REFERENCE: InterGroup Report, page 1-4 (lines 15-25)

PREAMBLE:

1) Focus on key decisions that need to be made today

The Board must provide recommendations regarding a set of near-term decisions regarding:

a. Whether to take up the Minnesota Power (MP) export agreement (including its requirement for Keeyask for 2019 which requires construction contract awards in the near term) [Whether to proceed with Pathways #1/2 or with Pathways #3/4/5]; and

b. If yes, whether to build the required new line at 750 MW or 250 MW [Whether to proceed with Pathway #3 versus Pathways #4/5].

All other decisions appear to be subsidiary to this immediate requirement. This is because all other aspects of the NFAT have longer and/or more flexible time horizons until commitment is required and/or are much less costly. The above two decisions, however, are not flexible to even short delays or future change.

QUESTION:

a) Does InterGroup agree that a third key decision that needs to be made today is whether or not to continue spending on Conawapa and, if so, whether to protect an in-service date as soon as the mid-2020s or perhaps not until the early 2030s?

ANSWER:

(a)

Mr. Bowman agrees that a decision needs to be made whether or not to continue protecting Conawapa for the 2018 decision date (needed to protect the earliest in-service date in the mid-2020s). However, this decision is not made in its entirety at a single point in time. It is an iterative process that only commits year-by-year (for example) to continuing to keep protecting the given in-service date and can be changed without severe repercussions (e.g., after 2 years, unlike, for example, a decision to proceed with Keeyask or to proceed with a 250 MW line instead of a 750 MW line which cannot be readily revised after 2 years).

Further, the financial costs involved in protecting Conawapa, at least for the next few years, are considerably smaller and shorter-term than the costs of the other near-term decisions required, such as the decision to actually build Keeyask.

REFERENCE: InterGroup Report, pages 1-5 to 1-7 and pages 3-4 to 3-11

PREAMBLE:

The report outlines two possible (competing) visions for the future – one based on Need and one based on Opportunity – and indicates that both are valid.

QUESTION:

a) What are the major factors/considerations that should go into the determination as to which vision should be adopted for Manitoba's power system?

b) Is it necessary to adopt one of the two visions or is some variation/hybrid of the two possible that involves a limited exploitation of "Opportunities"?

   i. If yes, what would be types of limiting factors/considerations that should be employed?

ANSWER:

(a)

The factors that should go into this decision are very broad, and go well beyond economics. Among the list of items to consider, in additional to traditional economic analysis:

1) Extent of benefits/costs/risks that arise outside of ratepayers economics (e.g., multiple account analysis in NFAT Chapter 13).

2) Extent of consistency with provincial Government policy and objectives (e.g., Clean Energy Strategy) and national Government policy and objectives (e.g., long-term commitments to reduce Greenhouse Gas Emissions)

3) Extent of consistency with long-term development planning for Manitoba (e.g., the consistent unfolding of the decisions made decades ago to focus future power development on the Nelson River).

4) General level of risk tolerance and economic resilience of the affected population.

However, the only decisions required today in the NFAT review are in regards to (i) Keeyask, (ii) the US Interconnection and (iii) to a certain extent whether or not to protect Conawapa.

(b)

Mr. Bowman's basic contention is that the first decision point is the distinction to focus only on Manitoba needs or to look outwards to opportunities (which encompasses many different scales of options that can be considered). The first decision (i.e., should Manitoba look outward at opportunities) can be made based on very broad considerations, including those listed in part (a).

If the selection is made to look outward at opportunities over Manitoba needs, then the decisions between the options available (i.e., what is the best way to pursue the opportunities) become more straight-forward and classic; primarily a comparison of rate impacts, risk levels, appropriate risk sharing and mitigation, and optionality.

There are also limiting factors. For example, one is that Hydro is not considering options that involve the utility becoming a majority shareholder in assets outside of Canada. Similarly no plans have been put forward to acquire assets that do not ultimately link to service provided in Manitoba (e.g., Hydro-Quebec at one time owned transmission assets in Chile – Manitoba Hydro is not proposing this type of investment). Further, it should be viewed as an absolute constraint that these types of plans should not be pursued unless there are clear benefits for the domestic ratepayers who are ultimately paying the costs and absorbing the risks.

It is noted that there could be additional constraints imposed on this second set of decisions – e.g., there could be a provincial policy decision constraint that says Hydro is free to pursue opportunities so long as it does not require the treasury to guarantee more than $10 billion in new debt. Such constraints have not been imposed, to Mr. Bowman's knowledge.

REFERENCE: InterGroup Report, page 1-6 (lines 4-6)

PREAMBLE:

Also of high value is that Plan 1 (All Gas) requires the least lead-time for decisions, which permits minimized commitments to be made in the current climate.

QUESTION:

a) The bullet appears to suggest that there are benefits to minimizing commitments to be made in the "current climate". Please explain what is meant by the "current climate" and why it is advantageous to minimize commitments in this context.

ANSWER:

(a)

The "current climate" in this bullet relates to a number of factors including:

1) **The uncertain conditions within the energy industry**. These are generally discussed in Manitoba Hydro's NFAT Business Case Chapter 3: Trends and Factors Influencing North American Electricity Supply and include:

- Recent developments in oil and gas extraction, including the growth of shale gas production leading to an uncertainty on future supply length and natural gas prices[1],
- Possible energy policy and climate change legislation[2],
- Declining rate of load growth post-recession in most North American economies[3],
- Historically low interest rates in Canada,
- Future technological advancement in DSM opportunities as well as alternative energy sources such as solar.

[1] NFAT Business Case, Chapter 3, page 30-33 of 41.
[2] NFAT Business Case, Chapter 3, page 9-10 of 41.
[3] NFAT Business Case, Chapter 3, page 3-4 of 41.

2) **The flexibility and time available for decisions of non-immediate resource options, such as Conawapa and gas.** Unlike past decisions, such as whether to proceed with Limestone, at this time the Preferred Development Plan is not "all or nothing" – there are options that only commit to portions of the required capital spending, or that avoid this decision for a period of time.

3) **The undetermined resolution for major sale agreements.** The unconfirmed sales contracts in this proceeding could underpin the commitment to Conawapa, including the WPS sale and potential additional arrangements such as SaskPower and the renewal of NSP contracts.

REFERENCE: InterGroup Report, page 1-7 (lines 8-9)

PREAMBLE:

Plan 4 (advance Keeyask to 2019, assume Natural Gas for 2024, build a 250 MW interconnection to Minnesota) which is part of Pathway #3, appears to be a better option for ratepayers than Plan 1 (All Gas)/Pathway #1, and is by far more preferable for most other interests (GHG emissions, First Nation investment, jobs, taxes, government revenues).

QUESTION:

a) Are there any “other interests” for whom Pathway #3 (Plan #4) is not preferable to Pathway #1 (Plan #1)?

ANSWER:

(a)

Likely there are “other interests” for whom Pathway #3 (Plan 4) is not preferable to Pathway #1 (Plan 1). For example, Pathway #1 typically involves lower capital cost commitments than Pathway #3. This generally equates to lower borrowing requirements. Contingents who are most affected or concerned about Manitoba’s gross level of borrowing would have a preference for Pathway #1.

Similarly, Pathway #1 requires no major resource commitments to be made for a number of years, and this period can be extended by aggressive (potentially overly-aggressive) pursuit of DSM. Contingents who either have an extremely high degree of skepticism with Hydro’s projections, or who are in a position to profit from excessive pursuit of DSM in Manitoba could benefit from Pathway #1.

Finally, Pathway #1 provides less Manitoba Hydro export power to the United States to fulfill supply needs, including renewable power mandates. Contingents who offer alternative power supplies to the US market may benefit from the reduced Manitoba Hydro contribution. For example, during the Wuskwatim NFAT hearing, US energy industry lobbyists[1] appeared to oppose the project.

[1] E.g., The Manitoba Clean Environment Commission Verbatim Transcript, Volume 8, Wuskwatim Generation and Transmission Project Hearing, pages 2144-2145 (March 16, 2004). [Available online here]; http://www.cecmanitoba.ca/resource/hearings/37/march1604.txt

The above comments do not address “other interests” which may be affected directly by the development of individual projects such as Keeyask or new US transmission. These interests are addressed as part of other processes (such as Environmental Assessment, the Clean Environment process, Adverse Effects mitigation negotiations, or Section 35 consultations).

REFERENCE: InterGroup Report, page 1-7 (lines 20-21)

PREAMBLE:

In Manitoba, the majority of adverse environmental and socio-economic impacts required to develop further Nelson River hydropower have already been experienced.

QUESTION:

a) What is the basis for the statement that "In Manitoba, the majority of the adverse environmental and socio-economic impacts required to develop further Nelson River hydropower have already been experienced"?

b) This statement appears to dismiss any incremental impacts that may occur and not acknowledge the issue of cumulative effects. Is it InterGroup's view that cumulative effects on local areas (either environmental or socio-economic) are not relevant?

ANSWER:

(a)

The basis for the statement is that substantial environmental and socio-economic impacts and costs associated with Lake Winnipeg Regulation and the Churchill River Diversion (LWR/CRD), and Bipoles I and II, have already been imposed. These projects cover by far the largest scale landscape and waterway changes required for further Nelson River development, and were undertaken in an era without current environmental standards for pre-project reviews or for impact mitigation.

This is not to minimize the potential impacts of individual future projects, which must all be appropriately assessed in light of any potential significant adverse impacts. However, the scale of landscape and waterway changes that would arise from these subsequent developments would generally be understood to be of a smaller magnitude than the original LWR/CRD developments.

(b)

Mr Bowman's view is that the Keeyask and Conawapa generating stations, as well any other potential Nelson River development, must be properly assessed for all potential significant adverse environmental and socio-economic impacts, including cumulative impacts, as required by legislation.

REFERENCE: **InterGroup Report, page 1-9, pages 3-4 to 3-5 and 4-10**

PREAMBLE:

QUESTION:

a) Other utilities (e.g. BC Hydro) consider rate design to be a DSM initiative. Would InterGroup consider rate designs aimed at achieving DSM to be within the scope of potential DSM initiatives that should be aggressively pursued (per pages 3-4 and 4-10) by Manitoba Hydro?

b) Please confirm that screening DSM using Levelized Utility Costs ("LUCs" - per page 3-4) does not take into account the incremental cost incurred directly by participating customers?

c) The Report (page 4-10, lines 18-20) calls for a departure from the current DSM screening approach that seeks "to ensure DSM measures (in combination, as part of a DSM plan) yield economic benefits to customers as well as Hydro". Does this mean that InterGroup's proposed screening approach could lead to the adoption of DSM measures (and/or an overall DSM plan) that do not yield economic benefits to customers overall (including both participating and non-participating customers)?

i. If not, please explain how the proposed screening measures ensure there are economic benefits to customers overall from DSM.

ii. If yes, why is this appropriate?

d) The InterGroup Report calls for the adoption of LUCs to screen DSM (page 3-4). It also calls for the use of the Program Administrator Cost (PAC) Test. Are these two tests equivalent and, if not, how do they differ? Furthermore, if they differ, which one is InterGroup suggesting should be adopted?

ANSWER:

(a)

In some cases Mr. Bowman considers that rate designs aimed at achieving DSM are within the scope of potential DSM initiatives that should be aggressively pursued. For example:

1) The Curtailable Rate Program offering by Hydro is a form of rate-based incentive to participating customers that is an extremely effective capacity based DSM resource.

2) Hydro has proposed a Time-of-Use industrial rate which has yet to be heard by the Board. While the details require appropriate review, a Time-of-Use rate, intended to incent a more efficient usage pattern and better cost tracking, could be part of a fully developed DSM program.

3) It is also possible that industrial self-generation could be compensated through a rate-based mechanism. At present, there is no such compensation offered in Hydro's system and as a result potential generation from waste streams (e.g., hydrogen, low grade heat, biomass waste) remains undeveloped.

In contrast, rate designs solely constructed to deter new load growth and development in Manitoba, such as the previous Energy Intensive Industrial Rate proposal ("EIIR") are ill advised, and should not be included as part of any DSM program.

(b) and (c)

Mr. Bowman confirms that screening DSM using LUCs does not take into account the incremental cost incurred with respect to participating customers. This is precisely the point, as it has been debated in the DSM literature[1]. In common language, Mr. Bowman's basic assertion is that Hydro should be prepared to pursue DSM initiatives that provide cost effective power resources to the utility. It should not reject DSM programs that customers may in fact participate in, solely because Hydro determines there is insufficient economic benefit to the customer.

The basic premise is that customers will often undertake actions which serve to both reduce their energy consumption and in theory yield the customer some form of benefits. However these "customer benefits" may not be financial in nature, may be very difficult to measure and may be different for individual customers. Often customers will pursue actions that would appear analytically to be economically irrational.

For the utility there are basically two choices:

[1] For example, see Chris Neme and Marty Kushler. "Is it Time to Ditch the TRC? Examining Concerns with Current Practice in Benefit-Cost Analysis." ACEEE Summary Study on Energy Efficiency in Buildings. 2010. [Available online here]: http://energy.maryland.gov/empower3/documents/ACEEEreferencestudy-NemeandKushlerSS10_Panel5_Paper06.pdf

1) Intensely analyze the customer's motivations, their economic payback, what other benefits they may be getting (such as better comfort (insulation), or more features (new refrigerator) as well as more obscure concepts such as social status and altruism). Then, assess (and at times reject) programs because the utility has determined there is not enough benefit for the customer.

2) Focus on the known utility economics. Permit the customer to make their own assessments and decisions.

A good example (outside of power utilities) of the two approaches may involve initiatives a number of years ago to improve market penetration of hybrid vehicles. There was a general desire among governments to have greater adoption of hybrid vehicles, but the costs and barriers regarding new technologies were problematic. Governments at times offered modest grants to qualified purchasers, which were far insufficient to offset the premium costs charged for the hybrid vehicle over the equivalent standard model. In many cases, customers purchased these vehicles despite the decision appearing economically inefficient – the customer would not have seen a positive return on their extra investment. It is not always clear why the customer made this decision, but aspects of stewardship, altruism and status are all possibilities. The government programs generally worked. Hybrids remain available and a relatively common vehicle offering despite the fact that the grants have largely ended.

Based on the types of tests applied in many traditional utility DSM analyses, the program of grants toward hybrid vehicles would have likely been rejected as it would have been concluded that they did not offer sufficient benefits to the customers. If a similar concept for a DSM program were available to the utility with these characteristics:

a) utility to offer modest support for energy efficient technologies;

b) the adoption of a program can offer up substantial energy consumption savings to the utility;

c) the total cost to the utility is competitive with other resources; and

d) the customers will adopt the technology as a result of the utility support, regardless as to whether this may appear economically irrational for the customer;

then it would be unfortunate for such programs to be rejected based simply on failing the TRC test, or a difficult to measure Societal Cost test.

With respect to non-participating customers, see part (d) below.

(d)

As described in Mr. Dunsky's response to MIPUG/CAC&GAC 4(b) in the Manitoba Hydro 2012/13 and 2013/14 GRA: "the LUC is not and should never be considered a "test", because it does not compare costs to benefits. It is rather a cost metric."

The PACT is the concept of the "test" for a particular program that is linked to the same rationale as the LUC. Again as noted by Mr. Dunsky in MIPUG/CAC&GAC I-4(b) from the Hydro 2012/13 and 2013/2014 GRA:

> As the question suggests, however, the LUC is a critically important metric, in that it subsequently allows us to compare costs (LUC = the unit cost) with benefits (e.g. avoided costs). The test that compares these is known as the Program Administrator Cost Test, or PACT (formerly known as the Utility Cost Test).

In regard to Mr. Bowman's submission, there are basically two scales of DSM that should be relevant to Manitoba Hydro:

1) **Resource Planning Comparisons:** When in a mode of resource acquisition, such as the present NFAT, DSM resources can be an alternative to new generation. However, DSM resources do not have a perfectly equivalent financial impact to acquiring new generation due to the impacts on utility revenues from reduced sales. Nonetheless, LUC based screening and a PACT is a reasonable test for the purposes of comparing among DSM program options.

    a. For example, in Appendix E (Hydro's 2013-2016 Power Smart Plan) page 41 shows that the LUC for the Industrial Performance Optimization Program is 1.5 cents/kW.h[2]. This is the largest single long-term DSM program Hydro offers[3]. When combined with the revenue loss associated with this power (approximately 3.9 cents/kW.h)[4] this means the power is acquired at 5.4 cents/kW.h net cost to Hydro. This compares favorably

[2] Appendix E: 2013 – 2016 Power Smart Plan, page 41
[3] Appendix E 2013 - 2016 Power Smart Plan, Appendix A.2
[4] See MH/MIPUG I-1 where this average cost of energy for the GSL>100kV class is calculated.

with Hydro's main other resource options (such as Keeyask at 6.0 cents/kW.h; Conawapa at 6.7 cents/kW.h and gas at 7.5-9.7 cents/kW.h)[5]. These values would suggest there may remain further room for somewhat more activity under the Performance Optimization program by adding in measures that may be slightly less beneficial than those already included, without undermining the viability of the initiative.

b. By comparison, the commercial building envelope programs (windows and insulation) at 2.4-2.5 cents/kW.h LUC[6] if applied to GS Small customers (with an average rate of 7.3 cents/kW.h[7]) would show total cost to acquire the power at upwards of 10 cents/kW.h. This is a more challenging DSM program, but remains potentially favourable if there are other characteristics that are beneficial to Hydro's costs (e.g., benefits to avoiding distribution system expansion, or if the loads to be saved are higher cost than average as they are concentrated in winter or in daytime hours).

Note that in the assessments above, there is no analysis of the customer's investment. For example, it may be that the customer is investing $100 for every $10 of energy saved – but this may still be beneficial for the customer due to improved comfort, or more stylish architectural details, etc. The economics of the customer's decision should be left to the customer.

2) **Assessment Under Normal Ongoing Operations:** When assessing DSM portfolios under normal circumstances outside of an NFAT resource acquisition phase, the level of DSM should also be guided by use of the Rate Impact Measure (RIM) test. The RIM test is a measure of the full financial impacts on the utility (costs incurred plus lost domestic revenue) as compared to the benefits (avoided investment or export revenues). At its core, the RIM test is measuring whether one group of customers is being made to pay excessive amounts to secure savings for a different group of customers, a blatant cross-subsidization. The key principle was outlined in comments made by Stan Wise, a former

[5] NFAT Chapter 7 Tables 7.3 and 7.4.
[6] Appendix E 2013-2016 Power Smart Plan, page 41
[7] An approximate current average customer rate for 2013/14 was calculated at $73,210/GW.h as total adjusted revenue at April 2013 rates ($134,563,726 and $136,076,017) for GS-ND and GS-D class respectively, divided by the Forecast Data 2013/14 Total kWh (1,632,178,221 kW.h and 2,064,602,134 kW.h). 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.

Chairman of the National Association of Regulatory Utility Commissioners (NARUC):

> When a DSM program fails the RIM test it means that customers who do not participate in a DSM program will be forced to subsidize customers who participate in the DSM program. Using an example of additional attic insulation as a DSM program, some reasons why customers may not participate in the DSM program include: 1) some low income customers can't afford to participate if they have to pay a portion of the cost of the attic insulation (even if the utility pays a rebate equal to 75% of the cost of the attic insulation the customer may not be able to afford the other 25%), 2) some customers may have paid the full cost of additional attic insulation prior to the inception of the DSM program so they cannot take advantage of the DSM program yet are forced to pay higher rates so that those who have not taken such action can add attic insulation in the future at a fraction of the cost in which this customer added their own attic insulation, 3) a customer may realize that they will be moving within the next few years and that they will not get a payback on any out of pocket costs associated with adding attic insulation to the house they will soon be selling (the amount of attic insulation is not a primary consideration for most people shopping for homes and therefore they generally won't pay any extra to the seller for additional attic insulation), 4) the customer may simply choose to not take any action because of a busy life or prioritizing other activities ahead of calling the utility to register for the program and then taking a day of vacation to meet an attic insulation contractor at their home on the day of the installation. When a DSM program fails the RIM test, customers who cannot or choose not to participate in the DSM program subsidize other customers who do participate in DSM programs, regardless of the reason for not participating in the DSM program[8].

[8] Presentation to the Southeast Energy Efficiency Meeting (part of the Regional Implementation Meetings of the Clean Energy Program of the US EPA), September 28, 2007 by Stan Wise, Commissioner of the Georgia Public Service Commission. http://www.epa.gov/cleanenergy/documents/suca/se-sep-07_wise.pdf

Overall, the principles are the same – Hydro should be seeking to secure power resources that are economic for the utility and its customers (including those that do not participate) and should not be rejected viable options because Hydro has second guessed the customer's motivations.

REFERENCE: **InterGroup Report, pages 1-10, page 3-7 and page D-3**

PREAMBLE:

At page 1-10, InterGroup concludes that "Hydro's approach to modelling DSM savings, as an adjustment to the load forecast rather than a competing resource, is appropriate for this NFAT". However, at pages 3-7 (lines 20-33) and D-3, the Report sets out various circumstances under which full testing as a competing resource could lead to different results.

QUESTION:

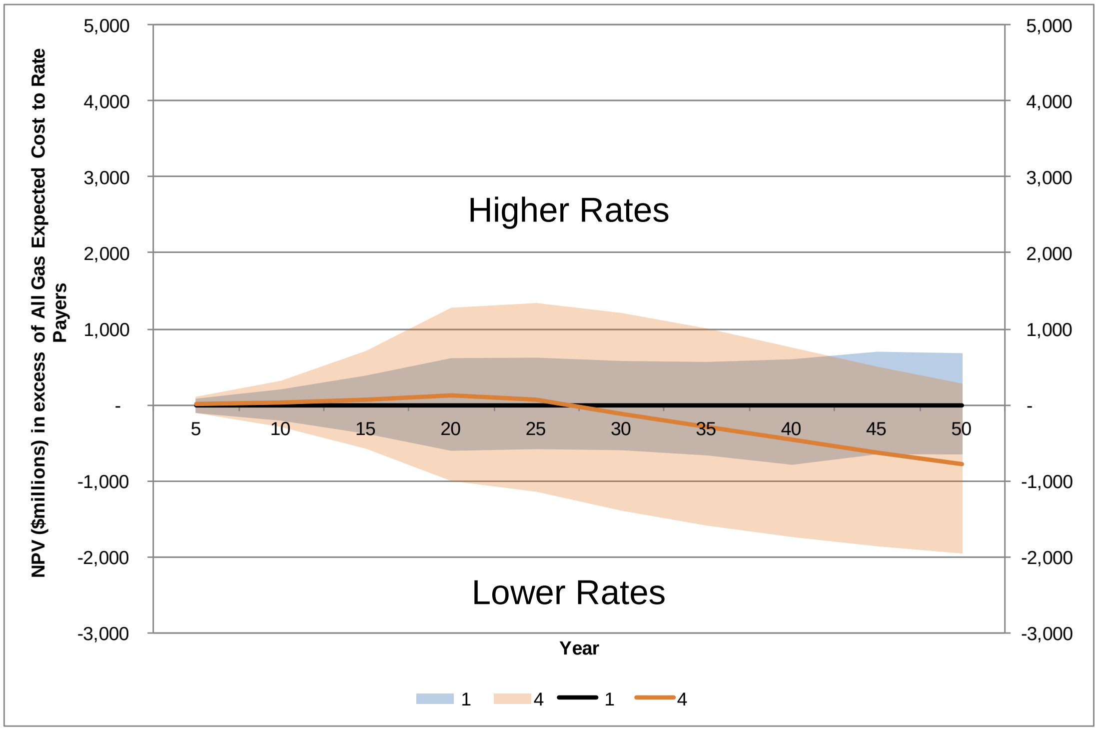
a) How has InterGroup satisfied itself that the issues raised on pages 3-7 and D-3 do not present themselves in this NFAT and therefore a more comprehensive consideration of the impact of Plans with more DSM and/or wind is not required?

ANSWER:

(a)

Mr. Bowman is satisfied that Plan 1 (All Gas) provides a reasonable starting point representation of the "Need-Based" concept and that Plan 4 (K19/Gas/250MW) provides a reasonable starting point representation of a basic "Opportunity-Based" concept for comparison purposes. The basic comparison can be seen in the following three figures:

Figure 16: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)



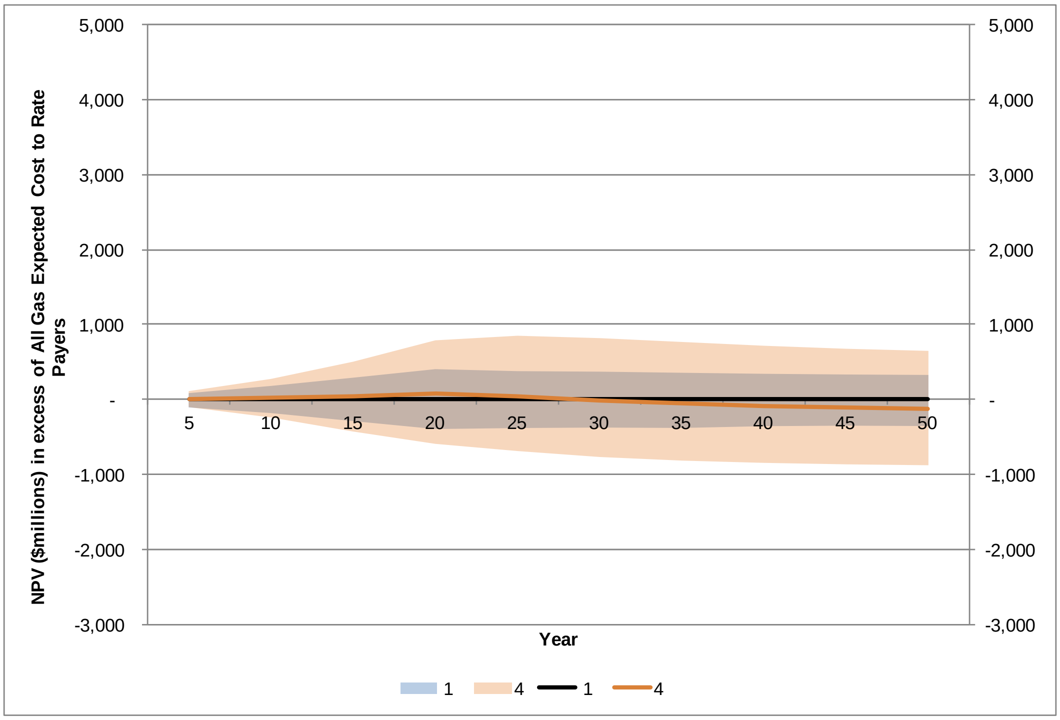
- Figure 16 in Mr. Bowman's Appendix C[1] indicates that the ratepayer impacts of these two plans at a reasonable discount rate:

  a) Do not indicate Plan 4 (K19/Gas/250MW) to be problematic over near term horizons (no expectation of higher rates over Plan 1 (All Gas)); and

  b) Substantially favour Plan 4 (K19/Gas/250MW) over horizons longer than 30 years.

[1] Page C-25

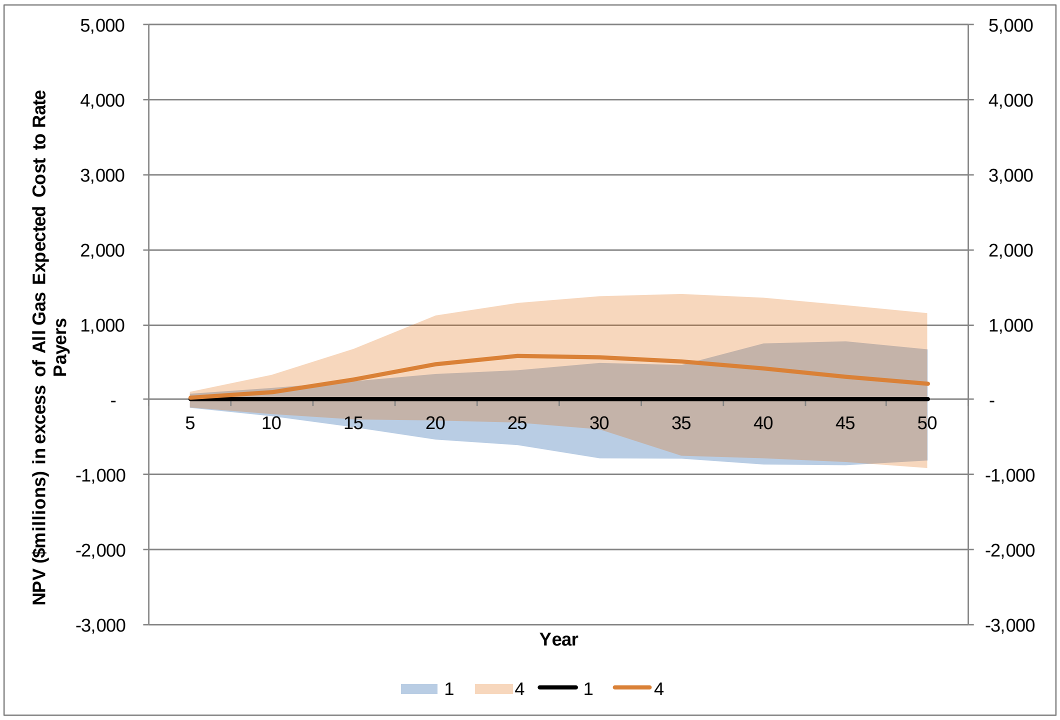
Figure 33: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 10% Real Discount Rate - NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)



- Figure 33 from the same Appendix[2] also tests these same two plans at a high discount rate (10% real) and Plan 4 (K19/Gas/250MW) remains competitive with Plan 1 (All Gas).

[2] Page C-44

Figure 21: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value - Low Energy Price Scenarios ($ Millions)



- Figure 21 from the same Appendix[3] shows the situation with the low export price scenario[4] – the worst single downside event in the sensitivity analysis. Under that downside case, Plan 4 (K19/Gas/250MW) is inferior to Plan 1 (All Gas), but at the worst expected value (at approximately year 30) the impact is an NPV of $500 million on a total amount paid in rates of approximately $35 billion, or about 1.5%

In short, under this initial comparison the benefits of a vision represented by Plan 4 (K19/Gas/250MW) is very competitive for ratepayers compared to the Need-Based vision as represented by Plan 1 (All Gas), with real but somewhat limited adverse risks. Given the significantly high non-monetary and third party benefits[5] of an Opportunity-

[3] Page C-31
[4] The assessment is done using the December, 2012 low export pricing. This pricing was developed at a particularly deep trough in export price expectations, which is 32% below the original 2012/13 forecast, and was increased 41% in coming up with the 2013/14 forecasts. Also note that this assumes no pricing for carbon at any time in the forecast horizon (CAC/MH I-203b).
[5] E.g., First Nations income sharing, GHG emissions reductions, better reliability due to US transmission, jobs and taxes, etc.

Based vision such as Plan 4 (K19/Gas/250MW) as compared to Plan 1 (All Gas), the decision to pursue an Opportunity-Based vision appears solid.

While the above quoted sections indicate that with a differently optimized level of DSM, it is theoretically possible that Plan 1 (All Gas) could be improved; it must also be acknowledged that Plan 4 (K19/Gas/250MW) may also be able to be improved. For Plan 1 (All Gas), it is Mr. Bowman's view that the degree of improvement available for ratepayers is likely relatively small if it exists. This is based on the following observations:

1) The 2013-2016 Power Smart Plan already includes a wide range of measures and achieves a RIM test result of only 0.9. This means that implementing the DSM measures proposed will lead to an upward pressure on rates - $1.00 in new net costs to ratepayers to achieve each $0.90 in net benefits (excluding common support and contingency costs the RIM ratio is unity - $1 in costs for each $1 in benefits, or not net adverse costs to ratepayers). While it is possible that some major measure has yet to be identified that could significantly enhance the DSM levels without eroding the economic standards that have been applied, these measures are unlikely to be substantial.

2) Scenarios that include wind (Plan 3 - Wind/Gas) are consistently not competitive with Plan 1 (All Gas).

The modelling of Plan 4 (K19/Gas/250MW) also suffers from a number of possible shortcomings that, similar to Plan 1 (All Gas) suggest that the actual scenario could be better than modeled; for example, the modelling assumes that all energy not sold under current long-term contracts is sold as a generic On-Peak Long-Term Dependable product each year. In practice, when Hydro has larger blocks of this type of energy, it is often sold to solid longstanding customers on the basis of good relationships as a premium product with what is understood to be better than average prices. Hydro's modelling to date is not based on achieving any better than the average export price in the future. The modelling of Plan 4 (K19/Gas/250MW) as shown in Appendix C of Mr. Bowman's evidence also fails to incorporate any quantified benefits of optionality that arise within the entire Pathway #3 (which also includes Plan 11 (K19/C31/250MW) and Plan 13 (K19/C25/250MW)).

In short, while it would be beneficial to analyze a fully optimized Need-Based Plan, such as a Plan 1 (All Gas) with potentially larger levels of DSM, or imports, or wind where these can be economically included, Mr. Bowman's strong expectation is that such a scenario would not fundamentally alter the basic conclusions in Appendix C of Mr. Bowman's evidence. Equally, it would be important to consider optimization of not only Plan 1 (All Gas) but also for Plan 4 (K19/Gas/250MW) which would be expected to further serve to reinforce the above conclusions.

REFERENCE: **InterGroup Report, page 3-9**

PREAMBLE:

The Report states that “a common standard for new bulk power projects such as hydraulic generation is that adverse impacts on financials or rates should not exceed somewhere in the order of 3-7 years until the “cross-over” point of costs into benefits”.

QUESTION:

a) What is the basis for this statement (e.g. where is this “common standard” used)?

ANSWER:

(a)

Please see MIPUG’s response to MH/MIPUG I-3.

REFERENCE: **InterGroup Report, page 3-6 (lines 4-5)** [Note: this is actually page 3-14, in the paragraph preceding Section 3.2.3]

PREAMBLE:

The Report states that "excess net income and retained earnings which go beyond that justified on the basis of achieving stable rates are not a benefit to customers – they are solely a benefit to Hydro's shareholder, and analysis of NFAT outcomes needs to reflect this allocation definitively, so as not to confuse what are costs to ratepayers and what are benefits to Hydro's shareholder".

QUESTION:

a) In its supporting analysis, InterGroup does not appear to have made any allocation of retained earnings contributions as between costs to ratepayers (for achieving stable rates) and benefits to the shareholder. Does InterGroup have any suggestions or insight into how this allocation should be performed?

ANSWER:

(a)

Mr. Bowman does not view a specific need to perform the noted allocation in the NFAT review. It is Mr. Bowman's submission that costs to ratepayers should reflect the total reasonable and prudent costs to operate the utility over time, including the costs of adverse impacts such as droughts. Rates to ratepayers in Manitoba should not include amounts which solely serve to build up retained earnings or pay dividends to a shareholder, or other mechanism to directly compensate the shareholder – this is not the basis for utility ratemaking legislation in Manitoba (unlike many other provinces in Canada).

To achieve a stable rate regime, the financing of events such as droughts should be achieved not by charges to ratepayers when the events occur, but rather through ongoing development of "reserves" of an appropriate form that are built up in good years and drawn down in bad years. Such reserves should serve to also benefit ratepayers in the form of avoided interest[1].

[1] Note that an important future consideration is whether this avoided interest expense benefit should flow through current rates or simply serve to help build up reserves faster. If ratepayers are benefitting from this interest cost savings via lower ongoing rates, then at the time the drought hits, ratepayers are burdened with a double impact – not only is it necessary to

Beyond this annual contribute/draw down model for reserves (only to the extent required to achieve rate stability) there is no demonstrated benefit to ratepayers from having ever-growing retained earnings, built up through rates. The benefit is likely solely to the shareholder[2]. In short, to the extent there is an "allocation" the benefits should be viewed almost 100% as being a benefit to the shareholder.

rebuild reserves, but there is also a loss of the avoided interest benefit. These items can serve to compound the rate shocks that may arise upon a drought.

[2] These amounts shows up as a benefit to the shareholder in various ways: 1) they represent a growing value of the wholly-owned utility; 2) they are reflected as annual income and government assets as Government Business Enterprises in the Summary Financial Statements.

REFERENCE: InterGroup Report, pages 4-7 to 4-8 and pages C-27 to C-28

PREAMBLE:

QUESTION:

a) Please confirm that InterGroup's rationale for supporting a 750 MW as opposed to a 250 MW interconnection is not based on the results of the financial analysis (which suggests Plan #4 is slightly more beneficial than Plan #6) but rather on the additional considerations set out on page 4-8 (lines 9-22).

ANSWER:

(a)

First, Mr. Bowman has not definitively supported a 750 MW line instead of a 250 MW line. The submission indicates that this line should "likely" be pursued, but the evidence to date is not conclusive and the ongoing exchanges as part of the proceeding will help resolve this decision.

Second, the rationale for Mr. Bowman's conclusion is in part based on the items noted at Page 4-8 lines 9-22. However, it is equally based on the response to PUB/MH I-279. Hydro's IR response notes that the comparison of Pathways with a 250 MW line and a 750 MW line have much closer Expected Values (EVs) than implied by NFAT Chapter 14. Specifically, based on NFAT Chapter 14, Table 14.4, comparing the best 250 MW Plan (Plan 4 (K19/Gas/250MW)) versus the best 750 MW Plan without the WPS investment (Plan 12 (K19/C31/750MW)) indicates that the commitment to the 750 MW line (in the absence of a WPS contract) would lower the EV by at least $150 million. This is a potentially significant figure.

However, looking to Attachment PUB/MH I-279 page 7, it is clear that with optionality considered, the EV impacts of the 750 MW line commitment depend on whether the decision is made to protect Conawapa for 2025. If the decision is not made to protect Conawapa, then committing to a 750 MW line is a net reduction in EV of $38 million[1], but if a decision is made to protect Conawapa, then net reduction in EV (net cost to commit to a 750 MW line) is only $9 million[2]. Each of these values are sufficiently close as to suggest effective equivalence between the two scenarios (the 750 MW line effectively

[1] PUB/MH I-279, page 7: Overall Expected Value Row – Plan 3B $957 million less Plan 4B $919 million.
[2] PUB/MH I-279, page 7: Overall Expected Value Row – Plan 3A $878 million less Plan 4A $869 million.

has no higher net cost than a 250 MW line). This also still reflects an optionality assessment that is not ideal, and may yet be improved (for example, see MH/MIPUG I-6).

REFERENCE: InterGroup Report, page C-14

PREAMBLE:

QUESTION:

a) Can Intergroup explain what gives rise to the difference in the timing of the "cross-over" point for ratepayer benefits as between its analysis and that of Manitoba Hydro?

ANSWER:

(a)

Manitoba Hydro has cited a cumulative rate cross-over timeframe of 10 - 15 years after the in-service of Conawapa[1]. Based on the PDP, this means somewhere in the period from 2035 to 2040. Given the financial modelling is based on rates for Plan 14 (PDP) being higher than all other plans starting in 2014/15; this is a cross-over of 22 to 27 years.

It appears Hydro has based their cross-over conclusion on the simple annual level of rates. For example, under REF-REF-REF, Plan 1 (All Gas) has lower rates each year than Plan 14 (PDP) until 2035, at which time Plan 14 (PDP) begins to have lower rates.

The main difference between Mr. Bowman's calculation of cross-over point and Hydro's calculation is the test applied. Hydro has applied a test that the level of rates *in a given year* is lower. Mr. Bowman has applied at test that the NPV of rates paid *in all years up to that point in time* is lower. In other words in Hydro's 2035 example, a ratepayer may be paying slightly less in that year than they would have, but they will still be substantially invested into the higher rates they paid for all of the years up to 2035.

The cross-over points for expected values shown in Appendix C of Mr. Bowman's evidence for Plan 14 (PDP) versus Plan 1 (All Gas) is approximately 45 years at a reasonable discount rate (5.05% real), and 35 years at a low discount rate (1.86% real). Comparing Plan 14 (PDP) to Plan 4 (K19/Gas/250 MW) the cross-over point is greater than 50 years at the 5.05% real discount rate (i.e., it does not occur within the financial modelling horizon) and 40 years at the low discount rate.

[1] NFAT Business Case, Chapter 11: Financial Evaluation of Development Plans, page 1 and 2 (August, 2013).