# Coalition - Book of Documents 2

# 1

## Excerpts from:

**James C Bonbright, Albert L Danielsen & David R Kamerschen, *Principles of Public Utility Rates* (Arlington, VA: Public Utilites Reports, Inc., 1988).**

**Please note that, where applicable, page numbers from James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961) are included in parentheses.**

**Given that the excerpts below are from the 1988 version, some words may differ in the 1961 version.**

The Rate Base: Original Cost with or without Adjustment for Price-Level Changes (chapter 12)

*Page 246 (not in 1961 version)*

"***Two Methods.*** FERC and other jurisdictions recognize that here are two alternate regulatory practices by which these carrying charges of debt interest and reasonable equity return on construction capital are recovered in rates. One method capitalizes the carrying charges incurred during the construction period as allowance for funds used during construction (AFUDC). AFUDC is recorded part as current income, part as an offset to interest expenses, but no cash payments are made by ratepayers during construction. The payments from ratepayers to recover the carrying charges begin when the completed plan goes on stream. The entire cost of the plant (including AFUDC) is added to rate base, and it earns a rate of return on investment and is depreciated over the life of that plant. The second method is to include construction work in progress (CWIP) in the rate base. (CWIP includes accrued AFUDC on investment not in rate base.) The regulatee recovers its carrying charges currently from ratepayers through the return component of its rates, rather than adding them to the cost of construction for recovery when the plant is in service. The return on CWIP is recorded as income on a current basis (like AFUDC), and actual cash payments are made by the ratepayers currently (unlike AFUDC)."

Original and Replacement Cost Standards of Rate Base (Chapter 13)

*Page 274-275 (page 202-203 of the 1961 version)*

"Applied under an original-cost philosophy of rate control, the rationale of the systematic transfer of capital costs originally charged to plant account into a series of smaller charges to operating costs is a corollary of the principle that the costs of supplying public utility services should be borne, as far as feasible, by those customers who derive a benefit from the particular outlays in question. It is for this reason that the burden of reimbursing a company for the acquisition of capital assets is distributed over the periods during which customers will enjoy the use of these assets. The gradual process of degradation of electric generators, for example, which are used less and less as they grow older, possibly being relegated to the status of stand-by equipment, is paid for by the customers using the electric power generated by said equipment. By the time the assets have ceased to perform a useful service, their costs should have been fully recovered."

*Page 275 (page 203 of the 1961 version)*

***"General Benefit Principles Applied to Cost Amortization.*** Since a benefit rationale is basic to the whole process of depreciation accounting, viewed as an instrument of rate regulation, one naturally looks to the same rationale for guidance as to a choice of a reasonable method or schedule of cost amortization. Equal allocations, one may assume, should be made to years of equal benefit; heavier allocations to years of heavier benefit. Or rather, the amortization of the costs should take place at such a pace that, in combination with the allowed fair rate of return on those capital costs that are still unamortized, plus the annual allowances for taxes imputable to those assets, it will impose annual burdens on ratepayers related as closely as feasible to the relative benefits conferred upon them by different years of use. In the determination of these relative benefits, account must be taken of the fact that the use of newer and more modern fixed assets will free ratepayers from the obligation to defray the heavier current operating expenses imposed by the retention of aged and obsolescent assets – expenses exclusive of depreciation allowances but inclusive of all charges for current maintenance."

# 2

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

NEEDS FOR AND ALTERNATIVES TO

REVIEW OF MANITOBA HYDRO'S

PREFERRED DEVELOPMENT PLAN

| | |
|---|---|
| Regis Gosselin | - Chairperson |
| Marilyn Kapitany | - Board Member |
| Larry Soldier | - Board Member |
| Richard Bel | - Board Member |
| Hugh Grant | - Board Member |

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

March 10, 2014

Pages 1255 to 1591

MS. JOANNE FLYNN: So the limit that we're talking about is related to planning for the system, so what this means is that there is a limit to how much we are willing to rely on as dependable energy. In the operating time horizon, the -- the system characteristics are there for the operators to use, so they have the choice in the operating time horizon.

If they see wind at minus two dollars ($-2) per megawatt hour, they can import. There's no restrictan -- restriction in the operation -- operating time horizon as to when they can import, but it will be affected by whether we have export obligations.

So in the on-peak hours, we tend to have export obligations, and you can't import and export at the same time, so we tend to -- to int -- we tend to import in the off-peak hours, which also tend to be the lower cost hours.

(BRIEF PAUSE)

CONTINUED BY MS. PATTIE RAMAGE:

MS. PATTI RAMAGE: I forgot to mention, Mr. Chair, we'll be passing the computer down as we go between witnesses.

(BRIEF PAUSE)

MR. DAVID CORMIE: Good morning, pa -- panel. I'm not used to sitting at this corner of the table. I feel like a lawyer today. And I'm not used to addressing Mr. Peters on the right and Mr. Williams on the left. I'm -- I'm a little bit confused. It's good to be back.

As Ms. Flynn has described and as we've indicated in our filing, Manitoba Hydro's planning involves a combination of activities: new generation, new transmission, additional imports and export sales, and a commitment to expanded DSM.

The purpose of my evidence this morning is discuss the critical roles that exports hold at Manitoba Hydro, how interconnections have been and will be key in the future.

As well, I -- as well, I will provide updated information on the recently signed sales agreements with Wisconsin Public Service, potential new agreements, progress on the new 500 kV interconnection, and an update on the Great River Diversity Exchange Agreement that was signed last fall.

Exports and the revenues that they generate are very -- a very high-profile activity. We account hour by hour for the revenues that are generated, and report continually on the value of that activity, at times at much -- in much detail. This isn't surprising, given that they can make up 40 percent of the Company's revenues.

What is less obvious and much more lower-profile are the other values that our export activities create. There is no ongoing accounting of the cost saved or of the emergencies avoided because Manitoba has chosen to be interconnected to its neighbours, but our Preferred Development Plan that we are proposing does that. It is a combination of increased exports, increased imports, and increased reliability and these revenues and the reduced and avoided costs have been included in the economic analysises (sic) in all the comparisons.

Our plan is a plan that recognizes that through continued coordinated efforts with our neighbours, that more can be achieved by working together than by proceeding alone.

What are the shared benefits from working with our neighbouring utilities? Firstly, there's the efficient use of capital. Hydro was built in large blocks. Surplus capacity that's available can be sold. In-service dates can be adjusted. Capacity can be shared when there is a lo -- is load diversity. Generation reserves can be minimized through pooling of reserve capacity.

From a production costing savings, fuel costs can be min -- minimized through economic dispatch. Why run an expensive generator when your neighbour has a lower-cost generator that can be run instead?

Why should Manitoba run an expensive, inefficient combustion turbine when a neighbour has a more efficient combustion turbine that can be run as an alternative? And for a hydro utility like Manitoba Hydro, surplus water can be used rather than being spilled and wasted by exporting the electricity.

In emergencies, we can help each other out. When the transmission system is damaged, power flows change direction instantly. Exports become imports, and the lights stay on, and maximizing the use of renewable resources that don't harm the environment.

But the key to all that -- the key to being able to achieve these benefits is the interconnecting transmission lines, and so to -- and so it should be no surprise that in Manitoba Hydro's Preferred Development Plan, the one plan that has the maximum benefits is the one that involves new export transmission, increased export sales, increased energy imports, additional seasonal diversity arrangements, and improved reliability.

The practice of building interconnections in conjunction with new hydro plants is not new. This chart indicates Manitoba Hy -- Hydro's history of export volumes for the past fifty (50) years. As the system was expanded, export volumes grew to where they are today, to approximately 10 million megawatt hours in an average water year.

Development of Grand Rapids, Kettle, Long Spruce, and Limestone all involved associated increases in -- in interconnection capacity. Each new plant generates surplus energy, and -- and the power planners of those days chose to increase market access to capture the value of that surplus.

The obvious benefit of the existing interconnections has been the $10.3 billion in export revenues that have been generated from these sales since 1960. The benefit is most dramatically shown as the value of surplus energy from Limestone alone has been in excess of $6 billion for a plant that cost $1.6 billion to construct.

So as we've now ponder the future with the development of Keeyask/Conawapa the amount of surplus energy will increase again, doubling under favourable water conditions. Expanded transmission to the United States will allow Manitoba Hydro to capture and maximize the value of that surplus energy.

However, there are other unaccounted for benefits of the existing interconnections. There have been no blackouts in Manitoba since the large 500 kV interconnection came into service in the late '70s. Drought costs have been significantly reduced because lower cost purchase power was available during the droughts of 1982 to 1992 -- I'm sorry, 1988 to 1992 -- and again in 2003/2004.

And required generation reserves in Manitoba are 80 percent less because Manitoba Hydro has generation reserve-sharing arrangements with the neighbouring region. These avoided costs have benefited consumers through lower rates than would otherwise be necessary, and an expanded interconnection will bring similar benefits.

These include increased reliability, the existing 500 kV interconnection will have a back-up, they will reduce our exposure in droughts, and it will increase reliability to the region should this line be lost, in addition, increased ability to buy power at lower -- low-cost off-peak energy rather than have to import more expensive on-peak energy or burn natural gas during energy-short periods.

In the NFAT filing, Manitoba Hydro has identified this period as a window of opportunity. So what is that window of opportunity? It's a window of opportunity to work with our neighbours in a manner that maximizes the benefit for all parties.

It's a limited opportunity, because there are also ma -- because they are also making strategic decisions now. It's a limited opportunity because we've convinced them over the past several years to expand their set of planning options to include significant long-term reliance on Manitoba Hydro.

Minnesota Power and Wisconsin Public Service, Northern States Power, Saskatchewan Power all face daunting challenges, too. And the uncertainty associated with planning for load growth is not new, but today these highly coal-dependent utilities are wrestling with additional uncertainty in decisions regarding the future of aging generating fleets, with their traditional fuels being outlawed, with new fears about nuclear, with gas price volatility, and with emerging resources like wind and natural gas generation that are only partial solutions.

A purchase from Manitoba Hydro is an attractive option to them. We have indicated to them, firstly, that we are prepared to make long-term commitments for renewable, dependable hydraulic energy, that we can offer stable, predictable pricing, that we can offer them resource diversity, and that investing in new transmission will give them long-term access to our surplus hydro energy.

These companies have seen values in these offers, and have seen the value of having increased certainty. On the basis of our long-standing reputation with them, they have agreed that this is an opportunity for them too, in facing the future with Manitoba Hydro as a partner. This opportunity won't come again soon.

Since 2008, Manitoba Hydro and its US customers have agreed to several power sale agreements at very attractive rates that are dependent on the construction of new hydro generation and transmission. The first agreement is the NSP 125 -- 125 megawatt system power sale that goes from 2021 to 2025, and this agreement is subject to the construction of Keeyask.

The second agreement is a hundred megawatt power sale from 2021 to 2027. It's also subject to Keeyask.

The third agreement is the agreement with Minnesota Power for 250 megawatts from 2020 to 2035, subject to Keeyask and the construction of a new interconnection.

And, most lately, with Wisconsin Public Service, a 308 megawatt system power sale from the in-service of Conawapa to 2036, again subject to Keeyask/Conawapa, and the new interconnection.

With these contracts, these utilities are choosing not to build alternate supply resources, but to rely on Manitoba Hydro as the supplier. Without these contracts, these utilities will invest in other long-term supply options to meet their needs. The opportunity for Manitoba Hydro to displace these other options will not return. They will be lost.

The contracts that have been signed to date for hydraulic energy effectively use up most of the surplus power -- hydro power available from Keeyask. However, export discussions with Wisconsin Public Service, Great River Energy, and Saskatchewan Power and others continue, mainly for the power from Conawapa.

With Wisconsin Public Service, under the 500 megawatt term sheet, discussions continue on up to another 200 megawatts in addition to the 308 megawatts

(BRIEF PAUSE)

THE CHAIRPERSON: I'm looking very specifically at the dependable -- dependable supply line, which seems to be dropping around twenty (20) -- 2025/'26, '26/'27. Could you explain what's going on there?

MR. DAVID CORMIE: Yes, Mr. Chairman. At the -- in -- in that time frame, the existing contracts with Northern States Power expire. As part of that termination, the seasonal diversity contracts expire, and also the adverse water provisions that are built into those contracts are -- expire. So there's a reduction in dependable energy associated with the expiration of those contracts.

Should those contracts be rolled over on an equivalent basis, there would not be that -- be that dip at that time, and, so then it -- it -- you know, essentially that explains the -- the reasons.

THE CHAIRPERSON: So a follow-up question would be given that DSM will -- will shift that -- that Manitoba firm energy line downwards once it -- it -- once DSM is implemented at whatever level that's involved, it -- it does suggest that the amount of debend -- depenable supply available for contracting has increased.

MR. DAVID CORMIE: Yes, if -- if the -- the Manitoba firm energy demand isn't as high as indicated here for -- for whatever reason, load -- load growth or DSM, there will be more opportunity to enter into longer and larger export contracts than we are planning.

I haven't indicated it here, but if you were to put -- and I think Mr. Thomson alluded this, too, in the -- in the -- on the first day of the hearing. All the contracts that we are in -- or all the -- all of the discussions that we are having with the various customers exceed the dependable energy supply line that we're showing there.

And so we're in discussions for more dependable energy post-Conawapa than -- than we have -- have supply.

So there is room there. And there's market interest there to -- to increase, should the Manitoba load be lower. And -- and we are continuing to seek out all opportunities, so that at the end of the day, we can bring back the best value and best portfolio to -- to fill the -- to fill that -- to fill that gap, or whatever it is.

MR. ED WOJCZYNSKI: You just men -- and

-- and another part of the answer to that is, as we just talked about, Dr. Bel asked about the in-service dates of the gas turbines. If we have a higher DSM, and we don't change the amount of exports, we would defer when the -- when the gas turbine comes in.

So you have two (2) choices. You can either defer when the gas turbine comes in that sequence, or you can do more from exports. You -- you have -- we have choices.

THE CHAIRPERSON: Mr. Cormie, you -- you -- I think your example, you talked about Conawapa as being -- once it's built, you -- you have available contracts.

But looking towards Keeyask, which is going to be much earlier, are you -- is it your goal to -- to sign more export contracts, firm export contracts, during that time period once Keeyask is built, over and above what we're seeing here?

MR. DAVID CORMIE: Yes, we -- well, I haven't shown the term sheets and the MOUs that are under discussion now that -- that we believe that we will sell all the -- the -- all the dependable energy, not just the hydro dependable energy that's coming off Keeyask. We will be able to fill that -- fill that, maybe not exactly a hundred percent, but very, very close because you can see that we actually have a wedge of energy to sell, and people don't like to buy wedges. They want to buy, you know, a hundred megawatts for ten (10) years, and not a hundred in the first year, ninety (90) in the second year. So we may not be able to sell out in the -- in the very earliest years, but in a sense, we will sell out all the dependable energy. And so, yes, we are -- we're in discussions with -- with customers to sell the balance of the dependable energy, starting in -- in 2020.

THE CHAIRPERSON: I'm trying to understand the psychology of the -- of the buyer from the other side.

Now, why would the term of those contracts be four (4) or five (5) years, as opposed to, say, fifteen (15) years where you basically don't have to worry about it anymore. It's somebody else's problem to supply your ratepayers?

MR. DAVID CORMIE: I -- I can't speak for -- for the customers, but I -- I don't think we've been involved in a long-term sale of five (5) years. I think, generally, they would be in the ten (10) year time frame, and -- and we would use innovative contract structures, like we have done with the Xcel or the NSP sale agreements to deal with -- to deal with the -- the drought and the dependable issue out in the -- in the longer time frame to manage that issue of the wedge.

For example, the NSP sale agreements right now put no net obligation on the Manitoba Hydro system in a sense. NSP is backstopping the dependable energy requirement of the contract with their own resources through the diversity purchases and our adverse water right to curtail deliveries if -- if it makes sense.

So we would -- if we get into the position where we're -- we're not meeting the long-term -- you know, the -- the dur -- the term of the contract that the customer would like, we would then negotiate something that would help -- have them provide the dependable energy that we could -- and we could exercise that right in order to get the term that would be appropriate for them.

(BRIEF PAUSE)

THE CHAIRPERSON: I believe that's all the questions that the -- the panel has for the time being. It is four o'clock, and we are considerably later than the schedule anticipated, so having canvassed the panel at the break, we're quite prepared

# 3

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO
NEEDS FOR AND ALTERNATIVES TO
REVIEW OF MANITOBA HYDRO'S
PREFERRED DEVELOPMENT PLAN

Regis Gosselin - Chairperson
Marilyn Kapitany - Board Member
Larry Soldier - Board Member
Richard Bel - Board Member
Hugh Grant - Board Member

HELD AT:

Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
March 19, 2014
Pages 2709 to 2980

MR. DARREN RAINKIE: The -- the difficult part with those types of calculations, the one (1) year in-service calculation, is that it's not really a reflection of what really would happen. In fact, when -- when you look at the -- I'm trying to remember some of the -- the runs that -- and maybe this will become clear when we file the runs with the higher capital cost, is that -- is that even with the higher capital costs of Keeyask and Conawapa, which were, I suppose, approaching the order of a billion dollars, I think it was a $300 million change and a $500 million change, I think the -- the pressure on rates in the first twenty (20) years would only be a quarter of a percent.

And if you stretched out the timing of the achievement of the 25 percent equity ratio, I think we could still maintain the -- something close to the 4 percent. It's simply a function of the fact that once you have these generating stations spinning, you have a significant cashflow and net income, you know, at the back end.

And one (1) of the things you have to look at in a hydroelectric generating station is the financial profile of it. People tend to look at the first ten (10) years when it's in service. But the financial profile of a hydroelectric generating station is, yes, it's a lumpy piece of capital that comes in, but as -- as we generate income from it to start paying down the debt over time, the costs actually go down.

If you assume, you know, a normal economy, where prices are gradually increasing, there may be business cycles where it goes up and down, but we're talking about a hundred-year asset here. The -- the revenues out of it are coming up, right. We have a cost-of-service type of mentality, where we feather in rate increases over time. We don't -- we don't take the actual carrying costs of an asset and jam it right into rates the first year.

When you combine all of those factors into the -- into the mix and look at the financial profile of a hydroelectric generating station, once you have that, even if there are some cost overruns, and we don't want that to happen and we're going to carefully manage that, it still is a hugely viable -- it's still the -- the cheapest, lowest cost electricity you're going to get over the long run. And -- and it's manageable because we don't take all of the carry -- the extra costs of -- of the overrun and jam it into rates on year 1.

So it's -- it's -- sorry, that's a bit

of a long-winded answer, but you have to look at the financial profile -- to understand the real answer to that question you have to look at the financial profile of a hydroelectric generating station and understand what you're dealing with.

When we tend to do these one (1) year revenue requirement calculations the year it comes in service, it -- it results in a picture that just doesn't -- doesn't make sense. And I think we're going to get into that -- I've looked at Mr. Peters's book of documents -- later.

But when you look at things -- when you look at the financial profile, you -- you got to get past the first ten (10) years where you're not generating enough revenue to cover the costs. You have to look at the entire time frame of that generating station. And I think that's one (1) of the points that's maybe miss here in the -- in the proceeding.

People tend to get scared at the upfront investment, but they don't look over the long ,run.

THE CHAIRPERSON: Just, you know, it's -- just to argue -- it probably is just to -- the debate we're having, you know, the -- you've already established what your revenues are. If you -- if you make a mistake on the capital costs, there really no --

there are no more revenues to be obtained from the marketplace other than what you can get from ratepayers.

And I'm simply trying to establish a worst-case scenario whereby something goes wrong in the capital construction costs and that the impact of that, in broad view, goes right to ratepayers at the -- at the front end. I'm very concerned about the potential that -- that our carefully crafted pictures that we're drawing here, if we are wrong, the ratepayers get it right on the chin at the front end.

And I just want to be convinced otherwise.

MR. DARREN RAINKIE: That's what I was trying to convince you, Mr. Chairman, in my rambling responses, is that -- is that, if you had a cost overrun of a billion dollars, I think was your scenario, just for a round number, and if you assumed the carrying costs were 8 percent, $80 million, we would not jam that into customers in the front end.

There is sufficient benefits from a hydroelectric generating station over the hundred-year life that we would smooth -- we would smooth that in over time. So the customer would not all -- the -- the customers at the front end would not pay the freight --

all of the freight, if you like, that we would allow that through our cost-of-service rate-setting methodology to come in over time.

Of course, customers have to pick up the total cost of the Company over time. I mean, it's -- it's just the fundamental, you know, principal of Manitoba Hydro. There's no shareholder here that's earning a 10 percent return. We -- we work on behalf of the -- of the ratepayer, and we have to get a decent recovery of our costs over time to maintain, you know, a financially viable company for customers. In the -- in the end, the retained earnings that we have are for customers. They're not for a shareholder. They're not for bonuses.

But the -- the beauty of a hydroelectric generating station is that you have that flexibility. If there are some things a little bit off the beaten path in the front end, there's more than enough cashflow in the back end -- well, and -- and starting right when it starts to go in-service, to -- to cover that off without needing to go directly to customers and -- and tapping their pocketbook. And that's a fundamental thing here, is understanding the financial profile of the hydroelectric generating station.

(BRIEF PAUSE)

MS. LIZ CARRIERE: So on slide 53 we're looking at the net income of electric operations under the three (3) development plans reference scenario. And what you can see is that each of the development plans result in relatively low levels of net income in -- in the first ten (10) years.

The All Gas Plan results in losses for seven (7) years, mainly due to the amortization of the sunk costs relative to the Preferred Development Plan. And rates in practice would need -- likely need to be adjusted higher so as not to substantially deplete retained earnings over that ten (10) year time frame. Net income over the longer term converges and -- and is a result of the -- the adjustment of the -- the rates to meet the one-twenty (120) interest coverage target.

On the interest coverage ratio, we tend to -- it's almost a mirror image of the -- of the net income graph. We're below target for twelve (12) to fourteen (14) years under each of the scenarios. The All Gas net losses on the previous slide also results in interest coverage below one (1) for a number of years.

While the interest coverage weakens in

# 4

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

GENERAL RATE APPLICATION

2014/15 AND 2015/16

Before Board Panel:

| | | |
|---|---|---|
| Regis Gosselin | - | Board Chairperson |
| Marilyn Kapitany | - | Board Member |
| Richard Bel | - | Board Member |
| Hugh Grant | - | Board Member |

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

May 28, 2015

Pages 959 to 1230

MR. BOB PETERS: And while you're doing that, Mr. Miles, I had understood from reading the filing that Mr. Cormie was busy trying to work on the business case for Conawapa.

Mr. Cormie, you still are in contact with prospective purchasers of Manitoba Hydro's energy?

MR. DAVID CORMIE: Yes, Mr. Peters.

MR. BOB PETERS: And in respect of possible generation from Conawapa?

MR. DAVID CORMIE: Yes, Mr. Peters.

MR. BOB PETERS: And when, Mr. Cormie, do you believe you'll be in a position to put forward a business case in respect of Conawapa?

(BRIEF PAUSE)

MR. DAVID CORMIE: It -- it won't be for a -- a couple of years, Mr. Peters.

MR. BOB PETERS: That's --

MR. DAVID CORMIE: And -- and the reason I say --

MR. BOB PETERS: You're not putting an end date on it is what you're telling me?

MR. DAVID CORMIE: Yeah. The reason I'm saying that is our -- our market for a large sale, in addition to what we've already committed to Wisconsin, is -- is in the United States. And -- and until the EPA clarifies what the rules are under the Clean Power Plan, and until the states say what their implementation plans are going to be, utilities don't know what to do. They need to know what the rules are.

And so to have a large US utility say today that, We're going to commit to -- to a large power purchase from Manitoba Hydro, they can't, because the ground is shifting. And so, you know, we can have discussions, but no one is going to commit to a term sheet with Manitoba Hydro at -- at this point until that -- that clarity is received.

And there is -- there is demand in Saskatchewan and we're working with them, but that demand isn't sufficient at this point to trigger Conawapa. So it -- it will -- it will take us several years to -- to have some clarity so that a -- a US customer can say, You know, this is -- this is the right thing for our customers; it's consistent with -- with the regulatory requirements of the federal government and the state governments. And only then would -- would they -- would they commit to signing some agreement with Manitoba Hydro.

MR. BOB PETERS: It sounds like for all

of those thinas to settle down. Mr. Cormie. it takes us out to closer to 2020 or bevond?

MR. DAVID CORMIE: What -- what's happenina in addition to that thouah. Mr. Peters. is that there's a huae amount of coal aeneration in Minnesota that has to retire. And so when vou look at the suoolv and demand situation for the State of Minnesota bv 2030. it becomes verv orecarious. The nuclear olants are reachina the end of their life. Most of the coal is shut down. You can't run a state electricitv svstem on wind and solar oower. It won't work.

You need base load resources. And so. vou know. that's where Manitoba Hvdro brinas value to the table. And if we wait till 2020. we can't meet the need in 2030. It takes ten (10) vears to build Conawaoa. It will take mavbe five (5) vears to aet throuah the reaulatorv orocess. to ao throuah the environmental thinas. to come before a oanel such as this to do the business case of Manitoba.

So. vou know. as I said. a couole vears. If we don't have somethina in a couole vears. it -- Conawaoa won't be triaaered bv somethina in the United States. It -- it essentiallv will fall off the table as an oooortunitv to solve the issues that the State of

Minnesota has.

It doesn't mean that Conawapa won't be -- be built, but it'll be built based on the need in Manitoba. That's something like Mr. Miles said, out in 2037 we're starting to run short of -- of resources, so the question is: Do we build it for Manitoba? Not because we're building it as -- based on a business case that I've been able to put together with some -- some export customers.

2020 is too late. And we've told our customers, and the regulators, and the politicians, the United States, if you think that Manitoba Hydro will be part of the solution to meeting the EPA requirements in 2030, you need to tell us now, because it's going to take many years for us to prepare and to build that plant, so that by the time you get to 2030, or 2031, or 2032, that we can help you.

MR. BOB PETERS: Mr. Cormie, has Manitoba Hydro ruled out Conawapa as a merchant plant?

MR. DAVID CORMIE: Well, that -- that's what I've been talking about. Building a business case so that the risks of -- of Conawapa aren't borne -- of Conawapa advancement aren't borne by the domestic customers. There has to be enough of -- of firm commitments so that, you know, if the risk of building the plant isn't -- isn't borne by -- by the -- the costs of -- of advancing Conawapa for ten (10) years is fully borne by the people who are buying the power.

And -- and fundamentally, that was the problem with the case that -- that was presented at the NFAT, is that we were only halfway through that process of -- of bringing the customers to the table. And that's why we weren't asking for approval of Conawapa. We weren't prepared to reach a segment. We're -- we're going down that path.

And we would only come to the -- to the Board when the business case was robust and that -- that the uncommitted portion of the output of the plant wasn't -- the risk of that weren't being borne by the customers. So we're -- we're working on that, but it'll take several years for it to happen.

MR. BOB PETERS: Thank you. Turning to page 160 of the book of documents, Exhibit PUB-20, there's a number of listings here of export contracts after 2015, Mr. Cormie and Mr. Miles, that are considered dependable from an energy perspective. Page 160. Thank you.

I'm going to ask if there could be an undertaking from you gentlemen to quantify the dependable energy required under each of the listed

# 5

# The Public Utilities Board

# Report on the
# **N**eeds **F**or and **A**lternatives **T**o (NFAT)

## Review of Manitoba Hydro's Preferred Development Plan

June 2014

### 8.6.6. Discount Rate

Selection of the appropriate discount rate to apply over a 78-year time period is open to debate. Justification of a high discount rate can be based on the social cost of capital; an intermediate rate based on the current cost of borrowing; and a low rate based on views of inter-generational equity such as has arisen in treatments of the future impacts of climate change. The issue is magnified in the case of the Preferred Development Plan, which entails large expenditures in the near future with the expected net benefit accruing many years in the future.

The discount rate that Manitoba Hydro used in the economic evaluation accordingly drew comment. The discount rate in the economic evaluation context is designed to reflect the return that markets require from the type of investment in question.

CAC's expert Mr. William Harper was of the view that Manitoba Hydro understated the cost of equity, resulting in a lower discount rate than what should be applied in the analysis. Mr. Harper indicated that the allowed return on equity was higher in other jurisdictions than the amount assumed by Manitoba Hydro, which was notionally based on 300 basis points over the cost of debt, including the debt guarantee fee. Calculating the Net Present Value at the rate that Mr. Harper felt was appropriate (5.2%,[294] subsequently updated to 5.55%[295]) results in in lower NPV values for all plans.

Furthermore, CAC and MIPUG's experts argued that it was not appropriate to include the discount rate as an uncertainty because it challenges the ability to compare the alternatives and makes the discount rates and interest rates difficult to separate. Manitoba Hydro's expert acknowledged that the explicit treatment of the discount rate as an uncertainty is challenging, but stated that it is an accepted practice.

## 8.7.0 Conclusions of the Panel

The Panel accepts that Net Present Value (NPV) is an appropriate metric and a useful guide to decision-making. However, other metrics such as the Internal Rate of Return (IRR) and Cumulative Present Value (CPV) complement the Net Present Value analysis and have been considered by the Panel in assessing the economics of the plans.

Based on the March 27, 2014 updated information (which reflects only increases in the capital costs of Keeyask and Conawapa based on 2012 assumptions and the lack of Wisconsin Public Service investment, but does not reflect enhanced DSM or the new pipeline load), plans with Conawapa have a lower expected Net Present Value than

[294] Exhibit CAC-30 pp. 20-21.
[295] Exhibit CAC-69, p. 26.

plans without Conawapa. This means that on a risk-adjusted basis, it is not economic to pursue Conawapa.

Furthermore, the comparative economic benefits of the Preferred Development Plan at reference conditions have deteriorated significantly since Manitoba Hydro's NFAT Submission was filed in August 2013. In August 2013, Manitoba Hydro suggested that the Preferred Development Plan would have an incremental Net Present Value of $1.7 billion compared to the All Gas Plan. Since then, based on changed assumptions this advantage has disappeared virtually completely. The incremental Net Present Value is now only $45 million. Accordingly, it is clear that the economic analysis does not support proceeding with the Preferred Development Plan. Given the current economics, the plan does not break even until 2089, which is at the end of the 78-year planning horizon.

The Panel further agrees with Manitoba Hydro's expert witness, Dr. Borison, that Expected Values are one of the most important risk analysis outputs in comparing the economics of plans. Manitoba Hydro was not able to provide the Panel with fully updated Expected Value calculations before the completion of the hearings. Manitoba Hydro only provided non-risk-adjusted "reference" Net Present Value based on complete updated 2013 assumptions. This is unfortunate, as it left the Panel without one of the important decision-making tools at its disposal. The Panel has no choice but to extrapolate. In the last full economic analysis, which had a non-risk-adjusted reference Net Present Value of $614 million, the relative Expected Value was only $120 million. Since the non-risk-adjusted Net Present Value has now further deteriorated from $614 million to $45 million, the Expected Value compared to the All Gas Plan is now likely negative.

The plans that include Keeyask and the 750 MW transmission interconnection, on the other hand, break even compared to the All Gas Plan after approximately 50 years. While they are still a long-term proposition, they fare significantly better than the Preferred Development Plan.

The Panel notes that the economic analysis supports the building of a 750 MW transmission interconnection to the United States. There are measurable economic benefits associated with the transmission line relative to the All Gas Plan without an interconnection. Leaving the economics aside, there are also tangible reliability benefits associated with the transmission intertie, including the ability to import additional power in times of drought and during emergencies.

Manitoba Hydro was not able to provide the Panel with fully updated Expected Value calculations before the completion of the hearings. Manitoba Hydro only provided non-risk-adjusted "reference" Net Present Value based on complete updated 2013 assumptions. This is unfortunate, as it left the Panel without one of the important decision-making tools at its disposal. However, the Panel is prepared to extrapolate. In the last full economic analysis, the Preferred Development Plan had a non-risk-adjusted reference Net Present Value of $614 million, and the relative Expected Value was only $120 million. Since the non-risk-adjusted Net Present Value has now further deteriorated from $614 million to $45 million, it stands to reason that the Expected Value compared to the All-Gas Plan is now likely negative.

The various iterations of economic analysis from the August 2013 NFAT Submission until the end of the NFAT Review hearing have shown a narrowing of the gap between the various development plans and the All Gas Plan. But plans with Keeyask and a transmission interconnection to the U.S. have all outperformed the All Gas Plan by margins that are materially better. On the basis of the results of the economic analysis, the Panel can see no reason to support the All Gas Plan.

The Panel does not consider the Embedded Return on Equity to be a particularly useful metric in reaching its conclusions.

## 9.5.0 Impact of Development Plans on Electricity Rates

Manitoba Hydro's initial evaluation showed that the Preferred Development Plan would result in equal annual rate increases of 3.95% through 2031/32. Other development Plans ranged from 3.43% for Plan 1 (All Gas) to 3.86% for Plan 7 (Gas/Conawapa 26). The magnitude of rate increases under all options was significantly higher than the forecast level of inflation. Over a 78-year time frame, the Preferred Development Plan had the lowest overall cumulative nominal annual rate increases compared to other plans at 106% versus 176% for Plan 1 and 134% for Plan 7.[314]

The financial evaluations based on Manitoba Hydro's March 10, 2014 update project higher even annual rate increases to 2031/32 for plans that include Keeyask and/or Conawapa. The new analyses, which assumed implementation of DSM Level 2, Manitoba Hydro's new higher reference capital costs for Keeyask and Conawapa, and the 2013 Electric Load Forecast scenario, projected even annual rate increases from 2015/16 through 2031/32 as shown in the Table below.[315]

The financial evaluation reveals significant rate increases for all plans. Over the entire 50-year evaluation period to 2061/62, the hydro-based plans (with no gas) have the lowest rate increases, but over the medium term (through 2031/32), plans that include gas have the advantage over hydro-based plans.

Starting in 2015/16 and continuing to 2031/32, the Preferred Development Plan would see projected even annual increases of 4.38% (with DSM Level 2 with reference assumptions and reference costs and pipeline load), rather than 3.95%, as Manitoba Hydro first projected. This increase stems largely from higher capital costs estimates for Keeyask and Conawapa, lower forecast domestic load and Wisconsin Public Service (WPS) declining to invest in the U.S. transmission line. As reflected in the Table below, if capital costs increase to Manitoba Hydro's new high capital cost scenario upper limit, annual rate increases associated with the Preferred Development Plan are projected to be 4.63% over the period to 2031/32.

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[314] PUB/MH I-0149a, Revised, p. 7.
[315] Exhibit MH-104-12-6, p. 1.

**Table 20 Projected Even Annual and Cumulative Rate Increases by Development Plan, 2013 Assumptions/DSM 2/Reference & High Capital Costs (Main Submission Rate Methodology)**

| Plan # | Even Rate Increases 2015/16 to 2031/32 | Even Rate Increases 2015/16 to 2061/62 | Cumulative Nominal Rate Increases at 2031/32 | Cumulative Nominal Rate Increases at 2061/62 |
|---|---|---|---|---|
| Plan 1 (All Gas) | 3.36% | 2.02% | 82% | 161% |
| Plan 1 (All Gas) (Pipeline Load) | 3.52% | 2.05% | 87% | 165% |
| Plan 2 (K31/Gas) | 3.55% | 1.85% | 88% | 141% |
| Plan 5 (K19/Gas25/750MW) | 3.74% | 1.72% | 94% | 126% |
| Plan 5 (K19/Gas/750MW) (MP & WPS Sales) (High capital costs) | 3.99% | 1.72% | 102% | 127% |
| Plan 5 (K19/Gas/750MW) (MP & WPS Sales) (Pipeline Load) | 3.86% | 1.79% | 98% | 135% |
| Plan 6 (K19/Gas/750MW) (MP Sale) | 3.75% | 1.70% | 95% | 125% |
| Plan 12 (K19/C40/750MW) (MP Sale) | 3.76% | 1.55% | 95% | 109% |
| Plan 14 Preferred Development Plan (K/19/C31/750MW) (MP & WPS Sales) | 4.27% | 1.30% | 112% | 86% |
| Plan 14 Preferred Development Plan (K/19/C26/750MW) (MP & WPS Sales) (Pipeline Load) | 4.38% | 1.37% | 115% | 92% |
| Plan 14 Preferred Development Plan (K/19/C26/750MW) (MP & WPS Sales) (High capital costs) | 4.63% | 1.35% | 125% | 91% |

## 9.6.0 Impact of Demand Side Management Programs on Rates

Manitoba Hydro's DSM programs and plans were discussed earlier in this report.

In preparing its financial evaluation updates, Manitoba Hydro assumes that it will be implementing higher levels of DSM, and determined that DSM Level 2 adds the most value to Manitoba Hydro and customers who take advantage of the DSM programs.

Manitoba Hydro is forecasting expenditures totaling $822 million from 2014/15 to 2028/29 for Electric Power Smart programs and initiatives.[316] Annual expenditures on DSM programs are amortized over ten years and included in rates. Furthermore, the reduction in domestic load from DSM programs will create an increasing revenue shortfall that must be offset by increased rates, unless the energy saved can be sold on the export market at prices that fully offset the loss of domestic revenues from DSM.

While all customers bear the impact of the costs of DSM programs, customers who take advantage of available programs have an opportunity to mitigate the rate impacts by reducing their energy consumption and lowering their energy bills, as further discussed below.

## 9.7.0 Impact of Sunk Costs on the Projected Rate Increases

The rate impact of the sunk costs of the Keeyask and Conawapa projects was identified as an important issue in relation to the financial evaluation of the projects. Sunk costs, which are currently estimated at $1.6 billion,[317] are the estimated expenditures that will have been incurred by June 2014 to protect the respective in-service dates for Keeyask and Conawapa.

Manitoba Hydro's financial evaluation assumes that these sunk costs need to be included in the revenue requirement for the purpose of rates. For plans that include Keeyask or Conawapa, sunk costs form part of the asset costs and are amortized over the life of the asset. For plans that exclude Keeyask or Conawapa, Manitoba Hydro has chosen to amortize the sunk costs over an 18-year period to 2031/32,[318] which would require approximately $90 million in annual revenue requirements associated with those plans over 18 years.[319]

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[316] Exhibit MH-180, p. 31.
[317] Transcript, p. 2883. See also, Exhibit MH -111, p. 38.
[318] Manitoba Hydro NFAT Submission, Chapter 11, p. 5.
[319] MIPUG/MH I-003c.

**Table 23 Exports as % of Total Revenues: 2013 vs. Updated Plans**

| | Plan 1 All Gas | Plan 2 K22/Gas | Plan 4 K19/Gas/250MW | Plan 5 K19/Gas/750MW | Plan 6 K19/Gas/750MW | Plan 14 (Preferred Development Plan) |
|---|---|---|---|---|---|---|
| 2013 Version | 8.6% | | 14.2% | | 13.8% | 17.3% |
| 2014 Version | 13.9% | 16.1% | 20.2% | 21.4% | 21.1% | 27.5% |
| Change | + 5.3% | | + 6.0% | | + 7.3% | + 10.2% |

Morrison Park concluded that the increases in revenues from exports for Manitoba Hydro across all of the updated plans result from lower domestic demand because of DSM Level 2 programs. The updated All Gas Plan is now as reliant on exports as the 2013 versions of Plans 4 and 6 were, while the updated versions of Plans 4 and 6 are now almost 50% more export-oriented, and projected to generate more revenue from exports than the 2013 version of the Preferred Development Plan. This indicates that ratepayer costs in all of the updated plans are inversely proportional to energy prices, and likely quite strongly inversely proportional.[326]

Commenting on the relationship between export risk and ratepayers, Morrison Park noted that "*structuring the Preferred Development Plan to be exposed to export price risks and export volume risks is not a traditional or typical way of constructing the economic relationship of a ratepayer to a monopoly utility provider.*"[327]

## 9.10.0 Other Metrics for Examining Rates and Revenues

### 9.10.1. Net Present Value Analysis

La Capra Associates reviewed the financial evaluation presented in Manitoba Hydro's 2013 NFAT Submission and calculated the Net Present Value of the projected annual rate increases, assuming a 7.05% nominal discount rate. The Net Present Value calculation provides a comparison of future rate increases to present rate increases. Manitoba Hydro did not provide this calculation in its financial analysis.

La Capra's Net Present Value analysis indicated that the Preferred Development Plan was not a clear winner in terms of having the lowest rate increases over the entire 50-year study period. Plan 4 (K19/Gas/250 MW) had lower rate increases and Plan 6 (K19/Gas/750 MW) showed lower rate increases over 35- and 40-year time periods. It was not until year 50 that the Preferred Development Plan moved into second place

[326] Exhibit MPA 3-1, p. 22.
[327] Transcript, p. 7392.

behind Plan 4. La Capra's findings were also consistent with another metric it calculated, namely the levelized cost of energy supplied.[328]

### 9.10.2. Impact of Rate Increases on Ratepayers

Manitoba Hydro's rate projections call for sustained even annual rate increases for at least 20 years. In its evidence before the Panel, Manitoba Hydro emphasized the intergenerational considerations associated with these increases. Manitoba Hydro's argument is essentially a "pay-it-forward" approach: today's generation of ratepayers enjoy low electricity rates and benefit from the investments of past generations in the hydro-electric system; therefore, it is now this generation's turn to pay higher rates so that future generations will reap the benefits of lower electricity rates.

The Preferred Development Plan and the All Gas Plan provide a good example of the intergenerational differences among the plans: with the Preferred Development Plan, today's ratepayers would pay higher rates, while the next generation would presumably benefit from lower rates; with the All Gas Plan, today's ratepayers would face rate increases that are less prolonged and severe than those of the Preferred Development Plan, but the next generation of ratepayers would face higher rates.

It is Manitoba Hydro's view that even with the proposed doubling of electricity rates over the next 20 years, Manitobans will still experience lower rates than many other Canadian jurisdictions, as electricity rates in those jurisdictions are increasing as well.[329]

Manitoba Hydro also told the Panel that rate increases in the order of 3.95% annually for the next seven to ten years would be required even if no new generation options were undertaken. The need to refurbish existing infrastructure and pay for Bipole III will drive these increases.[330]

### 9.10.3. Present Value of Customers' Revenues

The Panel was told that two critical elements for ratepayers are: (1) what the rates are expected to be over time; and (2) the expected total rate revenue that will be generated over time from domestic customers. Under Manitoba Hydro's current rate proposals, rates will more than double from current values.

Morrison Park constructed a financial model of Manitoba Hydro's electrical operations to assess the overall costs, benefits, and risks to ratepayers and other stakeholders in

[328] Exhibit LCA-13, p. 10A-60.
[329] Transcript, pp. 246-248.
[330] Transcript, p. 3031.

relation to Plan 1 (All Gas), Plan 4 (K19/Gas24/250 MW), Plan 6 (K19/Gas25/750 MW, WPS investment in transmission), Plan 12 (K19/C31/750 MW) and Plan 14 (Preferred Development Plan). Morrison Park's financial model calculates the annual payment that Manitoba ratepayers are presumed to make in the future under various assumptions and hydrological patterns using two different discount rates (6% and 10%) in order to compare streams of cash flow that fluctuate over time. Morrison Park applied Manitoba Hydro's probability weightings to each set of future conditions and blended the results based on these weightings to provide a calculation of average probability-weighted present value of domestic revenue.

With respect to the present value of ratepayer costs, the model demonstrated the sensitivity of the various plans to changes in the discount rate. The All Gas Plan and the Preferred Development Plan represent different rate patterns, with the All Gas Plan showing rate increases for the "first generation" of ratepayers that are less prolonged and not as high as those projected for the Preferred Development Plan. For the "second generation" of ratepayers the pattern reverses. According to Morrison Park, this is where the discount rate and the time value of money become apparent: if ratepayers would prefer to save now and pay later, they would have a high discount rate such as 10% or more and choose Plan 1 (All Gas). Conversely, if they were to focus on long-term benefits, they would have a low discount rate of 6% or less and choose the Plan 14 (Preferred Development Plan). Plans 4 and 6 fall in between Plan 1 and Plan 14.[331]

Overall, Morrison Park concluded, among other things, that Plans 4 and 6, which include Keeyask, a transmission interconnection, and natural gas plants, appear to rank better than the other plans, while Plans 14 and 12, which include Conawapa, are more costly to ratepayers than Plans 4 and 6, which include Keeyask but not Conawapa. Furthermore, Plan 4, with a 250 MW interconnection, outranks Plan 6, with a 750 MW interconnection. However, there is never more than a 1% variation between them.

Morrison Park updated its Net Present Value (ratepayer costs) analysis for the Panel. Ratepayers costs associated with various development plans were calculated at 6% and 10% discount rates over 20-, 30-, and 48-year periods. This analysis showed that the Preferred Development Plan had the highest ratepayer costs for all periods, although the gap narrowed significantly over time.

Morrison Park provided the total cost to ratepayers based on each 2013-updated plan, assuming annual rate increases of 3.8%. The Net Present Value total cost to ratepayers by plan is as follows[332]:

[331] Exhibit MPA-3, p. 46.
[332] Exhibit MPA 3-1, p.11.

*generational burdens, and the likely competitiveness of Manitoba electricity rates, will be very different depending on the choices made."*[342]

In its Final Argument, Manitoba Hydro commented on Morrison Park's model, noting that while there may be some benefit in using third party models for indicative long-term planning purposes, the models were not sufficiently robust to be considered reliable for short-term decision-making or rate-setting purposes. Manitoba Hydro was of the view that Morrison Park's model was sophisticated but had shortcomings that would limit its use.[343]

## 9.11.0 Bill Impacts

The Panel heard that customers' electricity bills matter more than rates. Each month, customers are focused on how much they have to pay rather than their electricity rate. The following Table provided by La Capra Associates shows the projected monthly bills for a residential customer using 750kWh of electricity at the estimated rate increases for the different plans. [344]

[342] Exhibit MPA 3-1, p.24.
[343] Exhibit MH-204, p. 197.
[344] Exhibit LCA-3-3, p. 9S-10.

**Table 27 La Capra Associates - Projected Monthly Residential Electricity Bill (Non-Electric Heat, 750 kWh/month)**

| | 2013 | 2032 | 2042 | 2052 | 2062 | NPV 2013-2062 |
|---|---|---|---|---|---|---|
| Plan 1 (All Gas) – Original 2013 Analysis | $60.96 | $115.72 | $119.21 | $143.32 | $168.50 | $1,218 |
| Plan 7 (Gas/C26) – Original 2013 Analysis | $60.96 | $124.69 | $109.96 | $128.65 | $142.89 | $1,222 |
| Plan 2 (K22/Gas) – Original 2013 Analysis | $60.96 | $117.05 | $115.46 | $134.58 | $146.44 | $1,209 |
| Plan 4 (K19/Gas/250MW) – Original 2013 Analysis | $60.96 | $115.58 | $112.42 | $131.55 | $148.33 | $1,196 |
| Plan 13 (K19/C25/250MW) – Original 2013 Analysis | $60.96 | $127.28 | $106.89 | $120.03 | $128.65 | $1,217 |
| Plan 12 (K19/C31/750MW) – Original 2013 Analysis | $60.96 | $123.43 | $110.55 | $121.69 | $128.94 | $1,214 |
| Plan 6 (K19/Gas/750MW) – Original 2013 Analysis | $60.96 | $117.16 | $112.24 | $131.86 | $148.10 | $1,202 |
| Plan 14 (PDP – K19/C25/750) – Original 2013 Analysis | $60.96 | $126.65 | $104.92 | $118.28 | $125.59 | $1,208 |
| Plan 14 – 2014 Update - With DSM Level 2 – Main Rate Submission | $60.96 | $129.00 | $104.93 | $110.16 | $113.28 | $1,196 |
| Plan 5 – 2014 Update - With DSM Level 2 – Main Rate Submission | $60.96 | $118.31 | $104.61 | $123.35 | $137.80 | $1,168 |
| Plan 1 – 2014 Update - With DSM Level 2 – Main Rate Submission | $60.96 | $111.11 | $110.78 | $137.97 | $158.89 | $1,171 |
| Plan 14 – 2014 Update - With DSM Level 2 and High Capital Cost – Main Rate Submission | $60.96 | $136.88 | $111.89 | $114.52 | $116.21 | $1,237 |

The above Table shows that by 2032, the various development plans all significantly impact customer bills.

### 9.11.1. Impact on Lower Income and Vulnerable Consumers

Many witnesses and presenters expressed concern about the proposed rate increases. Dr. Higgin, an expert witness on behalf of CAC, noted that there was considerable "intergenerational inequity" associated with the proposed increases since ratepayers would have to wait a long time to benefit from more modest rate increases while paying much higher electricity bills in the short term (2015 to 2025). He described the short-term impact on ratepayers' bills as "not acceptable", particularly for lower income and vulnerable consumers.[345] Dr. Higgin determined that vulnerable consumers[346] who use electricity to heat their dwellings would see a 46.5% increase in their electricity bills over 10 years (2013 to 2023) under the Preferred Development Plan compared to 39.9% under the All Gas plan, as depicted in the following Table.[347] Dr. Higgin defines

[345] Exhibit CAC-76, p. 10.
[346] Exhibit CAC-27, p. 55.
[347] Exhibit, CAC-27, p. 55.

vulnerable consumers as families (1-7 persons) with an income that meets the Statistics Canada After Tax LICO (2011 data).[348]

**Table 28 Dr. Higgin (CAC) Calculation - Bill Increases for Electric Heat, 2013 to 2023**

| Plan | 2013 Base yr. | 2013 | 2013 – 2023 Increase |
|---|---|---|---|
| K19ExpC25 750 MW | $1831 | $2683 | 46.5% ($852) |
| All Gas | $1831 | $2561 | 39.9% ($730) |

In their analysis of the impact of rate increases on low and non-low income households in Manitoba, two other CAC experts, Harvey Stevens and Dr. Wayne Simpson, concluded that rate increases of the scale proposed by Manitoba Hydro over the 2015 to 2032 period worsen the deficit already experienced by low income households and could move many near low income households into a deficit position.[349] Dr. Simpson noted that government transfers are one way to address the affordability of electricity rates.[350]

One witness from the joint CAC/MMF ratepayer panel told that Panel that electricity currently comprises 12% to 15% of her family's annual income.[351] CAC argued that the proposed rate increases would only further erode the already scarce dollars of lower income consumers and force them to cut back on other basic necessities.

### 9.11.2. Impact on Northern and Aboriginal Customers

Another concern brought to the Panel's attention was the large electricity bills paid by northern and aboriginal customers.

At one time, electricity customers paid different rates depending on where they lived in Manitoba. Northern customers were charged higher electricity rates than residents in the larger population centres such as Winnipeg and Brandon. This rate structure was abandoned several years ago when *The Manitoba Hydro Act* was amended to ensure that all customers in a specific rate class, including residential customers on the interconnected grid, paid the same electricity rates regardless of where they live in the province.[352]

[348] The Low income cut-off (LICO) represents a household income threshold where a family is likely to spend 20% or more of its income on food, shelter and clothing than the average family, leaving less income available for other expenses such as health, education, transportation and recreation. LICOs are calculated for families and communities of different sizes
[349] Exhibit CAC- 31, p. 3.
[350] Transcript, pp. 7865, 7867.
[351] Transcript, p. 7646.
[352] *The Manitoba Hydro Act*, C.C.S.M., c. H190. ss. 39(2.1), 39(2.2).

than-expected rate increases under certain conditions, such as higher capital costs, higher interest rates or lower exports revenues.

It is important to note that the risks borne by ratepayers differ significantly from risks borne by the Province. The Province receives relatively steady revenue flows from Manitoba Hydro by virtue primarily of the capital tax, water rentals, and the debt guarantee fee. As a result, the Province is not exposed to the downside risk faced by ratepayers.

MIPUG compared and contrasted the respective upside and downside faced by ratepayers and the Province of Manitoba under a P10 scenario (approximating the worst case) and a P90 scenario (approximating the best case), as compared to the reference scenario of the All Gas Plan:[404]

**Table 31 Incremental Benefit to Ratepayers and Government After 30 Years (Net Present Value Basis - $ millions)**

| | Plan 1 (All Gas) | | Plan 2 (K22/Gas) | | Plan 6 (K19/Gas/750MW) | | Plan 14 (K19/C26/750MW) | |
|---|---|---|---|---|---|---|---|---|
| | Ratepayer Benefit | Government Benefit | Ratepayer Benefit | Government Benefit | Ratepayer Benefit | Government Benefit | Ratepayer Benefit | Government Benefit |
| **Max (P90)** | +593 | +344 | +1,083 | +1,996 | +1,204 | +1,989 | +1,074 | +4,089 |
| **Reference** | **0** | **0** | **-164** | **+1,666** | **-138** | **+1,572** | **-1,031** | **+3,598** |
| **Min (P10)** | -586 | -384 | -1,376 | +1,300 | -1,524 | + 1,100 | -3,277 | +3,093 |

The Table shows that for all plans, after 30 years, ratepayers will receive a negative incremental benefit compared to the All Gas Plan at a reference scenario, while the Province of Manitoba will realize a positive benefit. Furthermore, at a P10 probability level, which approximates a worst-case scenario, incremental ratepayer benefits will be significantly negative, while the Province of Manitoba has no negative downside risk whatsoever. In MIPUG's view, there should be a rebalancing of the benefits realized by the Province from the new developments to offset the large increases in rates being sought from ratepayers and the exposure to risks borne by ratepayers.

## 10.3.0 Conclusions

All plans have risks that will have to be ultimately borne by ratepayers. The Preferred Development Plan has both the highest upside potential and greatest downside potential of all of the plans evaluated. However, the rate implications of the downside risks are material to ratepayers. The downside risk of Plan 6, which excludes

[404] Exhibit MIPUG-9, p. C-46.

Conawapa, is half that of Plan 14, which includes Conawapa. In light of this risk, adding Conawapa to Manitoba Hydro's generation fleet is not justified. Further spending on Conawapa should be terminated immediately.

The Panel recognizes that there is uncertainty associated with Manitoba Hydro achieving its forecast electricity export prices, owing to uncertainty with respect to the development of a carbon tax regime and projected demand in the MISO market. Manitoba Hydro's export pricing forecasts include a carbon premium at a future date, which is dependent on pending U.S. Federal and State mandates on clean energy. Whether these mandates will materialize remains uncertain.

Manitoba Hydro is currently experiencing historically low interest rates. However, there is a risk that higher, future interest rates when Keeyask and Conawapa come into service will result in higher annual debt servicing costs. These costs will ultimately have to be borne by ratepayers.

Manitoba Hydro's load forecast is subject to several short-term uncertainties, primarily whether the expected pipeline load will materialize. In the long term, the load forecast is subject to the risk of new technologies developing that will either significantly increase or decrease the demand for electricity. Manitoba Hydro has yet to address the potential risk and impacts of competing technologies and the implications of grid parity on its load forecast. There is further risk related to Manitoba Hydro's Demand Side Management efforts. Manitoba Hydro's Power Smart Plan target is new and untested. The Plan has yet to be formalized and executed. If Manitoba Hydro does not meet its targets, then capacity implications may arise with the arrival of new pipeline load requirements. However, advancing the Keeyask Project to 2019 mitigates this risk by providing additional surplus capacity in advance of domestic need.

Manitoba Hydro's capital cost estimates for its major generation and transmission projects could experience further increases, which could challenge Manitoba Hydro's financial well-being. It is the Panel's view that there remains a high degree of uncertainty as to whether the capital cost estimates for Keeyask and, in particular, Conawapa will escalate further. Should costs escalate to even higher levels, the economics of Manitoba Hydro's Preferred Development Plan would further deteriorate.

Manitoba Hydro continues to be subject to drought risk, specifically in the face of prolonged low water flows. The primary risk is not that Manitoba Hydro could not meet domestic demand, but rather that its financial situation would erode. This could require rate increases beyond what is currently budgeted. In the absence of such rate increases, there is a risk that the Province of Manitoba might have to step in to assume a portion of Manitoba Hydro's debt. From a reliability perspective, the 750 MW U.S. transmission interconnection would mitigate drought risk by providing enhanced import capacity.

However, the Panel recognizes that ratepayers will face significant rate increases in the early years as a result of these projects even without any downside risk materializing, while the Province of Manitoba will stand to benefit.

Manitoba Hydro, La Capra and Morrison Park identified that not all of these payments constitute net benefits or incremental revenues to the Government of Manitoba. While the debt guarantee fees are substantial, the amount of debt that government would be guaranteeing is also significant. Given that the provincial debt guarantee fee is provided in exchange for this guarantee, it could be considered a fee for service rather than a net benefit to the Manitoba government.

According to Morrison Park's analysis above, the incremental Net Present Value of water rentals and capital taxes to the Province of Plan 5 (K19/750MW) compared the All Gas Plan is approximately $876 million. Morrison Park also noted that the Preferred Development Plan provides the Province of Manitoba with the most revenue under all scenarios: across each revenue source individually, in total, and regardless of the discount rate calculation. This should be expected since the Preferred Development Plan uses the most water, the most capital, and the most debt of all the Plans.[443]

The benefits of additional revenue from Manitoba Hydro must be balanced against the higher costs to ratepayers that result from the Preferred Development Plan. It must also be balanced against the potential economic drag that may result from those higher rates (higher costs for a staple such as electricity is roughly the equivalent of a reduction in disposable income for individuals and businesses, which could result in lower tax revenue to the Government from sources other than Manitoba Hydro).[444] MIPUG, in its closing submission, agreed with this analysis.[445]

The nature and extent of benefits to the Government of Manitoba drew the attention of MIPUG. In MIPUG's view, the benefits from the Preferred Development Plan and other opportunity-based, export focused plans were "extraordinary." Mr. Turner, who provided a presentation on behalf of MIPUG, indicated that Industry would be paying $400 million more in rates over the next 20 years for the Preferred Development Plan compared to viable alternatives. He stated that this amount would not be available for Manitoba companies to invest in expansion, employees, community support, and other actions that would help the companies' competitiveness.[446]

## 11.7.0 Conclusions of the Panel

The Preferred Development Plan provides significant socio-economic benefits to the province, though not as high as originally stated. Manitoba Hydro initially assumed that Manitobans would fill 70% of construction jobs; however, in February 2014, Manitoba

443 Exhibit MPA 3-1, pp. 28-29.
444 Exhibit MPA 3-1, p. 28.
445 Exhibit MIPUG-28, p. 5. See also Transcript, pp. 7529-7530.
446 Transcript, p. 7208.

Hydro revised this figure down to 45%. The limited analysis undertaken by Manitoba Hydro of other Development Plans supports the view that the socio-economic benefits of hydro-based plans compare favourably with those based primarily on natural-gas thermal generation, largely due to the scale of the construction expenditures involved.

At this point in time, the Keeyask Project is associated with tangible socio-economic benefits that have been assured through the Joint Keeyask Development Agreement, already executed directly negotiated contracts, and a significant training effort that has been undertaken to date. While there will be some adverse effects in the communities, the Adverse Effects Agreements negotiated between each Keeyask Cree Nation and Manitoba Hydro largely address such effects. The Panel concludes that plans involving the Keeyask Project have higher benefits than plans in which Keeyask is not included. In contrast, Conawapa benefits are primarily speculative, as no agreements have been negotiated.

From an employment perspective, there is a legitimate concern that employment is subject to the cyclical nature of construction work. Compared to fossil-fueled generation, hydroelectric dams require fewer operating personnel. However, the overall benefits associated with the Keeyask Project significantly exceed the benefits of an All Gas Plan, and are to a large extent directed to northern Manitoba, in particular to affected First Nations communities. This is clear from the fact that despite dissenting voices in the community, the Keeyask Cree Nations have unequivocally stated that they support Keeyask being built.

The Panel is concerned that the full value of the socio-economic benefits of construction of Keeyask will not be realized without due attention to long-term training and further skills development for local workers, especially First Nations. Manitoba Hydro, together with the Keeyask Cree Nations, should facilitate ongoing professional development opportunities even after Keeyask construction has been completed.

The Panel is also of the view that Demand Side Management has the potential to provide significant employment benefits, which were not analyzed in the course of the NFAT Review. Chapter 5 notes the employment potential of DSM. DSM can and will play an important role in the creation of jobs in the future.

The Panel notes that under all scenarios, the Province of Manitoba will realize significant benefits from the development of the Keeyask Project through water rental fees and capital tax payments as further discussed in Chapter 8. The Government of Manitoba could use a portion of the incremental capital tax and water rental fees from the development of the Keeyask Project to mitigate the impact of rate increases on lower income, northern and aboriginal communities.

5. ***The Panel recommends that the Government of Manitoba direct Manitoba Hydro to immediately cease any and all expenditures associated with the design, implementation, and future development of the Conawapa Project.***

## Demand Side Management Plans and Programs

During the NFAT Review hearings, the Panel heard that Demand Side Management initiatives were "game changers." The Panel learned that Demand Side Management can have a profound impact on the need for, and timing of, new energy resources. According to its 2014 Supplementary Power Smart Plan, Manitoba Hydro can achieve 1,136 MW and 3,978 GWh of electricity savings by 2028/29. This would amount to more than 80% of the net system capacity addition from the proposed Conawapa Project.

Successful Demand Side Management initiatives are based on ambitious and achievable targets. In recent years and on an annual basis as a percentage of total demand, Manitoba Hydro's DSM savings have declined to approximately 0.4%, well below the 1.5% to 2% levels seen in many other jurisdictions. Demand Side Management savings in the order of 1.5% (including codes and standards) are achievable and economic.

Manitoba Hydro was formerly recognized as a leader in DSM but has since been surpassed by a number of jurisdictions. The Panel is concerned that the full potential for Demand Side Management will not be realized if the responsibility for Demand Side Management remains within Manitoba Hydro. Commitment, independent action and external monitoring of performance are the demonstrated and proven ingredients of successful DSM programs. Interveners encouraged the Panel to take these steps.

6. ***The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.***

7. ***The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.***

8. ***The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.***

9. ***The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.***

10. ***The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro continue to address the barriers to lower income customer participation in its Demand Side Management programs.***

11. ***The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating.***

## Rates and Ratepayer Impacts

Manitoba Hydro will have to invest in replacing aging infrastructure and in building Bipole III. This will result in increasing electricity rates over the coming decade. The construction of new generation and associated transmission facilities will add to and prolong these rate increases. Furthermore, construction costs will most likely grow and revenue projections may not be achieved. This gap between rising costs and unrealized revenues will be borne by ratepayers.

Given the length of time projected for these rate increases and their magnitude, especially in the early years, the Panel is concerned about intergenerational fairness and the impact on vulnerable residents and communities. Lower income consumers, particularly those in northern and aboriginal communities where energy choices are limited or non-existent, will especially feel this impact.

The Government of Manitoba will receive significant revenues from incremental capital taxes and water rental fees from the development of the Keeyask Project. It would be reasonable for the Government of Manitoba to use some or all of the incremental revenue it will realize from the Keeyask Project to mitigate adverse rate impacts on vulnerable consumers. Furthermore, Manitoba Hydro should take internal actions to moderate rate increases.

12. ***The Panel recommends that the Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project to be used to mitigate the impact of rate increases on lower income consumers, northern and aboriginal communities.***

13. ***The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases.***

14. ***The Panel recommends that Manitoba Hydro implement cost containment measures to moderate its proposed electricity rate increases.***

## Actions in Support of a Clean Energy Future

As a result of the NFAT Review, the Panel concludes that Manitoba requires a new commitment to a clean energy future. The recommendation to proceed with the Keeyask Project and the 750 MW Transmission Interconnection augments Manitoba's hydropower foundation. It is now time to determine and build a more diversified resource portfolio. To achieve this future, Manitoba must invest in new planning tools. Integrated resource planning is a best practice in many jurisdictions. The Panel concludes that an integrated resource planning process is required to determine what supply and demand side resource mix is in the best interests of Manitobans.

15. ***The Panel recommends that integrated resource planning become a cornerstone of a new clean energy strategy for the Province of Manitoba.***

16. ***The Panel recommends that the Government of Manitoba not approve the construction of any generating facilities, nor approve the beginning of the required infrastructure work for any generation facility, beyond the Keeyask Project, unless such facilities are justified through an integrated resource planning process. The integrated resource planning process must include public consultation.***