478	311,441,138	320,954,738	*9,513,600*
2020	6,448	320,631,796	332,087,379	*11,455,583*
2021	6,578	338,315,545	352,164,605	*13,849,061*
2022	6,688	355,771,269	372,196,765	*16,425,496*
2023	6,798	374,026,431	393,261,999	*19,235,569*
2024	6,898	392,546,263	414,809,321	*22,263,057*
2025	6,998	411,896,518	437,445,293	*25,548,776*
2026	7,098	432,112,373	461,222,302	*29,109,929*
2027	7,198	453,230,444	486,195,170	*32,964,726*
2028	7,298	475,288,838	512,421,272	*37,132,434*
2029	7,398	498,327,217	539,960,650	*41,633,433*
2030	7,498	522,386,857	568,876,134	*46,489,277*
2031	7,598	547,510,711	599,233,468	*51,722,757*
2032	7,698	573,743,478	631,101,442	*57,357,964*
Total		**7,593,886,548**	**8,029,735,411**	**435,848,862**

SUBJECT:

REFERENCE: **Page 3-1**

PREAMBLE:

Mr. Bowman indicates that "Hydro has provided a comprehensive and detailed presentation of the NFAT materials in support of their basic contention that the Preferred Development Plan ('PDP") is the best outcome for ratepayers and for Manitoba. This includes extensive analysis that in many places goes well beyond that provided by most utilities undertaking a resource planning exercise".

QUESTION:

a) Please identify those aspects of Manitoba Hydro's resource planning exercise which go "well beyond that provided by most utilities undertaking a resource planning exercise".

ANSWER:

(a)

There are a number of key aspects Mr. Bowman is referring to in the quoted section, with two being of particular note:

1) Full financial modeling; and

2) Fulfillment of the entire resource requirement.

Each of these is discussed below.

It is first important to note that in many jurisdictions, there are two processes that occur as part of acquiring new regulated energy resources: a first step that involves a more general "resource plan" and a second that involves a more detailed project-specific (or IPP-specific, etc.) review such as a "Certificate of Public Convenience and Necessity" (CPCN). Manitoba Hydro's NFAT in effect contains aspects of each process, which is a somewhat complicating factor. The items noted below relate to comparisons to both resource planning and to project specific reviews.

The first aspect of Hydro's filing that is more comprehensive than usual is the analysis of Hydro's plan in terms of Hydro's overall financial and rate forecasts. In Mr. Bowman's experience most Canadian utilities who undertake a major resource plan or project development proposal will provide the incremental economics and financial impacts associated with the plan, but will provide little to no detail regarding all of the other factors driving rates over a long horizon[1]. Manitoba Hydro's financial analysis in Chapter 11 contains the entire IFF forecast for the 50 year planning horizon, including a baseline projection of all impacts to rates not just those that arise incrementally as a result of the selected plan. While this underlying projection is not determinative to the plan to be selected, it is very useful context and information.

Second, Manitoba Hydro provides modelling based on a full complement of resources to meet the domestic need throughout the analytical horizon. This means that Keeyask, at 3,003 GW.h dependable energy[2], is not compared to the cost of acquiring 3,003 GW.h from alternative sources, but compared as part of a portfolio of resources to the entire development plan needed to meet all domestic loads and relevant export commitments. This is not entirely unique – most resource planning exercises will include some aspects of this (although over horizons that are often shorter than Manitoba Hydro's), but for a review focused also on project-specific approvals, this type of detail is unusual and beneficial.

[1](a) For example, the BC Hydro November 2013 Integrated Resource Plan at Chapter 6 references only "Differential Rate Impacts" of the existing plans, pages 6-149 - 6-155 (November 2013). [Accessed online February 18, 2014]: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0006-nov-2013-irp-chap-6.pdf
(b) The Newfoundland & Labrador Board of Commissioners of Public Utilities Report to Government reviewed the Muskrat Falls project and was predicated on only assessing the comparative "least cost supply of power to the Island interconnected Customers for the Period 2011-2067" without underlying reference to the overall level of rates, (March 30, 2012). [Accessed online February 18, 2014]: http://www.gov.nl.ca/lowerchurchillproject/muskrat_falls_pub_final_report.pdf
(c) Similarly, Yukon Energy's review of the Mayo B hydro project justification focuses only on the project's costs and benefits as described in the Yukon Energy Corporation's Application Regarding the Proposed Mayo Hydro Enhancement Project (Mayo B),Chapter 4.0: Project Justification, page 21 (December 10, 2009). [Accessed online February 18, 2014]: http://www.yukonenergy.ca/media/site_documents/933_Part%203%20Mayo%20B%20Application.pdf

[2] NFAT Business Case, Chapter 2: Manitoba Hydro's Preferred Development Plan Facilities, Page 4 (August 2013).

SUBJECT: **Rate Impacts**

REFERENCE: **Page 3-9**

PREAMBLE:

On page 3-9 Mr. Bowman states, “A common standard for new bulk power projects such as hydraulic generation is that adverse impacts on financials or rates from new developments should not exceed somewhere in the order of 3-7 years until the “cross-over” point of costs into benefits is reached, and should not be excessively costly during the time frame up to the cross-over.”

QUESTION:

a) Please provide all references and supporting documents for such a standard for hydro-electric generation.

b) Please identify which projects developed by comparable Canadian utilities have met this standard.

ANSWER:

(a) and (b)

There are two aspects underlying the statement in Mr. Bowman’s evidence:

- First there is the practical standard applied in developing power projects in Canada. An overview of a number of examples is provided in Table 1 below.
- Second there is the mathematical reality of NPV calculations, which are more heavily dependent on results in the early years than those in later years.

On the issue of mathematics, it is important to recognize that for a project to achieve a positive NPV over a reasonable horizon, it becomes difficult to recover from a deficit arising in the early years. For example, over a 50 year analytical horizon, over 40% of the NPV value arises in the first 10 years (for a 30 year horizon it is over 50% in the first 10 years). Using a 50 year horizon as is done by Hydro, each nominal $1 benefit in year 35 offsets less than 10 cents of adverse impacts in year 1. Practically, this means that unless a project has a massive windfall in the later years, it becomes very difficult to overcome any material scale of adverse impacts or deficits that last for 10 or more years.

With respect to convention or standards, the examples provided in Table 1 below are instructive. The table illustrates that projects that are expected to have reasonable recovery horizons in the range noted by Mr. Bowman's evidence, such as Site C (6 years), Snare Cascades (5 years) or Wuskwatim (5-8 years), can be proposed without the need for government-based mitigation measures[1]. For projects that cannot meet this standard, typically some form of government support is required. For example:

- The Mayo Dawson transmission line was expected to have an adverse effect for 5-10 years. This project received a special government financing arrangement (a flexible Government-financed loan) to permit a portion of interest costs in the early years of the project to be forgiven in order to mitigate this impact. The degree of forgiveness was only as necessary to prevent adverse impacts. In the end, the project savings were greater than anticipated and the flexible provisions were only required for 2-3 years.

- The Mayo B Project had a similar arrangement re: flexible financing, as well as grants from the Federal and Territorial governments. This project was economic without these measures, and had an expected cross-over point of 14 years absent the government support mechanisms, which led to the conclusion regarding the need for government support.

- The Muskrat Falls project in Labrador, developed by NALCOR, a Crown Corporation of Newfoundland and Labrador is proposed to be charged to ratepayers at a fixed price with escalators. This price is below the price that would prevail under a normal regulatory model in the early years (i.e., the price is less than the sum of depreciation expense and the cost of capital). As a result of this government support, the project cross-over is now expected to be 4 years. It is not known what the crossover point would have been absent the government support.

For reference, absent a form of government benefit sharing support for the NFAT Plans, under Hydro's current forecasts the rate cross-over for Conawapa (the substantive difference between Plan 14 (PDP) and Plan 4 (K19/Gas/250MW)) is projected at more

[1] Rate mitigation measures such as the Snare-Cascades deferral account can be used via a rate regulator without the need for government support.

than 20 years for the first time that rates would be lower than they would be without Conawapa, and more than 50 years for an NPV cross-over (Bowman evidence, Appendix C, Figure 17)[2].

Please refer to Table 1 below for projects' forecast "cross-over" period developed by comparable Canadian utilities. The projects cited are all of a similar nature – capital intensive developments intended to deliver (generate or transmit) low variable cost generation such as hydro.

[2] This is reduced to approximately 40 years if the exceptionally low 1.86% real discount rate is used per Bowman evidence Appendix C, Figure 30.

Table 1: Comparison of Canadian Utility Forecast Project Cross-Over Periods

Utilities	Project	Forecast Cross-Over Period	Source	
BC Hydro	Site C	The Site C portfolio (F2024 ISD) is forecast to have cumulative rate savings compared to the no Site C portfolio starting around F2030 (i.e. about **6 years** into its economic life of 70 years and physical life of over 100 years) as compared to a Clean Generation portfolio.	BC Hydro, 2013 IRP, Chapter 6, Figure 6-21, page 6-153	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0006-nov-2013-irp-chap-6.pdf
Yukon Energy Corporation	Mayo B	Mayo B annual costs would remain above the alternative (diesel generation) for about **14 years** (end of 2011 ISD to 2026) if there is no government contributions received. This extended impact was viewed as problematic, and as a result, government support was sought. With government contributions in the form of (1) grants and (2) flexible financing, the project was expected to provide positive impacts on rates compared to the alternative starting in **year 1** (2012).	YEC, An Energy Project Certificate and an Energy Operation Certificate regarding the proposed Mayo Hydro Enhancement Project, Figure 1, page 14	http://www.yukonenergy.ca/media/site_documents/933_Part%203%20Mayo%20B%20Application.pdf

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Utilities	**Project**	**Forecast Cross-Over Period**	**Source**	
Yukon Energy Corporation	Mayo Dawson	The Mayo Dawson Transmission Line Project was designed to deliver surplus hydro generation from the Mayo generating station to displace diesel generation in Dawson. The project was originally forecast to reach the "crossover point" within **5 to 10 years** of the Project's operation. With increases in fuel prices, the project become lower cost than diesel generation within **3 years** after it came into service. (2003 to 2005)	Yukon Energy Corporation 2005 Required Revenues and Related Matters proceeding. IR response MCMAHON-YEC-1-49	Not available online
Northwest Territories Power Corporation	Snare Cascades	In order to smooth the rate increases experienced by customers as a result of the Snare Cascades project, the differences between the full revenue requirement for the project and the annual variable savings from the project was collected in a deferral account for **5 years** (1996/97 to 2000/01) and this deferral account was repaid over the following 10 years.	PUB of Northwest Territories, Decision 13-2006, page 1	http://www.nwtpublicutilitiesboard.ca/pdf/13-2006%20DECISION.pdf

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Nalcor Energy	Muskrat Falls Project	Nalcor set a power purchase price for Newfoundland & Labrador Hydro (NLH) (on behalf of island ratepayers) calculated at approximately $76/MWh in 2010$, escalating by 2% per year annually thereafter. This price was structured to achieve certain ratepayer benefits while still facilitating project development and to avoid intergenerational equity by eliminating large rate increases in the early years of the project for slow escalations over a longer period of time, to be charged to NLH customers. The result of this pricing mechanism is a **4 year** period of higher costs for supply once the Muskrat generation is delivered to the Island Interconnected System (2017-2020 inclusive), followed by lower costs thereafter.	Nalcor's Submission to the Board with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, page 40 - 42 of 158 Also Exhibit 14 (Rev 1) from the PUB Review of the proposal.	http://www.pub.nf.ca/applications/MuskratFalls2011/files/submission/Nalcor-Submission-Nov10-11.pdf http://www.pub.nf.ca/applications/muskratfalls2011/files/exhibits/Exhibit14-Rev1.pdf
Manitoba Hydro	Wuskwatim Project	The Wuskwatim NFAT provided financial analysis under both high price and low price forecasts. The range of timelines until the crossover point was reached varied from **5 to 8 years**.	Submission to the Manitoba Clean Environment Commission: Needs for and Alternatives to the Wuskwatim Project, Chapter 7, Figure 7.4-7.6, page 10 of 13	Not available online.

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SUBJECT: **Load Forecast**

REFERENCE: **Pages 3-11, D - 12**

PREAMBLE:

"Industrial load forecasting in particular is notoriously difficult when there are a limited number of customers."

QUESTION:

a) Please comment on CAC witnesses Gotham and Simpson's comments regarding Manitoba Hydro's method for its forecast of Top Consumers that "there is no justification that this approach is superior to appropriately crafted regression modeling in terms of forecast accuracy…) (Gotham and Simpson, p. 7).

b) Does Mr. Bowman agree with Mr. Todd's assertion that Manitoba Hydro's forecast of Top Consumers has had a consistent upward bias on the order of 3% - 5% (Elanchus, p. 23)?

ANSWER:

(a)

CAC witnesses Drs. Simpson and Gotham indicate that "there is no justification" that Hydro's approach to industrial load forecasting is "superior to an appropriately crafted regression modelling in terms of forecast accuracy".

Mr. Bowman notes two specific comments on this excerpt:

1) **Agree that no justification has been provided:** On the specific quote, similar to Drs. Simpson and Gotham, Mr. Bowman has not seen any specific analysis or justification that Hydro's approach is in fact superior to a hypothetical "appropriately crafted regression modelling".

2) **However, it's unlikely hypothetical regression could in practice be developed:** On the principle underlying the quote, Mr. Bowman's view is that it is possible a fully developed regression model could in theory yield an industrial load forecast that may have better accuracy than Hydro's approach; however, it

is unlikely this hypothetical model relationship could ever be practically developed for Manitoba or readily tested.

An important aspect of the issues under consideration is differences in horizon – short-term forecasts versus long-term.

Underlying Mr. Bowman's observations is that the industrial load changes that are, or have the potential to be, material over the short-to-medium term (for example, 1 to 10 years) tend to relate to new projects, or to closures of existing projects. For example, the closure of one paper mill in Manitoba in recent years contributed to reduction of nearly 75% in the load for the Pulp/Paper class of customers from 2005/06 to 2011/12, which drove a decrease in the overall class of 10%[1]. It is unlikely any regression-based model would have fully identified this degree of load reduction any more than Hydro's *informed opinion* approach. Over the longer-term, other considerations arise.

One to Five Year Horizon

Comments cited by Drs. Simpson and Gotham, based on the work of Elenchus, take issue with load forecasts from the past 5 years that Elenchus concludes show Hydro has over-forecast industrial loads ("upward bias") by 5% for one-year-out forecasts. In the context of resource planning, dealing with critical horizons in the 10-30 year time frame[2], such differences are relatively trivial, as they relate to different forecasting methodologies and indicate little about the effectiveness of Hydro's methods over the long-term.

Five to Ten Year Horizon

Forecasting industrial load growth over the next approximately 5 -10 years with either regression based techniques or the informed opinion technique is typically problematic. Within this horizon, it is often possible to identify some of the major loads that are likely to be of concern, but not to have any reliable information about their likelihood.

Using just one example from public materials, it is clear that Canada is seeking opportunities to increase its exports of Alberta-sourced oil products. At least four major pipeline projects are presently being seriously explored, including Keystone XL, the

[1] See PUB/MH II-365.
[2] For example, critical comparison differences between plans 4 and 12 relate to the common advancement of Keeyask from 2022 to 2019; followed by two options - Conawapa for 2031 (Plan 12), versus CCGT in 2032, 2038, 2041 and 2045 (Plan 4).

Northern Gateway project, a Trans Mountain pipeline expansion, and the Energy East pipeline proposal. Only one of the projects would involve load in Manitoba (Energy East).

While documentation produced by the Canadian Association of Petroleum Producers (CAPP, the industry association representing oilsands producers) in June 2013 indicates all 4 projects could be required by 2025[3], other commentators have suggested only a subset of the projects would likely be developed over the next one to two decades.

Energy East materials indicate that the project would be significant – economic benefits for Manitoba totaling $1.8 billion in GDP (capital and operating), $616 million in taxes as well as employment[4]. It would also be a large consumer of power. The following materials are provided by Energy East:

http://www.energyeastpipeline.com/wp-content/uploads/2013/08/Energy-East-Pump-Stations.pdf

Based on this information, the project would have pumping stations at approximately 80 km intervals as it traverses the province (theoretically 5-6 stations in Manitoba based on the length of traverse). Loads are indicated to total 15 MW per station to as much as 25 MW at maximum pumping capacity, so likely on the order of 75 to 150 MW total for Manitoba in total. This could approximate somewhere on the order of a 20% increase in industrial load, or an aggregate of over 10 years worth of the hypothetical 100 GW.h/year Potential Large Industrial Load (PLIL) added in the load forecast by Hydro.

Similarly, Vale in Thompson has continued to implement the 2010 announcement of the impending closure of the Thompson smelter and refinery, which is understood to be included in the load forecast. However, the potential for a major new phase of expanded mining activity by Vale in Thompson by 2020 also remains under active review. As no commitments have been made to the new deposit, it is understood that the loads associated with this operation would not be included in Hydro's load forecast.

It is not clear that an econometric or regression-based model could adequately address the binary nature and the underlying economic conditions that would lead to the implementation or failure of these major projects. Informed opinion similarly is unable to easily deal with this uncertainty.

[3] http://www.capp.ca/getdoc.aspx?DocId=227308 at page iv.
[4] https://www.energyeastpipeline.com/wp-content/uploads/2013/09/Energy-East-Deloitte-Economic-Benefits-Report.pdf

Beyond 10 Years

Beyond 10 years, an econometric or regression model may provide a more refined approach to developing the load forecast than Hydro's current trend-based approach. Such an approach would seek to use indirect measures of electrical consumption to predict usage (such as GDP, or relevant input or product prices for major Manitoba commodities). There are issues that arise with regression models, however:

1) It would be necessary to determine the appropriate variables for the modelling. This could be extremely difficult, as the diverse nature of Manitoba's economy may require too many input variables (in contrast to, say, the Pacific Northwest or Quebec where aluminum production may be dominant, or BC with respect to forestry metrics). Hydro's response to PUB/MH II-457a, for example, shows industrial load changes as compared to Manitoba GDP growth, and there would appear to be no discernible relationship.

2) The input variables also need to be forecast over this period. To the extent such input variables as metal prices or oil prices may be input variables, the load forecast would not benefit to the extent that forecasts of these types of variables are as equally uncertain as any direct measure of loads.

Finally, it is not appropriate to compare Hydro's year-by-year forecasts of the PLIL approach against actuals to determine if this approach is accurate. It is well known that industrial loads tend to move in larger stepped increments and not as a steady equal annual growth rate. However, despite this fact, it is reasonable to portray the ongoing load growth using an equal annual PLIL approach over the long-term with an acknowledgement that the intent is not to precisely predict the load in any given year, but simply the range of reasonable longer-term trends.

(b)

No, at least as the load forecast affects horizons relevant for resource planning.

Elenchus' comments in this regard relate to Hydro's one-year out forecast of industrial load, looking only at a sample of 5 load forecasts. This is too small a sample over too short a timeframe to come to any useful conclusion regarding Hydro's load forecasting for resource planning.

As a point of comparison, consider the load forecast for each class for the year 2021/22, approximately the date when Hydro now says the next resource will be required.

- In the 2004/05 load forecast[5], Hydro forecast:
  - Basic Residential loads would be 6,940 GW.h as at 2021/22
  - GS Mass Market at 9,264 GW.h in 2021/22
  - GS Top Consumers (largely industrial) at 6,920 GW.h in 2021/22[6]
- In the 2012/13 load forecast, Hydro now expects:
  - Basic Residential loads would be 8,173 GW.h as at 2021/22, an increase of 1,233 GW.h. This totals 41% of the dependable Keeyask output[7] solely to serve residential growth that was completely unexpected as of 2004/05 (e.g., as of the date when Wuskwatim commitments were being made)
  - GS Mass Market at 9,756 GW.h an increase of 492 GW.h, or 16% of dependable Keeyask output.
  - GS Top Consumers (largely industrial) at 6,517 GW.h, a decrease of 403 GW.h, or -13% of dependable Keeyask output[8].

It is acknowledged that in the middle of that period (between 2004/05 and 2012/13) Hydro had a period where what appears to be an excessively optimistic view prevailed regarding industrial load (see for example PUB/MH II-465a). This has now moderated.

Elenchus' conclusion that Hydro industrial load forecasts are overstated, and that "the Top Consumer sales forecast appears to be a major source of forecast error"[9] is not borne out over the periods relevant for the analysis of resource planning.

[5] 2004/05 was selected as this was the first load forecast to fully incorporate Winnipeg Hydro loads into the Manitoba Hydro system.
[6] 2004/05 Load Forecast from CAC/MSOS/I-9(a) from the Application for General Rate Increases as approved conditionally in B.O. 101/04, page 10 and 23.
[7] Based on 3,003 GWh dependable energy for Keeyask from Appendix 4.2: Manitoba Hydro Supply and Demand Tables, as per System Firm Energy Demand and Dependable Resources (GWh) @ generation
[8] Appendix D from NFAT Review, page 7
[9] Elenchus NFAT Review: A Review of Manitoba Hydro's Load Forecast, page 24-25

SUBJECT: **Drought Costs**

REFERENCE: **Page 3-13**

PREAMBLE:

On page 3-13 Mr. Bowman states, "…the drought costs in [Table 1] are not net financial losses (true net financial losses are much lower).

QUESTION:

a) Please define "true net financial losses".

b) Are the compounding effects of interest included in "true net financial losses"? Why or why not?

ANSWER:

(a)

True net financial losses is meant to represent not just the adverse impact of a drought, but the accounting net loss that would occur in the drought year. For example, Hydro may have been forecasting that it would earn $125 million in net income in a year under normal water conditions as an addition to retained earnings[1], where as a drought would adversely impact this value by $200 million. In that example, the true net financial loss from the drought (i.e. the reduction to retained earnings), as Mr. Bowman was using the term, is $75 million, not $200 million[2].

As an additional example, under the $125 million expected net income case from above, if a moderately severe drought occurred that had a $100 million adverse impact, Hydro would still be having a positive net income in that year, and would still add to retained earnings. It would not be a true net draw on reserves.

(b)

Yes. When there are financial net losses from drought (which do not generally occur in the modeled scenarios except possibly in the worst droughts) then amounts borrowed to

[1] More accurately, under the mean financial outcome of all water conditions.

[2] MIPUG has reviewed this issue in past evidence, including the Pre-Filed Testimony of P. Bowman for the 2012/13 and 2013/14 General Rate Application, Section 2.2.5 The Role of Reserves, page 2-9 (November 16, 2012). Available here: http://www.pub.gov.mb.ca/exhibits/mh-gra-2012-13-14-rnd2/ie/mipug_2012_gra_evidence.pdf

address these net losses would compound over multi-year droughts and potentially add to future net losses. The effect is relatively small in relation to the main conclusions in this section.

For example, not including compound interest the net losses under REF-REF-REF conditions for Plan 4 is shown at approximately $1 billion in Table 2 of Mr. Bowman's evidence, page 3-13[3], but including compound interest this cost grows to approximately $1.2 billion over the 5 year period. This remains a relatively small percentage of Hydro's retained earnings at that date (2034/35) of $6.6 billion per Appendix 11.4.

[3] Note that page numbering may be problematic in the Pre-Filed Testimony of P. Bowman submission dated February 5, 2014 for Chapter 3.

SUBJECT: **Optionality**

REFERENCE: **Page 3-18 [the last page of section 3]**

PREAMBLE:

Mr. Bowman said on Page 3-18 – "Hydro attempts to address the concept of optionality and adaptation in PUB/MH-I-279, but this cursory analysis fails to give the concept the profile required as a key planning tool."

QUESTION:

a) Does Mr. Bowman have specific suggestions for additional optionality analysis in the context of this NFAT filing? Please explain.

ANSWER:

(a)

Mr. Bowman has two specific suggestions at this time

1) Hydro should address the EV calculation issues in Mr. Bowman's Appendix B.

2) For this analysis, Hydro should collapse Pathway #5, and incorporate the WPS sale agreement as a possible future event under Pathway #4 (unless that deal can be concluded in the very near-term and properly modeled prior to the NFAT hearing starting) The basis for this is that with time, it will be revealed whether the contract (or equivalent) can be concluded, and this can form part of the information base for a future decision under Pathway #4 but not under Pathway #3. This approach is likely more representative of the present conditions than the creation of a discrete Pathway #5 that does not represent a decision fully within the control of Manitoba Hydro or the Government of Manitoba (unlike the distinction between Pathways #1-4 which are decisions largely within local control).

One additional concept that is likely excessively complicated to model, but which would enhance the case for protecting Conawapa is based on the artificially constrained degree of decision points. For example, the response assumes that protecting Conawapa is a fixed commitment for four years, and the approach cannot likely easily assess a commitment to two years of Conawapa spending followed by a decision point as to whether to commit to the subsequent two years. Despite the difficulty of modelling this choice, it is likely that the EV of protecting a Conawapa 2026 scenario is lower cost/higher benefit than represented in the EV values reported.

SUBJECT: **Discount Rate**

REFERENCE: **Pages B-1 and B-2**

PREAMBLE:

Mr. Bowman states on Pages B-1 and B-2 – "…a discount rate can capture two different concepts: 1) The cost of money/capital: One approach to developing a discount rate is to focus on the cost of money. For example, most corporate environments will value future revenues or costs at a rate that represents what their capital (debt or equity) costs…." "… 2) The time preference for money: Discount rates do not always represent a specific identifiable cost of capital. The discount rate concept is much broader – it is a comprehensive concept of the time preference for money. It is a subjective concept that can be unique to each individual, firm, government and can even vary between different scenarios or investment opportunities."

QUESTION:

a) In the context of economic analysis where the objective is maximizing overall economic value, does Mr. Bowman agree that the discount rate should reflect the inter-temporal financial tradeoffs being made in liquid financial markets? Please elaborate.

ANSWER:

(a)

In general, Mr. Bowman does agree that one interpretation of the discount rate is that it should reflect the inter-temporal financial tradeoffs being made in liquid financial markets where these markets exist.

However, the range of exceptions is very large. For example, the quoted theory does not indicate who to maximize overall economic value to. In a regulatory setting, the questions of fairness and risk sharing between various interested parties (e.g., ratepayers, government finances, various customer classes) are critical items that cannot be ignored.

More importantly, for the purposes of a regulatory review of a resource plan, the above concept implies a single "correct" discount rate. A more robust approach that meets multiple objectives is to simply test conclusions against a range of discount rates to determine the robustness of the conclusions. This same approach was used by Manitoba Hydro in response to PUB/MH I-149a REVISED Figure 11.13. So long as a given conclusion is relatively robust (e.g., Plan 7 (SCGT/C26) being inferior to Plan 2 (K22/Gas)), the debates over the precisely correct discount rates are of much less significance.

SUBJECT: **Economic Analysis**

REFERENCE: **Pages B-3**

PREAMBLE:

Mr. Bowman states on Page B-3 – "…there can be a benefit to considering NPVs calculated over a horizon that is shorter than the full forecast scenarios (effectively applying a 100% discount rate to later periods). This approach can be a coarse tool to reflect either severe uncertainty with the results in the very long horizon, or to reflect practical limits on an individual's horizon of concern."

QUESTION:

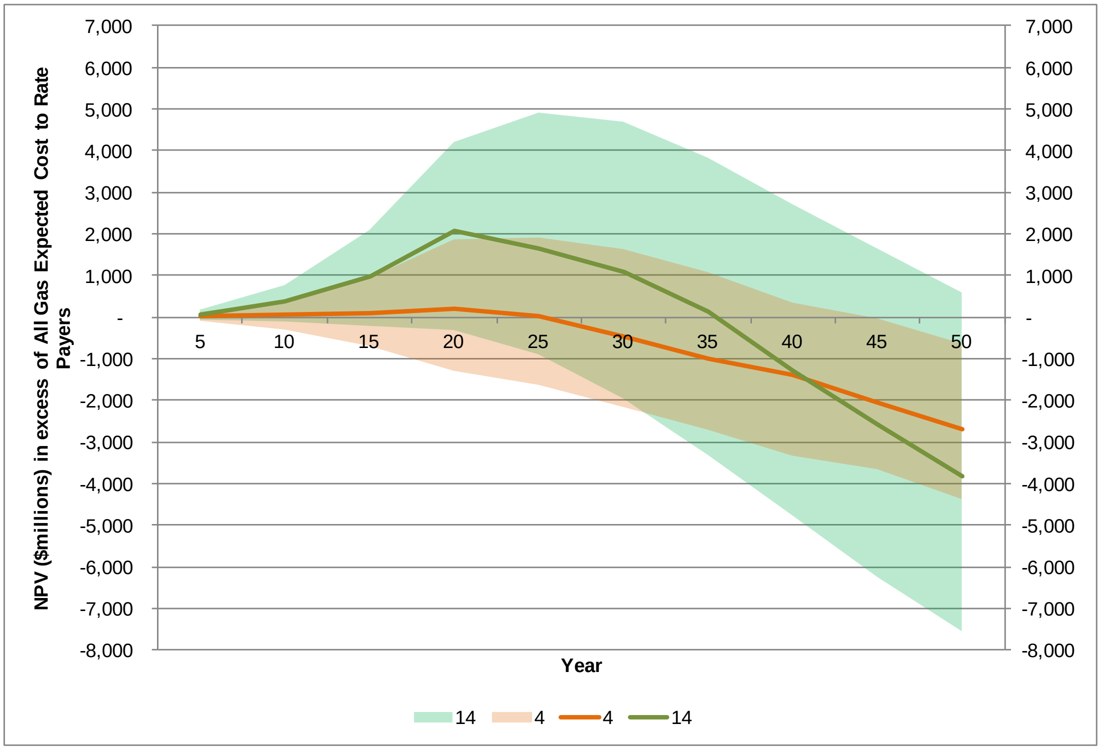
a) Mr. Bowman makes it clear that shortening the time horizon is akin to applying a 100% discount rate or, equivalently, assigning a zero value to long-run impacts with certainty. At the same time, he refers to the "severe uncertainty" in the long run. Does Mr. Bowman believe that truncating the time horizon is an effective way of dealing with long-run uncertainty? Please explain.

ANSWER:

(a)

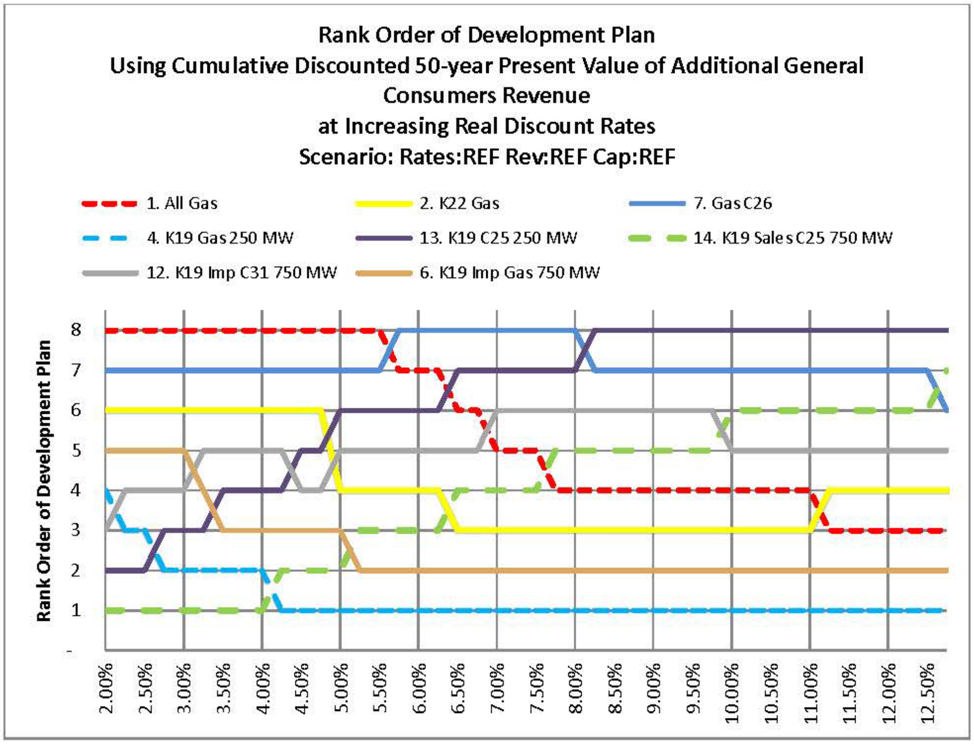
Not necessarily. But in a case such as that exhibited by Figure 30 in Appendix C of Mr. Bowman's Pre-Filed Testimony and Figure 11.13 of Hydro's response to PUB/MH I-149a REVISED (both reproduced below) it can be one of a suite of tools for understanding the relative impacts of Hydro's proposal.

Figure 30: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 1.86% Real Discount Rate-NPV of Incremental Domestic Ratepayer Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)[1]



[1] Pre-Filed Testimony of P. Bowman, Appendix C: Results of InterGroup Financial Analysis, page C-41 (February 5, 2014).

Figure 11.13 from PUB/MH I-149a REVISED[2]



In this case, Hydro has proposed use of an extremely, even excessively, low customer-focused risk-free discount rate of 1.86% real. The comparison of Plans 4 (K19/Gas/250MW) and 14 (PDP) in Figure 11.13 from Hydro's response shows that with this low rate[3], Plan 14 (PDP) is better than Plan 4 (K19/Gas/250MW). It is necessary to review Figure 30 in Appendix C of Mr. Bowman's evidence (reproduced above) to see this fully portrayed. In particular, this figure shows that at the 50 year horizon (the only point that is represented in Hydro's figure) Plan 14 (PDP), in green, is expected to be lower cumulative (NPV) cost to ratepayers (lower on the graph) than Plan 4 (K19/Gas/250MW), in orange[4]. However, over every horizon up to 40 years, Plan 14 (PDP) leads to a higher expected NPV level than Plan 4 (K19/Gas/250MW) and substantially higher upside risk (which represents higher costs to ratepayers).

Finally, it is important to note that Hydro's own submission effectively truncates the data stream no differently in that NFAT financial modelling terminates at 50 years while

[2] Page 6 of 26 of Response
[3] Hydro's response to PUB/MH I-149a proposes to uses 1.86% real discount rate, but their Figure 11.13 oddly does not include this range. It is necessarily to slightly extrapolate to the range below 2.00%, the lowest value on this figure.
[4] Note that Hydro's Figure 11.13 uses REF-REF-REF values while the Figure 30 from Appendix C of Mr. Bowman's evidence uses EV, the differences are immaterial for the above response.

economic modelling continues through year 78 (as well as having a small "Salvage value" which effectively incorporates impacts of an even longer horizon). Years 50-78 are relatively unimportant for much of the NFAT financial context, so this is a reasonable truncation. For many ratepayers, however, years 30-50, for example, may be equally unimportant to their possible perspectives on the NFAT proposals, so a shorter truncation approach is in effect no different in concept than that already in use in the NFAT filing.

Ultimately, one possible criticism of the NFAT proposals is that Hydro has simply taken much too long a horizon to seek benefits. Mr. Bowman has attempted to weigh this criticism using truncation approaches to see if the NFAT proposals still hold up over shorter time frames. This is a practical and reasonable, if somewhat simplified, approach to assessing, confirming or indeed dismissing such criticism.

SUBJECT: **Discount Rates and Interest Rates**

REFERENCE: **Page B-4, also see Page B-7**

PREAMBLE:

Mr. Bowman states on Page B-4 – “Can’t separate discount rate from real interest rates: Hydro has modeled the economics in a manner that can only reflect interest rates on debt through the discounting rate for present values. This means that there is no ability to independently test variations in discount rate within a desirable range.”

QUESTION:

a) For the purposes of economic analysis, does Mr. Bowman agree that discount rates and interest rates are inextricably linked? Please explain how discount rates and interest rates can be meaningfully de-linked in the context of economic analysis.

ANSWER:

(a)

Yes, but only in the broadest and most theoretical concept of interest. The underlying concepts are the same (valuing money over time).

However, interest rates in a market, as revealed individually and collectively by market interactions (the exchanges between borrowers and lenders), is a narrower concept. For the present purposes it is an overstatement to suggest that appropriate discount rates and market rates for interest are “inextricably linked”. A few examples of why this is the case:

- The practical concept of interest rates is typically linked to the concept of a commercial product for borrowing. Much of the economic framework for the NFAT cannot be readily matched up with a commercial product – for example, there are limited commercial borrowing markets for horizons that meet or exceed 50-78 years.

- As a commercial product for borrowing, interest rates can also be affected by a wide range of economic market failures, such as lack of liquidity or imperfect information.

- Interest rates inherently incorporate risk in pricing, but this risk can be materially different from the perspective of a lender than from the perspectives of the investor and public. For example, as noted in the introduction to "Discounting for Time and Risk in Energy Policy":

> Risk and how it should or should not be reflected in the discount rate is a part of all discussions of the discount rate for public as well as private investments. Recent developments in finance and economics have demonstrated that in many cases what is most relevant for determining the riskiness of an investment project is the covariance of its return with the returns to the economy as a whole and not the variance of its own return. This is true both from the standpoint of the nation as a whole and from the standpoint of individual investors, provided that they have access to fairly complete markets for risk, such as the securities markets. The discussions of the risks associated with new energy technologies have not always reflected this result. The development of an energy technology with very uncertain future returns may not constitute a risky project. If it will have a high payoff under just those conditions when the rest of the economy will do poorly, it will reduce the overall variability of national income and therefore reduce risk. Such an investment has the characteristics of insurance[1].

The above quote illustrates how a lender may focus their view of an investment on the variance of a project's returns, while a borrower (Hydro) and their stakeholders (including ratepayers, government finances, the Manitoba economy generally) may view risk through a more comprehensive lens that considers not just the effects of a given future on the project, but on other interacting aspects of the utility cost structure, or economy. Market interest rates may have difficulty fully resolving the risk of such an investment in a manner that provides an appropriate basis for developing a discount rate.

[1] Robert C. Lind, Kenneth J. Arrow, Gordon R. Corey, Partha Dasgupta, Amartya K. Sen, Thomas Stauffer, Joseph E. Stiglitz, J.A. Stockfisch and Robert Wilson. *Discounting for Time and Risk in Energy Policy*. Washington, D.C.: Resources for the Future, Inc.,1982. Pages 14-15.