Q. Please provide copies of Mr. C. F Osler's expert testimony before the Yukon Public Utilities Board on planning capital projects (1992), on electricity costing and rates related to rate applications by Yukon Energy Corporation in 1997 and 1998 and before the Manitoba Public Utilities Board in the Manitoba Hydro electricity rate hearing of 1998.

A. Mr. Osler participated as an expert in the Yukon Capital Project proceeding (1992) and rate hearings (1997 and 1998) as a part of a panel of witness called by the utility. No evidence was prepared under separate cover under Mr. Osler's name. Mr. Osler's evidence in those proceedings consists only of transcripts which are voluminous and not attached to this response.

Mr. Osler's expert pre-filed testimony in the Manitoba Hydro rate hearing of 1998 is attached. That proceeding was of a limited scope and addressed only a "curtailable" rate offering of Manitoba Hydro – a comparable rate to the Interruptible B rate in Newfoundland (except that it is offered on a long-term basis to all industrial customers). Mr. Osler appeared as an expert for the industrial customer group (Manitoba Industrial Power Users Group or MIPUG) in that proceeding.

INTERGROUP CONSULTANTS LTD.

September 4, 1998
P.331.5

DELIVERED

Mr. G.O. Barron
Public Utilities Board of Manitoba
2nd Floor – 280 Smith
Winnipeg, MB R3C 1K2

Dear Sir:

RE: Manitoba Hydro
DFH/SESS Approval Application
Spot Market Replacement Energy Rates Application
Curtailable Rates Application

Please find attached nine copies of the pre-filed testimony of Cam Osler filed on behalf of the Manitoba Industrial Powers Users Group concerning the above matter.

This evidence is also being sent to each registered Intervenor.

Sincerely,

INTERGROUP CONSULTANTS LTD.

Cam Osler
President

Enclosure

cc: P. Ramage, Manitoba Hydro Law Department
Registered Intervenors

MH #1

PREFILED TESTIMONY OF
C. F. OSLER
IN REGARD TO MANITOBA HYDRO
APPLICATION FOR APPROVAL OF THE
CURTAILABLE SERVICE PROGRAM
DFH/SESS REVISIONS
AND
ISE/DFM SPOT MARKET ENERGY PRICES

submitted to

THE PUBLIC UTILITIES BOARD OF MANITOBA

on behalf of the

MANITOBA INDUSTRIAL POWER USERS GROUP

Prepared by InterGroup consultants Ltd.
604-283 Portage Avenue
Winnipeg, MB R3B 2B5

September 1998

PREFILED TESTIMONY OF C. OSLER

Introduction

This testimony has been prepared for the Manitoba Industrial Power Users Group (MIPUG) by InterGroup Consultants Ltd. (InterGroup) under the direction of Mr. C. F. Osler. It addresses specific issues for the public hearing to be held by The Public Utilities Board of Manitoba (PUB) in response to an application by Manitoba Hydro (Hydro) for approval of the Curtailable Service Program (CSP) and various other matters (the Application).

Mr. Osler has appeared before the Board during review of Hydro rates on several occasions from 1988 onwards as well as during the 1990 review of Major Capital Projects. He has testified before the Ontario Energy Board, the National Energy Board, the Yukon Utilities Board, the Saskatchewan Public Utilities Regulating commission, and various other government boards and commissions of enquiry.

Mr. Osler's testimony focuses solely on specific issues related to calculation of the Reference Discount for the CSP.

Overview of Reference Discount calculation issues

The background on Hydro's calculation of the Reference Discount for the CSP is set out in the filed evidence as an attachment to the Report on the Experimental Service Program (see ExpCurt pages 23 to 28). The procedures and assumptions described in that attachment have been reviewed in the context of Hydro's earlier reports to the Board assessing the Reference Discount applicable to CSP rates approved previously by the Board.

Based on this review, it is apparent that Hydro has modified various procedures in its latest calculations compared with its earlier calculations. The following issues in particular were identified for more detailed examination:

1. **12% discount issue:** Hydro's latest calculations assume that marginal capacity costs used to calculate the Reference Discount should be discounted by 12%, with respect to both generation deferral (winter) capacity marginal costs and generation production (summer) capacity marginal costs. Hydro states that the 12% reduction to the winter capacity cost is required to account for capacity reserve because the CSP is being evaluated "as an equivalent generator" (ExpCurt-24), and that the 12% reduction to the summer capacity cost is required because "Manitoba Hydro must carry the reserve whenever a capacity sale

is made to MAPP entities" (ExpCurt-25). No similar capacity reserve adjustments were applied in the 1993 and 1995 evaluations of capacity benefits for the Reference Discount calculation.

2. **Winter capacity cost issue:** Hydro's latest calculations change the weighting between energy and capacity for calculating the 1997 marginal cost of generation deferral (winter) capacity. In all previous calculations reviewed by the PUB, energy and capacity were assumed to be equally important in deferring generation. The 1997 Hydro analysis of marginal cost has revised this assumption and assumes that firm energy should be given a weight of 2/3 and firm capacity a weight of 1/3 in terms of ability to defer generation. Hydro states that this change in weighting between energy and capacity was made "based on experience since 1993 which gives increased confidence in the expectation that energy will continue to be the dominant factor affecting generation deferral" (ExpCurt-23).

3. **Other adjustments:** The following additional procedural adjustments were identified with respect to the calculation of the Reference Discount in the current Application compared with Hydro's procedures in its earlier filings to the Board:

    - **winter capacity**: The only other adjustment was to reduce the marginal capacity cost by 4% to account for distribution losses between the customer meter level and the large industrial customer level.
    - **summer capacity:** The value for summer capacity has changed to reflect changes in the export market and changes in the CSP terms. Hydro has increased from 60% to 80% the adjustment factor used to reduce the subscribed capacity value for the purpose of the CSP Reference Discount to reflect various factors (see ExpCurt-26 and the response to MIPUG/MH-9(h)).

In reviewing this matter, the following documents plus other related material have been reviewed in addition to the Application and the Hydro responses to interrogatories:

- 1990 Avoided Cost Report (GP 90-1) which was first tabled in the Capital Hearing
- the 1993 Report (GP 93-2) which updated GP 90-1, and was reviewed in the 1994 Rate Application hearing
- the 1995 Report (SPED 95-2) which updated GP 93-2 and was reviewed in the 1996/97 Rate Application.

Review of the 12% discount issue for winter capacity

The Curtailable load program is a DSM or load-related type of initiative. This point has been recognized since the outset in evaluating curtailable rates. It has recently been confirmed by an arbitrator (see ExpCurt-22, where the arbitrator dealing with issues between Hydro and Winnipeg Hydro found that the Curtailable Rate Program is a DSM Program). Hydro has also confirmed that the curtailable rates program "was designed as a DSM load management program" (see response to CAC-MSOS/MH-7)

The fact that CSP is a DSM load management program means that it differs fundamentally from an "incremental generation improvement" initiative. Without the CSP, the applicable peak capacity loads would be assumed to be transferred back to existing firm load and Hydro's planning would need to proceed on the basis that it must accommodate all of this load capacity requirement (and related transmission loss requirement) that is coincident with the system peak *plus* provide 12% reserve generation capacity on top of the customer peak and transmission loss requirement. The Curtailable load program, as with other DSM load management programs, presumes certainty that the identified forecast load will be curtailed fully as and when required, i.e., there is no performance risk to be assessed similar to that applicable for any generation option. In this regard, it does not matter whether the load is curtailed voluntarily by the customer (in response to the customer's market conditions) or in response to a curtailment direction from Hydro - the net result is the assurance that Hydro does not need to plan on the basis that this load is to be part of Hydro's firm peak capacity requirement. Based on these DSM-related principles, the full Generation Deferral portion of the Avoided Capacity cost should be recognized to be applicable when assessing the benefits of this DSM initiative. This view is consistent with all of the relevant evidence from past PUB hearings assessing DSM program benefits related to capacity savings. Further, Hydro has confirmed that the evaluation today of other DSM programs "does not reduce capacity for reserve requirements" (see response to MIPUG/MH-8(c), page 25).

In contrast, the 12% reserve for capacity is recognized to be applicable when assessing incremental generation supply options. The 12% reserve was addressed most clearly in GP 90-1 where it was noted that the **Generation Deferral** portion of the Avoided Capacity Cost assumes "perfectly reliable power resources". It was further noted (page 6.1) that for resources which may not be available when required, an "appropriate capacity reserve is required". The 12% reserve was noted to be required for "incremental generation improvements".

Hydro's response to MIPUG/MH-8 acknowledges the change in method since 1993 on this matter, and states that the earlier Reference Discount analysis did not include the 12% reduction "due to an error of omission rather than a conscious decision to exclude the reduction". Hydro states as follows (MIPUG/MH-8(c)):

"Since the beginning of the program in 1993, it was always assumed that it is appropriate to evaluate the Curtailable Service Program as an equivalent generator on the Manitoba Hydro system. This is assumed because CSP capacity behaves like a generator that can be dispatched rather than a discrete reduction in firm load. Manitoba Hydro's capacity planning criterion requires that a reserve of 12% must be carried on all firm generation designated to meet firm load".

"It is confirmed that the evaluation of other DSM programs does not reduce capacity for reserve requirements. These DSM programs result in firm load reductions which are not similar to dispatchable resources such as a generator which has uncertainty of supply. The CSP capacity is judged to be more similar to a generator than a firm load reduction because of the following constraints which result in uncertainty of supply during critical periods:

1 Notice period before curtailment.
2. Maximum duration per curtailment.
3. Maximum curtailment duration per day.
4. Maximum number of hours of curtailment per year.
5. Maximum number of hours of curtailment over entire program duration."

Hydro's comments, however, appear to confuse issues related to the basic DSM value of CSP versus practical issues relating to the assessment of each CSP option as well as what occurs when curtailments are actually "dispatched" by Hydro.

Actual discounts applied to *specific* curtailable load programs have always considered the differences in effectiveness between the curtailed load resource versus a new generator resource. For this reason, by way of example, the Option A curtailable program receives a discount at only 70% of the Reference Discount. Further, the Reference Discount calculation itself has also discounted Hydro's marginal capacity costs to reflect similar differences, e.g., only 80% of Generation Deferral Capacity marginal costs have been included in the Reference Discount since the outset of the CSP. Hydro has reaffirmed that this 80% factor is "an overall qualitative judgement on the value of the Option 'AE" program relative to an equivalent generator", and that this judgement "considers the limitations of the terms and conditions of the Curtailment Service Programs, the logistics of carrying out the curtailments, and Manitoba Hydro ability to predict the timing of the annual peak"(MIPUG/MH-8(d)). In essence, Hydro confirms that all of the factors used to explain the 12% discount have been used to explain the 80% reduction which has already considered the lesser flexibility for CSP versus an equivalent generator and the extent to which the curtailable capacity may not be available over the system peak.

In principle, however, the curtailable program allows Hydro to be certain that a capacity load which otherwise could be required at a time of system capacity stress will be curtailed, i.e., will not be on the system (whether due to prior elective curtailment by the customer or due to subsequent curtailment in response to MH's notice). Hydro is presumed to have designed the CSP to give it sufficient flexibility so that it can always hold adequate CSP capability (in relation to the specific programs with each customer) to address its requirements at the period when system peakis likely to occur. On the basis of a DSM initiative, it does not matter whether or not the load is being used by the customer at the time when the system operator calls for a curtailment. Further, the curtailment program provides certainty relative to some other types of DSM. Finally, as with other DSM programs, CSP allows Hydro to avoid both the generation capacity and the 12% reserve related to that capacity.

In summary, the 1993 and 1995 evaluations of winter capacity benefits were correct in not adjusting marginal or avoided capacity costs by the 12% reserve margin. Accordingly, there is no basis for introducing the 12% reserve discount as a new reduction in 1997 on top of other reductions already used when calculating the Reference Discount.

Review of the 12% reserve issue for summer capacity

The issue of a 12% reserve for summer capacity differs from the 12% reserve for winter capacity. Whereas winter capacity values relate to deferral of new generation required in the future, summer capacity values relate entirely to short-term firm capacity sales rather than long-term generation costs. The issue for summer capacity values is to assess the full incremental benefit that Hydro is able to secure from access to CSP loads that allow additional short-term month-to-month firm capacity export sales.

Hydro has confirmed that no 12% deduction for reserve capacity was made in the 1993 Reference Discount calculation related to summer capacity values (MIPUG/MH-9(a)).

In response to MIPUG/MH-9(d), Hydro has stated its rationale for reducing the summer capacity value by 12% for the purpose of the Reference Discount calculation as follows:

> "Manitoba Hydro must carry a reserve of at least 10% for capacity sales to MAPP in order to meet the Reserve Capacity Obligation (RCO) as specifies in the MAPP Agreement. For example, if 100 MW of capacity is made available through the CSP, Manitoba Hydro must maintain a reserve of 10% to meet the RCO requirement of MAPP. Therefore, the revenue would occur from only 90.9 MW (100/1.1) of capacity because the remaining 9.1 MW must be retained for reserve.

See MH/MIPUG #3 example
See PUB/MIPUG #3

> "The RCO for capacity generated by thermal resources is 15%. Manitoba Hydro has used a capacity reserve of 12% in the Reference Discount analysis because it is consistent with its own reserve requirement and consistent with the generation deferral component."

percentage deviation reasonable added info needed

The ability to carry out such short-term summer capacity sales clearly augments Manitoba Hydro's revenues by the full value of the price offered. The only issue is whether Hydro's revenue is in fact augmented by 100% of the CSP load times the relevant export capacity sale value. Hydro's position suggests that it receives no more than 90.9% of the export value due to a MAPP requirement to carry a reserve on all such sales.

Based on the information available at this time, it is not completely clear why Hydro is unable in practice to realize 100% revenue benefit on its CSP induced short-term exports. This matter was not raised in the past, and seems in this instance to be tied to the new analysis relating to the generation deferral component. Further, Hydro has separately noted that the small load of a curtailable customer "is within the uncertainty range of capacity reserves" (CAC-MSOS/MH-(c)). Finally, it is not clear whether Hydro has any discretion in responding to the MAPP requirement (versus an automatic reduction in the amount of any short-term capacity sale), or whether there are less expensive options available to Hydro to meet this requirement.

In summary, the reasonableness of the 12% reduction for summer capacity sales depends on confirmation as to what Hydro in fact realizes from CSP-related summer capacity sales.

PUB/MIPUG #4

Winter capacity cost issue

The latest 1997 marginal cost analysis for Generation Deferral (winter) has for the first time changed the capacity/energy ratio from 50:50 to 1/3:2/3.

a) magnitude dollar impact
b) basis for average (vs chosen)
c) other ways to moderate the impact

It is stated that more emphasis is placed on energy today because new generation is currently driven by firm energy requirements as opposed to firm capacity requirements. IFF97-1, for example, reports (page 12) that the timing of new plant is driven by a forecast shortage of energy in 2016 as sufficient capacity exist until 2019. However, the relevance of firm energy requirements in this context has been generally recognized since GP 90-1, and it has been known that the relative importance of capacity versus energy could fluctuate somewhat from time to time in the future in response to changing conditions. The 50:50 rate reflected this situation, and it is difficult now to support significant changes in this ratio on the grounds suggested. Without more information, for example, it is not possible to assess the extent to which the latest forecasts reflect the expiry of existing export/import contracts and the relative impacts that such arrangements have on the calculation of energy versus capacity shortages in future years.

Hydro has explained that this change "is consistent with all resource planning analyses which use marginal cost" (MIPUG/MH-8(b)). Accordingly, it does not seem useful to discuss this matter at any length in the present hearing. Such long term planning and policy matters may be better addressed in a future rate hearing context. MH/MIPUG -2

Dealing solely with the curtailable rates program extension, it would seem reasonable to discuss how the impacts of this specific change might be moderated for the CSP over the next five years. An average of the past and present approaches, for example, would reflect the fact that the CSP values should not jump up and down on such matters in a situation where there is no effective opportunity to review fully the overall planning situation and analysis.

Other adjustments to the reference discount calculations

Review of the other adjustments noted earlier indicates no basis for further discussion at this time, other than to note that there are several factors contributing to enhanced summer export capacity values related to CSP. It is difficult to assess from the available information the extent to which all of these favourable changes are fully reflected in the new Reference Discount calculations.

Hydro has separately acknowledged that an additional benefit of the CSP program is increased system reliability, and this benefit has not been directly evaluated in the generation deferral component (CAC-MSOS/MH-2(c)).

Implications to Reference Discount Values

Tables 1 and 2 attached summarize calculations separately for the winter and summer capacity components involved in the Reference Discount amount. Each table indicates the implication of changes to these calculations as reviewed above. The overall Reference Discount is the sum of the winter and summer values.

This information is provided to indicate the impact of the recent changes. The following further adjustments are proposed for consideration today:

a) removal of the 12% discount for both winter and summer calculations; and
b) averaging of the 1993 and 1998 approaches for calculating the winter capacity value (as regards the energy/capacity allocation of deferral value).

See MH/MIPUG 1(b) ~~#~~ Tables & PUB/MIPUG 1 and 2

P:\P331\331-5\PREF-TST\PREFILED. September 4, 1998

Table 1: Curtailable Service Program - Reference Discount Re: Generation Deferral (Winter) Marginal Cost

	1993 analysis initial program	1998 update 1993 assumptions	1998 update revised assumptions
Manitoba Hydro Marginal Cost calculation ($/kw/year)			
Basic value of deferral ($/MW.h)	5.30	4.90	4.90
Assigned to capacity ($/kw/yr)			
at 50:50 capacity:energy	13.20	12.67	
at 33:67 capacity:energy			8.47
Other adjustments:			
remove distribution loss at 4%	-	-	(0.33)
remove assumed generation reserve at 12%	-	-	(0.87)
Curtailable equivalence to generator at 80%	(2.64)	(2.53)	(1.45)
Reference Discount re: Generation Deferral component	**10.56**	**10.14**	**5.82**
	(1993$)	(1996$)	(1996$)
Value for 1998-2002 Five Year Program ($/kw/year):			
Option 1: current 1998 dollar value (assume 2% inflation from 1996)		**10.55**	**6.05**
(use this option if adjust each year, after 1998, for actual inflation)			
Option 2: levelized dollar value for five years (assume 2% inflation and 8% discount rate)		**10.94**	**6.28**
(use this option if Reference Discount not adjusted during 5 year program)			

	Reference Discount (Base)	Five Year Program values (Reference Discount $/kW/yr) 1998/99	1999/00	2000/01	2001/02	2002/03
Option 1: current 1998 dollar value						
Manitoba Hydro 1993 assumptions	**10.55**	10.55	10.76	10.97	11.19	11.41
Manitoba Hydro 1998 assumptions	**6.05**	6.05	6.17	6.30	6.42	6.55
Average of 1993 & 1998 approaches	**8.30**	8.30	8.46	8.63	8.81	8.98
assumed inflation each year		*0.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
Option 2: levelized dollar value for five years						
Manitoba Hydro 1993 assumptions	**10.94**	10.94	10.94	10.94	10.94	10.94
Manitoba Hydro 1998 assumptions	**6.28**	6.28	6.28	6.28	6.28	6.28
Average of 1993 & 1998 approaches	**8.61**	8.61	8.61	8.61	8.61	8.61

Table 2: Curtailable Service Program - Reference Discount Re: Generation Production (Summer) Marginal Cost

	1998 update for years after 1998	
	without 12% reserve	with 12% reserve
Manitoba Hydro Marginal Cost calculation ($/kw/year)		
Basic value of short term firm export (US$/MW/month for 6 months)	2,750	2,750
exchange rate assumed (C$/US$)	1.25	1.25
Basic value of short term firm export (C$/MW/month for 6 months)	3,438	3,438
Basic value per Kw/year [(value per month x 6)/1000]	20.63	20.63
Adjustments:		
remove assumed generation reserve at 12%	-	(2.21)
Curtailable equivalence to generator at 80%	(4.13)	(3.68)
Reference Discount re: Generation Deferral component	**16.50**	**14.73**
	(1997$)	(1997$)
Value for 1998-2002 Five Year Program ($/kw/year):		
Option 1: current 1998 dollar value ($US)	**13.46**	**12.02**
(use this option if adjust each year, after 1998, for actual inflation)		
Option 2: levelized dollar value for five years ($C) (assume 2% inflation and 8% discount rate)	**17.46**	**15.59**
(use this option if Reference Discount not adjusted during 5 year program)		

	Reference Discount (Base)		Five Year Program values (Reference Discount C$/kW/yr)				
	(1998 only)	(after 1998)	1998/99	1999/00	2000/01	2001/02	2002/03
Option 1: current 1998 dollar value ($US)							
Without 12% reserve	**11.26**	**13.46**	16.89	20.60	20.73	20.72	20.84
With 12% reserve	**10.05**	**12.02**	15.08	18.39	18.51	18.50	18.61
Average of the above	**10.66**	**12.74**	15.99	19.50	19.62	19.61	19.72
assumed inflation each year			*0.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*
assumed exchange rate each year			*1.5*	*1.5*	*1.48*	*1.450*	*1.43*
Option 2: levelized dollar value for five years with Manitoba Hydro exchange rate forecast							
Without 12% reserve		**17.46**	17.46	17.46	17.46	17.46	17.46
With 12% reserve		**15.59**	15.59	15.59	15.59	15.59	15.59
Average of the above		**16.53**	16.53	16.53	16.53	16.53	16.53

MH/MIPUG-1(a)

QUESTION

Your evidence discusses several questions related to determination of the Reference Discount and offers an alternative determination

a) Are you recommending that your alternative calculation be adopted as the Reference Discount?

ANSWER

There is no alternative calculation proposed in the Pre-Filed Testimony. The calculation method in Option 1, as set out in Tables 1 and 2, is identical to that proposed by Manitoba Hydro in the present application. The only variation is in the ratios and percentages used within this calculation approach.

Option 2 was presented in the tables only to indicate what would apply if the levelized dollar value approach had been retained (as per Manitoba Hydro's Attachment Exp Curt). Option 2 is not proposed.

MH/MIPUG-1(b)

QUESTION

b) If the answer to a) is "yes", please indicate the values you would substitute for A and B in the equations on p. CSP-1 in Note 1.

ANSWER

As noted on the attached tables (Pre-filed Testimony Information Request Tables 1 and 2), the values would be amended from those proposed by Manitoba Hydro in the present application by removing the 12% reduction for Generation Deferral (winter), the 12% reduction for Generation Production (summer), and by modifying the ratio of capacity:energy related to generation deferral to an average of the 1/3:2/3 approach and the 50/50 approach.

The attached tables are derived from Attachment Exp Curt-1 and the Addendum at Exp Curt-8 and 9 in the current application (adapted to include changes to US$ Exchange Rate and Inflation adjustments) and are updated from Table 1 and Table 2 in the pre-filed testimony to outline the specific values proposed by MIPUG. Option 1 on these tables demonstrates the approach which allows for annual corrections for inflation (as proposed by Manitoba Hydro). A detailed description of the source data and calculations present in the tables are included in PUB/MIPUG-1 and PUB/MIPUG-2.

These modifications result in a value for winter Generation Deferral (A) equal to $8.46 per year or $0.70 per month (Table 1) and summer Generation Production (B) equal to $11.26/year or $0.94/month in 1998/1999 and $13.46/year or $1.12/month for subsequent years (Table 2).

More specifically, these modifications will result in the following values for A and B in the equations on page CSP-1 in Note 1.

1) For 1998/99 A = $0.70 (rather than $0.50 on page CSP-1)
B = $0.94 (rather than $0.84 on page CSP-1).

2) For subsequent years: A = $0.70 (rather than $0.50 on page CSP-1)
B = $1.12 (rather than $1.00 on page CSP-1).

Prefiled Testimony Information Request MH/MIPUG-1(b)
Table 1: Curtailable Service Program - Reference Discount Re: Generation Deferral (Winter) Marginal Cost

COLUMN	1 1993 analysis Initial program	2 1998 update 1993 assumptions	3 1998 update proposed approach MIPUG	4 1998 update revised assumptions Manitoba Hydro
Manitoba Hydro Marginal Cost calculation ($/kw/year)				
Basic value of deferral ($/MW.h)	5.30	4.90	4.90	4.90
Assigned to capacity ($/kw/yr)				
at 50:50 capacity:energy	13.20	12.67		
at 33:67 capacity:energy				8.47
at average of two approaches			10.57	
Other adjustments:				
remove distribution loss at 4%	-	-	(0.41)	(0.33)
remove assumed generation reserve at 12%	-	-	-	(0.87)
Curtailable equivalence to generator at 80%	(2.64)	(2.53)	(2.11)	(1.45)
Reference Discount re: Generation Deferral component	**10.56**	**10.14**	**8.05**	**5.82**
	(1993$)	(1996$)	(1996$)	(1996$)
Value for 1998-2002 Five Year Program ($/kw/year):				
Option 1: current 1998 dollar value (assume 2% inflation from 1996)		**10.55**	**8.37**	**6.05**
(use this option if adjust each year, after 1998, for actual inflation)				
Option 2: levelized dollar value for five years (assume 2% inflation and 8% discount rate)		**10.94**	**8.69**	**6.28**
(use this option if Reference Discount not adjusted during 5 year program)				

	Reference Discount (Base)	Five Year Program values (Reference Discount $/kW/yr) 1998/99	1999/00	2000/01	2001/02	2002/03	Monthly Value of A (A+Bx Reference Discount Equation)
Option 1: current 1998 dollar value							
Manitoba Hydro 1993 assumptions	**10.55**	10.55	10.76	10.97	11.19	11.41	$0.88
Manitoba Hydro 1998 assumptions	**6.05**	6.05	6.17	6.30	6.42	6.55	$0.50
MIPUG Proposal	**8.37**	8.37	8.54	8.71	8.89	9.07	$0.70
assumed inflation each year		*0.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*	
Option 2: levelized dollar value for five years							
Manitoba Hydro 1993 assumptions	**10.94**	10.94	10.94	10.94	10.94	10.94	$0.91
Manitoba Hydro 1998 assumptions	**6.28**	6.28	6.28	6.28	6.28	6.28	$0.52
MIPUG Proposal	**8.69**	8.69	8.69	8.69	8.69	8.69	$0.72

Prefiled Testimony Information Request MH/MIPUG-1(b)
Table 2: Curtailable Service Program - Reference Discount Re: Generation Production (Summer) Marginal Cost

	1998 update for years after 1998: without 12% reserve	1998 update for years after 1998: with 12% reserve
Manitoba Hydro Marginal Cost calculation ($/kw/year)		
Basic value of short term firm export (US$/MW/month for 6 months)	2,750	2,750
Basic value per Kw/year [(value per month x 6)/1000]	16.50	16.50
Adjustments:		
remove assumed generation reserve at 12%	-	(1.77)
Curtailable equivalence to generator at 80%	(3.30)	(2.95)
Reference Discount re: Generation Deferral component	**13.20**	**11.79**
	(1997$US)	(1997$US)
Value for 1998-2003 Five Year Program ($/kw/year):		
Option 1: current 1998 dollar value ($US)	**13.46**	**12.02**
(use this option if adjust each year, after 1998, for actual inflation)		
Option 2: levelized dollar value for five years ($C) (assume 2% inflation and 8% discount rate)	**17.46**	**15.59**
(use this option if Reference Discount not adjusted during 5 year program)		

	Reference Discount (Base) (1998-1999)	Reference Discount (Base) (subsequent)	Five Year Program values (Reference Discount C$/kW/yr) 1998/99	1999/00	2000/01	2001/02	2002/03	Monthly Value of B, A+Bx Ref. Disc. Equation (1998-1999)	(subsequent)
Option 1: current 1998 dollar value ($US)									
Without 12% reserve	**11.26**	**13.46**	16.89	20.60	20.73	20.72	20.84	$0.94	$1.12
With 12% reserve	**10.05**	**12.02**	15.08	18.39	18.51	18.50	18.61	$0.84	$1.00
assumed inflation adjustment each year			*0.0%*	*2.0%*	*2.0%*	*2.0%*	*2.0%*		
assumed exchange rate each year			*1.5*	*1.5*	*1.48*	*1.45*	*1.43*		
Option 2: levelized dollar value for five years with Manitoba Hydro exchange rate forecast									
Without 12% reserve		**17.46**	17.46	17.46	17.46	17.46	17.46	$1.46	$1.46
With 12% reserve		**15.59**	15.59	15.59	15.59	15.59	15.59	$1.30	$1.30

7.88

MH/MIPUG-2

QUESTION

With respect to the assignment of benefits of Generation Deferral. Your evidence (p.7) notes "it does not seem useful to discuss this matter at any length in the present hearing." Please explain why this is so given your concern with its impact on the Reference Discount?

ANSWER

Despite concern over the obvious impact on the Reference Discount, Hydro has not approached the present hearing with the view that the underlying cost and forecast changes would be subject to review at this time. Accordingly, we do not see how it is likely to be useful to discuss this matter at any length in the present hearing. This observation is the only rationale for MIPUG suggesting averaging of alternative impacts rather than proposing some other solution at this time. Alternatively, in light of the lack of evidence to justify the proposed change in Hydro's earlier methods, it would be appropriate to return to the earlier 50:50 assignment.

Additional comments on the substantive issues are provided below.

BASIC CHANGE RATIONALE AND EVIDENCE PROVIDED

Manitoba Hydro has changed the capacity:energy ratio for calculating the Generation Deferral portion of the reference discount from 50:50 to 1/3:2/3. This change is based on "increased confidence in the expectation that energy will continue to be the dominant factor affecting generation deferral" (ExpCurt-23) and is "consistent with all resource planning analyses which use marginal cost" (MIPUG/MH-8(b)). These updated resource planning analyses have not been subjected to a General Rate Application hearing. The relevant updated avoided cost reports have not been provided to MIPUG or the PUB, let alone subjected to any hearing before the Board. Updated supply/demand generation forecasts have also not been provided on any basis that would facilitate detailed comparison with earlier evidence filed in each rate hearing during the last many years.

FACTORS RELEVANT TO THE ISSUE

The determination of the dominant factors affecting generation deferral is based on long-term load projections and forecasts (which are in turn based on long-term projections of such factors as DSM, import and export quantities, generator retirement schedules, consumer load growth, hydrologic flow scenarios, and many other factors). These projections and forecasts are of the type reviewed extensively during the 1990 Major Capital Projects hearing and updated at every GRA since that time. Changes to these forecasts and the subsequent marginal costing of utilities is clearly seen by Hydro to be beyond the scope of such a limited hearing as the present.

HYDRO EVIDENCE ON VARIABILITY OF THESE FORECASTS

The avoidance of approving variations to such fundamental planning components involved in Generation Deferral cost estimates during a limited hearing seems particularly prudent given Hydro's own comments on the variability of such forecasts. For example:

- "The generation deferral avoided cost is the most uncertain component of avoided cost and the most difficult to evaluate" (GP 90-1; page 4.1).
- "There is considerable uncertainty in the values depending on scenarios and approaches" (GP 90-1; page 4.22).
- The 1995 update (SPED Report 95-2) reviewed changes in approach for determining the generation deferral component of avoided cost in response to evidence that the sequence order and timing of future generating plans have a significant dependence on the magnitude and direction of the assumed increment of load change (SPED Report 95-2, page 3.1). A weighted average of total generation avoided cost over a wide range of scenarios was adopted; a weighted average of generation production avoided cost over the same wide range was also adopted (pages 3.2 and 3.3).

NO BASIS FOR THE CHANGE TODAY IN LIGHT OF AVAILABLE EVIDENCE

Furthermore, based on the available evidence, there is no apparent justification for Hydro's change in assigning Generation Deferral avoided costs between capacity and energy.

Earlier avoided cost reports have never attempted to justify the 50/50 assignment on any basis other than a pragmatic split which avoided the need for any more detailed determination or assessment:

a) **GP-90-1:** This initial report was prepared when the Ontario Sale and Conawapa were central to the Base Case. As reviewed at page 4.21, it was concluded that "new generation timing is initially dictated by capacity requirements and later in the sequence by energy requirements". Tables were provided in Appendix E showing capacity and energy deficits resulting from deferring each plant one year for various scenarios. These tables show energy deficits to be an important determinant of future generation plant timing.

b) **GP93-2:** This update, which was reviewed at the 1994 rate hearing (when the CSP was first approved), retained the same 50/50 approach. It provided updated capacity/energy forecast tables in Appendix B; however, these tables were not referenced as a factor affecting retention of the 50/50 approach. The overall assessment of generation deferral avoided cost (page 3.1) noted that a load reduction of 100 MW/500 GW.h per year was found to cause a one-year deferral of each generating station of the base case scenario as well as a one-year deferral of Bipole III. The generation deferral avoided cost was estimated in Table 3.1 by estimating total avoided cost due to load reduction and plant deferral, and then deducting an estimate for generation production avoided cost with load reduction and no plant delay (this method pre-assigns a large part of the plant delay saving to generation production avoided cost to reflect energy production cost savings).

c) **SPED Report 95-2:** This update, which was reviewed at the 1996/97 rate hearing, retained the same basic methods as the earlier reports (namely the two step process for estimating generation deferral avoided cost, and the 50/50 assignment of this cost between capacity and energy). The update, however, introduced changes to optimize and average results for different scenarios in recognition of significant avoided cost fluctuations under different scenarios and assumptions. Updated capacity/energy forecast tables were once again provided in Appendix B; however, these tables were not referenced as a factor affecting retention of the 50/50 approach for capacity/energy assignment of generation deferral avoided cost.

The latest Hydro evidence is that the change from 50:50 to 1/3:2/3 reflects increased confidence in the expectation that energy will continue to be the dominant factor affecting generation deferral.

At present, based on IFF97-1, we know that an energy deficit is forecast to occur about three years earlier than a capacity deficit, i.e., in 2016 versus 2019. However, similar or more significant differences in energy versus capacity deficit timing existed in both the 1993 and 1995 updates:

a) **GP 93-2:** Appendix B Base Case tables show that (without new plant) an energy deficit occurs four years earlier than a capacity deficit, i.e., in 2009 versus 2013.

b) **SPED Report 95-2:** Appendix B Base Case tables show that (without new plant) an energy deficit occurs seven years earlier than a capacity deficit, i.e., in 2011 versus 2018.

In summary, there is no evidence provided to date to establish a major shift in capacity/energy cost assignment based on energy being the dominant factor affecting generation deferral.

In dealing with a hydro-dominated system, it is recognized that energy deficits can play a major role in generation planning. Nevertheless, Hydro's own capacity/energy forecasts continue to recognize value to DSM savings for both capacity and energy. The capacity forecasts used for generation planning assign full value to all forecast DSM capacity savings (including CSP-related capacity curtailments) in assessing new capacity requirements. There has never been any suggestion in the past that generation deferral avoided cost should be assigned between capacity and energy other than on a pragmatic 50/50 basis. The earlier approach recognized the difficulties inherent in trying to justify any other specific ratio, the need to recognize deferral values for both capacity and energy, and the fact that overall generation deferral costs are reduced prior to this assignment to reflect generation production fuel cost savings.

Any change to the 50/50 approach, in short, must consider a wider range of issues and factors than those referenced to date by Hydro.

In summary, based on the available evidence, there is no apparent justification for moving from the previously approved 50:50 assignment to any new ratio, let alone the 33:66 capacity:energy ratio now proposed by Hydro.

MH/MIPUG-3

QUESTION

If the market rate for capacity were $3,000/MW-month and an Independent Power Producer (IPP) has 112 MW of capacity for sale and the rules of the market require 12% reserve on capacity, would the monthly revenue from such a sale equal $300,000?

ANSWER

It would appear that this would be the case for the assumed IPP.

In relation to the Pre-filed Testimony and the original question asked of Hydro in MIPUG/MH-9 (d), it would be more useful to consider a more relevant case. The Curtailable Service Program is not equivalent to an IPP, it is a DSM program. The curtailable customer is not required to maintain 12% reserve. Further, it is a 10% reserve that is required at the relevant Manitoba Hydro generator (MAPP rules).

Specifically, consider a case for Manitoba Hydro where there is 100 MW of potentially Curtailable Load during a summer season as measured at one of Hydro's large industrial customer's meter.

If this customer does not offer Hydro any of this curtailable load, then Manitoba Hydro would be required to maintain an appropriate reserve (assume 12% as per corporate policy) on this 100 MW of firm domestic load. Accordingly, Manitoba Hydro would not have available for short-term firm capacity export during the summer months either the 100 MW or any export that could be supported by the 12% reserve related to this 100 MW.

In contrast, if this customer offers the full 100 MW as curtailable load, Manitoba Hydro would no longer need to maintain the 12% reserve on this load related to its domestic firm requirements. Ignoring the extent to which transmission loss savings might affect the assessment, assume that 112 MW is now available at Hydro' generator to support short-term firm monthly summer export of capacity. MIPUG/MH-9 states that "Manitoba Hydro must maintain a reserve of 10% to meet the RCO requirement of MAPP". Therefore under this example, revenue from 101.8 MW (112/1.1) of capacity available for export would result. Suggesting that the customer's curtailable load must be reduced by 12% in order to make MAPP sales (down to 89.3 MW) would be inaccurate and would result in 22.7 MW (112-89.3) of reserve (25%) being retained where only 10% was required.

PUB/MIPUG-1

QUESTION:

Please provide a narrative description explaining Table 1, including sources of data, and summarize the important conclusions drawn from this Table.

ANSWER

Table 1 in the pre-filed testimony summarizes a number of alternative means for calculating the reference discount related to Generation Deferral (winter). It highlights changes in values and assumptions since Hydro's 1993 analysis. It also shows impacts on a year-to-year basis over the five-year period for the new CSP. This table has now been updated in MH/MIPUG-1(b) to include the MIPUG suggested method for calculating the reference discount and to allow for easier reading. The summary of this table is as follows:

IMPACT OF CHANGES IN CAPACITY/ENERGY ASSIGNMENT OF GENERATION DEFERRAL AVOIDED COST

On the upper half, the marginal cost calculation leading to the Generation Deferral value is summarized. This is done for four different approaches. Column 1 is the data from the 1993 analysis related to the initial experimental curtailable service program; column 2 is the application of the 1993 methodology to the 1998 figures (as provided in the current application); column 3 is the approach proposed by MIPUG; column 4 is the approach outlined in the current Hydro application.

The basic value for deferral ($/MW.h) for Column 1 (1993) comes from GP 93-2, as filed in the 1994/95 GRA (see Table 3.1 in that report, where Generation Deferral avoided cost of $5.30/MW.h in 1993$ is derived, based on Hydro's methodology for assessing this avoided cost component). Based on the 50:50 capacity and energy assignment of this cost that was then adopted, the Generation Deferral capacity cost in 1993$ equals $13.20/kW/yr (see Table 3.2 of GP 93-2; this same value is also provided in Table 1 of Attachment Exp Curt-1 in the present 1998 Hydro filing). The calculation of $13.20 reflects the following:

a) 50% of the $5.30/MW.h assigned to capacity.

b) Assumption of 8,766 hours/year and an average capacity factor of approximately 57%.

The basic value of deferral ($/MW.h) for Columns 2-4 is derived from Manitoba Hydro's 1996$ capacity value assessment of $8.47/kW/year based on a 33:67 capacity to energy assignment and an assumed average capacity factor of 59% (as per the 1995 update SPED 95-2 as filed in the 1996/97 GRA). The values assigned to capacity ($/kW/yr) in Table 1, Columns 2-4, can be found in MIPUG/MH-8(a)(i) for column 4, MIPUG/MH-8(a)(ii) for column 2, while column 3 is simply an arithmetic average of these two values. This analysis reflects changes in Hydro's assumptions in 1993 versus the latest update as regards the capacity:energy assignment for Generation Deferral avoided cost.

OTHER METHOD CHANGES SINCE 1993

The other adjustments are as follows: removal of 4% for distribution loss (columns 3 and 4) removal of 12% for capacity reserve (column 4) and an equivalence to generator factor of 80% (columns 1-4). The resulting figures are the Reference discounts in the relevant dollar value (1993$ for column 1, 1996$ for columns 2-4). This analysis highlights that the other method changes introduced the 4% and 12% discounts since 1993. MIPUG's proposed approach includes the 4% discount but does not include the 12% discount.

OPTION 1 AND OPTION 2

The value for the five year program for Option 1 is simply adjusted by two years inflation (at 2%) to get 1998$, while Option 2 is adjusted through the five-year levelization approach used by Manitoba Hydro in Attachment Exp Curt-1, page 28. Only Option 1 is relevant so long as there is to be an adjustment for inflation each year (starting in the second year) throughout the program. The five-year levelized approach (Option 2) was not used in 1993.

The bottom half of the table is an outline of the relevant reference discounts through the years of the program for both Option 1 (adjusted each year for inflation) and Option 2 (no adjustment for inflation). The final column outlines the value for A in the A+Bx equation proposed by Hydro for each calculation method. MIPUG is suggesting that the $0.70 figure is more consistent with the eligible changes in such a limited hearing, and recognition of the fact that the CSP is a DSM program. Hydro's proposed $0.50 figure is also indicated (see CSP-1, Note 1).

PUB/MIPUG-2

QUESTION

Please provide a narrative description explaining Table 2, including sources of data, and summarize the important conclusions drawn from this Table.

ANSWER

Table 2 in the pre-filed testimony summarizes a number of alternative means for calculating the reference discount related to Generation Production (summer). It highlights changes in the 12% reserve assumptions since Hydro's 1993 analysis. It also shows the impacts on a year-to-year basis over the five-year period for the new CSP. This table has now been updated in MH/MIPUG-1(b) to include the MIPUG suggested method for calculating the reference discount and to allow for easier reading. The summary of this table is as follows:

12% RESERVE ASSUMPTIONS

On the upper half, the marginal cost calculation leading to the Generation Production value is summarized. This is done for two different approaches. First is the 1993 Hydro method without the reduction of 12% for reserve, while the second column is the approach currently used by Manitoba Hydro (with 12% for reserve). All values are sourced to Exp Curt Attachment-1.

A US$ exchange rate is absent from this part of the table, as the reference discount is now subject to monthly modifications for US$ exchange rate (and is thus calculated in US$) along with annual inflation rates. Option 1 reflects this approach. Option 2 retains the conversion to C$ and the levelized inflation rate, as per Exp Curt-1, page 28.

Each column is subject to the adjustment for equivalent generator at 80%, but only the second column is subject to the 12% generation reserve adjustment.

OPTION 1 AND OPTION 2

The Value for 1998-2003 Five-Year Program for Option 1 is simply the figures derived in the upper part of the table adjusted for one year of inflation (1997$ to 1998$). Option 2 involves the adjustment for forecast US$ exchange rate and levelized inflation adjustment. Only Option 1 is relevant so long as there is to be adjustment for inflation and the exchange rate throughout the program.

The bottom half of the table is an outline of the relevant reference discounts through the years of the program for both Option 1 (adjusted each year for inflation and US$ exchange rate) and Option 2 (no ongoing adjustment for inflation or US$ exchange rate). The final column outlines the value for B in the A+Bx equation proposed by Hydro for each calculation method. MIPUG is suggesting the $0.94 figure for 1998-1999 and the $1.12 figure for subsequent years. Hydro's proposal is $0.84 for 1998-1999 and $1.00 for subsequent years.

The values for Option 1 related to "subsequent" years (after 1998/99) reflect the \$2,750 US\$/month basic value projected by Hydro (1997\$) for short-term firm exports over the six months (see Exp Curt Attachment 1). The value for Option 1 related to 1998/99 reflects a reduction of 450 US\$/month, related to delay in the new transmission value (see Exp Curt-25).

PUB/MIPUG-3

QUESTION - reference page 6

Under what circumstances would you conclude that the 12% reduction for summer capacity is reasonable, and what additional information would you require to arrive at that conclusion?

ANSWER:

The circumstances and information required to conclude that the 12% reduction for summer capacity is reasonable would be factual information addressing the direct impact of CSP summer curtailable load on Hydro's revenues realized from summer capacity sales which indicates that Hydro realizes only 90.9% of the sale price for each MW of curtailable load made available by a customer during summer months. Any such calculation should implicitly compare Hydro's revenues from export sales without and with the curtailable load, assuming that all summer CSP sales (as with any other DSM program) are transferred from existing firm load.

Questions MIPUG/MP-9(d) sought to obtain this type of information. Hydro's response dealt only with "100 MW of capacity", which ignores the issue as to whether 100 MW of customer load being curtailed in summer results in Hydro having available new capacity for export purposes of 100 MW of sales load plus 12% reserve on that previous sales load. If Hydro must maintain reserve in its own firm domestic sales, then it is reasonable to assume that curtailable load (which would otherwise be firm load) releases both the customer's own purchase requirement and Hydro's reserve related to that customer load.

In summary, the 12% reduction for reserve relating to summer capacity is unreasonable under the circumstances outline in MIPUG's response to MH/MIPUG-3.

Aside from the above issues related to assessment of curtailable versus firm loads, there may also be issues related to how the MAPP agreement is applied under these circumstances.

For example, MAPP rules regarding Reserve Capacity Deficiency Service (sales of capacity) state that rates will be based on "each megawatt or fraction thereof *committed* by the supplier..."(emphasis added). It is not quickly apparent that reserves are excluded from the reference commitment upon which the rate is paid.

It also remains unclear what added revenue benefits Hydro will secure from the change to certify the CSP as a Certified Interruptible Demand. This type of benefit to Manitoba Hydro may increase the calculation of the value of summer capacity even if it is not directly related to the 12% reserve issue.

PUB/MIPUG-4(a)

QUESTION - Reference page 6

(a) What is the magnitude of the dollar value impact of changing the capacity/energy ratio from 50/50 to 33.3/66.6 and why is it suggested that the "impacts of the specific change" might be moderated for the CSP over the next five years?

ANSWER

Table 1 in MH/MIPUG-1(b) indicates that the value of this change suggested by Manitoba Hydro is $4.20 per kW/yr assigned to capacity ($12.67-$8.47), prior to any other adjustments. The magnitude of impacts for the curtailable customer vary slightly depending on the 12% reserve issue. Focusing on Hydro's proposed approach (Column 4 in Table 1), substituting $12.67 for $8.47 would increase the value of "A" in the A+Bx equation from $0.50 to $0.75. This indicates a customer dollar value impact of $0.25/kW/month (in 1998$) of changing the capacity/energy ratio from 50/50 to 33.3/66.6 (a reduction of 33%).

The rationale for changing the 50:50 capacity:energy ratio to 1/3:2/3 is based on updated system planning forecasts. For the reasons outlined in MH/MIPUG-2, it is inappropriate to revise such fundamental forecasts (or the values that derive from them) at a limited hearing regarding industrial rate programs.

Focusing only on the CSP extension, the Hydro proposal will fix the Reference Discount for the next five years (subject to inflation and exchange rate adjustments). This Reference Discount would not be subject to review at any general rate hearing held during this period when parties might have the opportunity to assess Hydro's latest forecasts, capital plans and marginal cost estimates. These circumstances underline MIPUG's concern about accepting, for the purpose of the Reference Discount over the next five years, such a major and untested change in Hydro's marginal cost assessment related to a shift in an assumption as to the allocation of generation deferral costs assigned to capacity versus energy.

The proposal for moderating the impacts of this change over the next five years reflects rate stability objectives and an assumption that this hearing will not review in detail the Hydro cost method changes.

For the purpose of rate setting (which is what is happening with the CSP), one of the recognized rate design principles is "rate stability". Based on this principle, MIPUG has consistently emphasized the relevance of smoothing out rate adjustments over longer-term periods when dealing with capital intensive aspects of the system such as the generation deferral cost component. The original avoided cost report (GP 90-1), which proposed the 50/50 assignment method, also highlighted the need for long-term stable avoided cost values (see page 4.25 of GP 90-1 which recommended against varying the deferral avoided cost over the 1995 to 2028 time frame).

In summary, the rate stability objective indicates the relevance of moderating the impacts of this change when setting CSP rates for the next five years.

PUB/MIPUG-4(b):

QUESTION - Reference page 6.

(b) Please explain the basis for averaging the 1993 and 1998 approached for calculating the winter capacity value (as opposed to choosing one or the other)?

ANSWER

The basis for averaging the 1993 and 1998 approaches, rather than choosing one or the other, reflects a pragmatic assessment of the scope for this hearing, the issues potentially involved in choosing one or the other (or some third option not yet identified), and the commitment to pursue rate stability objectives.

The generation planning process is dynamic and changes arise relatively quickly based on a number of corporate forecasts. We have seen such changes since 1990, for example, when capacity was expected to be the dominant factor affecting generation deferral in the initial years (GP 90-1 page 4.21). The approach proposed by Manitoba Hydro (1998 approach) implies a major revision to the generation planning forecasts and marginal cost studies last tested before the PUB. Our concerns about dealing with this change during this hearing are set out elsewhere (see MH/MIPUG-2 and PUB/MIPUG-4(a).

In response to these concerns, it is suggested that the proposal by Manitoba Hydro be moderated. The average of the 1993 approach and the 1998 approach results in a $0.12 reduction in the Generation Deferral portion of the curtailable credit from the 50:50 approach.

In principle, it would be preferable to proceed on the following basis:

a) **review forecasts and avoided cost changes:** This would require full assessment of the updated avoided cost analysis and a determination as to its acceptability and applicability for the purpose of the CSP rates.

b) **consider changes to Reference Discount for CSP rates in light of rate stability and other rate design principles:** For the purpose of the CSP five-year Reference Discount, it is appropriate to consider how best to address rate stability objectives. It is certainly not acceptable to have five-year Reference Discount rates subject to major fluctuation based on Hydro's most recent forecasts and avoided cost method changes related to generation deferral costs (a cost factor which in essence relates to the long term).

Even if the Board could complete step (a) above in the hearing (which seems unlikely, given the scope of the hearing and the evidence filed to date), it would still be reasonable to assess item (b) and the possible application of some moderating approach to smooth out any major change in methods and to reduce the risk of further future instability on this point.

An alternative to the proposal for averaging would be to retain the 50/50 approach until such time as Hydro provides tested evidence sufficient to satisfy the Board that a change in methods is reasonable.

PUB/MIPUG-4(c)

QUESTION

(c) Have you considered other ways to moderate the impact other than a simple average?

ANSWER

The only other way considered to moderate the impact of the change from 50/50 to 33/66 was based on a phase-in of the revision over the course of the program. This was rejected because it presumed acceptance of the new ratio as a valid approach that would be retained (or further shifted in the same direction) after the next five years. As noted, we have no basis at present to accept this new ratio or to believe it will be appropriate after the next five years (see MH/MIPUG-2). At present, it remains possible that over the five years of the program, the appropriate ratio between capacity:energy could be updated a number of times, and thus the target (1/3:2/3 by the year 2002-2003) may be completely out of line with future system planning forecasts.

Hydro already uses extensive averaging to calculate the basic values for generation deferral avoided costs (see SPED Report 95-2). The issue in this instance is the relative reasonableness of the 50:50 and 33:66 numbers adopted for an average.

Based on the available evidence (see MH/MIPUG-2), the 50:50 approach already reflected considerable pragmatism and averaging of possible scenarios. In contrast, no rationale has been proposed for selecting 33:66 (rather than 45:55, 40:60 or some other shift in the 50:50 approach). Accordingly, the whole issue of "moderating the impact" might be deferred by retaining the 50:50 approach for the purpose of CSP rates until such time as all of the issues can be reviewed properly at a full general rate hearing.

PUB/MIPUG-5

QUESTION

Please indicate whether MIPUG (or any of its members) was a part of the Curtailable Rates Monitoring Committee and, if so, whether MIPUG was aware of, and voiced concern with, the three changes disputed by MIPUG in its evidence that Manitoba Hydro has applied for.

ANSWER

MIPUG has been actively involved in the Curtailable Rates Monitoring Committee since its outset and was a participant in the design on the proposed permanent program since late 1995. As a result of this participation, agreement on a number of issues was secured between Manitoba Hydro and MIPUG.

Starting in the fall of 1997, and carrying through to late April of 1998, MIPUG reviewed drafts of Hydro's report on the CSP and Hydro's proposals for this program after March 1998. MIPUG voiced concern about apparent changes in the underlying assumptions in calculation of the Reference Discount relative to the 1993 analysis, and specifically the changes in the capacity/energy assignment of Generation Deferral capacity avoided costs (from 50:50 to 33:66) and the adjustment to reduce capacity costs for a 12% reserve in summer and winter. During 1997 and early 1998, these and other changes were identified and discussed at different metings and MIPUG's concerns were clarified.

In January 1998, in response to concerns about further delay in filing Hydro's application to extend the program after March 1998, MIPUG suggested that the matters which could not be resolved could be addressed by the PUB when it reviewed the application. Subsequently, Hydro and MIPUG agreed that these outstanding issues with respect to the value of curtailable load, and therefore the quantum of the Reference Discount, will have to be resolved before the PUB.

In late April 1998, MIPUG suggested that Hydro consider some form of "splitting-the-difference", as per an average related to the three specific outstanding issues related solely to the change in approach adopted in 1998 versus 1993. Hydro was not able to accept this suggestion, and it was again noted that this matter will have to be resolved before the PUB.

PUB/MIPUG-6

QUESTION

Please provide copies of the relevant sections of the 1990, 1993 and 1995 reports that MIPUG is relying upon in its evidence.

ANSWER

The relevant portions of the documents referred to in the pre-filed testimony are attached.

For further reference, the documents were all submitted to previous PUB hearings and can be found in the locations noted:

The document GP 90-1 is from the 1990 Major Capital Projects of Manitoba Hydro hearing in CAC/MSOS(I) 15.2 Attachments

The document GP 93-2 is from the 1994/95 GRA in response to MIPUG/MH(I)-4(a)

The document SPED 95-2 is from the 1996/97 GRA in response to MIPUG/MH(I)-11(a)