PUBLIC UTILITIES BOARD INFORMATION REQUESTS OF RCM/TREE'S WITNESS, ROGER COLTON.

PUB/RCM/TREE-1. Reference: Exhibit RDC-1 CV p.15-22

For the regulatory bodies that you have testified before and recommended rate affordability programs, please identify which bodies have not implemented your recommendations to implement such programs.

Response:

Mr. Colton has testified before dozens of regulatory bodies over the course of 25 years. In many cases, he has testified before the same regulatory body more than once. These bodies have adopted (or not adopted) his recommendations in shades of grey, both in the timing of the adoption and in the extent of the adoption. Mr. Colton has not tracked which states have or have not adopted his recommendations over time.

In Canada, both the Ontario Energy Board (OEB) and the Nova Scotia Utility and Review Board have declined to adopt low-income affordability programs.

PUB/RCM/TREE-2. Reference: Exhibit RDC-2 p.2

a) Mr. Colton proposes that an affordable home energy burden is 6% of income. Please explain why you have selected this threshold instead of the threshold identified by RCM/TREE in the 2007/08 & 2008/09 Centra Gas GRA: "The evidence before the Board suggests that energy poverty arises when the energy costs account for more than 9 or 10 percent of household income." [transcript p.1523-1524]

b) Please provide excerpts from the reports listed in the bibliography not authored by Mr. Colton that support the 6% threshold for affordable home energy burdens. If there are reports supporting a different threshold for affordable home energy burden, please file excerpts of these as well.

Response:

(a) The reference to "energy poverty" in the quotation cited above would seem to indicate that the speaker was looking to the experience of Great Britain in his or her comments. Based on the cited transcript pages, Mr. Colton does not know who the quoted speaker was. Moreover, the speaker draws his or her conclusion based upon an explicit reference to "the evidence before the Board"; Mr. Colton does not know what "evidence before the Board" was being considered or how that evidence was "suggesting" that energy poverty arises when energy costs account for more than 9 or 10 percent of household income.

Having said that, Mr. Colton notes that Great Britain refers to the unaffordability of home energy as "energy poverty" (sometimes also referred to as "fuel poverty"). Great Britain also uses a 10% standard by which to define the limits of "energy poverty."

The Great Britain 10% standard and the 6% standard recommended by Mr. Colton, however, are not comparable with each other. To the extent that the question assumes that the standards are in conflict, the question errs. In defining "energy poverty," Great Britain uses a very narrow definition of "income," unlike Mr. Colton's use of gross household income. For example, in defining "energy poverty" as 10% of income, Great Britain excludes mortgage and rental costs from income before applying the 10%. Moreover, the 10% standard used in Great Britain does not look at actual home energy expenditures. Rather, the 10% standard is based on the energy needed to provide "adequate" home energy service to a household. Given these differences, it is not possible to directly compare the 6% standard recommended by Mr. Colton with a 10% standard based on Great Britain's "energy poverty" (or "fuel poverty") considerations.

Mr. Colton is not aware of the extent to which the speaker was asked about, and given the opportunity to explain, the way in which Great Britain defines and applies the term "energy poverty" based on the 10% standard. The fact that the question is a transcript citation would appear to indicate that no such explanation was requested or provided.

Mr. Colton can provide additional information on the Great Britain use of the term "energy poverty" (or "fuel poverty") upon request.

(b) To review each report cited in Mr. Colton's bibliography for purposes of excerpting those sections which "support" a specific number would require a special study that Mr. Colton declines to undertake as being beyond the purview of appropriate discovery. However, the attached CDROM provides copies of each report cited by RCM/TREE in its discovery request to Manitoba Hydro (RCM/TREE-171), which include some reports authored by Mr. Colton and other reports not. It is not possible to provide "excerpts" of those reports because the "support" offered by such reports is cumulative, is synergistic, and is spread throughout the reports, with the support offered by the report as a whole being different from, and more compelling than any individual section of the report standing alone.

Mr. Colton notes that the two most recent percentage of income programs adopted in the United Stations (Xcel Energy: Colorado; Illinois) both use the 6% standard.

PUB/RCM/TREE-3. Reference: Exhibit RDC-2 Table 5 p.20

Please confirm that while only 35 payment arrangements were made per 100 accounts in arrears greater than 90 days, some of the remaining 65 accounts may have been made current by paying in full.

Response:

Confirmed. Some accounts in arrears may be made current by paying in full. However, by definition, to the extent that the account is listed as having arrears greater than 90 days, that account has not been "paid in full" as posited by the question.

PUB/RCM/TREE-4. Reference: Exhibit RDC-2 p.32

a) Please confirm whether a 25% reduction in consumption for low income customers with bills in excess of $3,000.00 would result in bills 60% to 140% (electric heat) and 60% to 90% (gas heat) **higher** than the company residential average. (Note: it appears that the figures stated on p.32 are the percentages **of** the company's residential average, not percentages **higher** than the average)

b) In your view, please explain the reasons why 37,500 low income customers have energy bills that exceed the residential average. Please explain why MH-funded initiatives that seek to reduce the energy bills do not address the bill affordability problem for these customers.

c) Do you agree that lower income homes with above average electricity or gas consumption present more opportunities for efficiency savings than homes that have below average consumption? If so, please give your views on whether reductions in consumption greater than 25% are feasible for these high consumption homes. If not, please explain why these homes have consumption greater than the residential average.

Response:

a. Confirmed. The percentages presented on page 32 are the bills after being reduced for energy efficiency savings as a percentage of the original bill. Thus, for example, the reduced bills for electric heating are 160% to 240% of the non-reduced bills, meaning that the bills are 60% to 140% higher than the pre-treatment bills.

b. Insufficient data is available to Mr. Colton to accurately and comprehensively respond to the question of why 37,500 low-income customers have bills that exceed the residential average. Mr. Colton's conclusion is not merely that MH-funded energy efficiency initiatives _do_ not address the bill affordability problems for these customers, but that MH-funded energy efficiency initiatives _can_ not address the bill affordability problems for these customers. The basis for this conclusion is set forth in Mr. Colton's report, at pages 31 through 37, and includes, without limitation, the following observations:

- The offer of energy efficiency assistance cannot help a customer make a payment by a date certain in response to a notice of an impending disconnection of service for nonpayment.
- Given reasonably anticipated budget limitations, the number of customers with higher-than-average bills could not be treated in a reasonable time frame.

- Given reasonably anticipated usage reduction levels, bills would remain above an affordable percentage of income.
- The bill reductions needed to achieve affordability are beyond those that are reasonably to be expected from LIEEP.
- Market barriers unique to the poor prevent low-income participation in usage reduction programs.

c. Mr. Colton believes that high usage customers present greater potential for energy saving than do low usage customers, all other things equal. Mr. Colton references the report on the Pennsylvania Low-Income Usage Reduction Program (LIURP) as documenting the reasonably expected usage reduction outcomes generated by an energy efficiency program that is coupled with a rate affordability program. Mr. Colton finally notes that he does not assert that a 25% bill reduction is routinely achievable, but rather his report sets forth the 25% bill reduction as an "even if" analysis (i.e., even if a 25% reduction were achieved, bills would remain unaffordable). Usage reduction sufficient to reduce bills to an affordable level is not likely for these houses.

PUB/RCM/TREE-5. Reference: Exhibit RDC-2 Table 10 p.34

Please re-file several versions of Table 10 on page 34 using incomes of $27,000.00, $42,000.00, and $58,000.00.

Response:

The requested "versions" are set forth as three scenarios: (1) Scenario 1 involves an income of $27,000; (2) Scenario 2 involves an income of $42,000; and (3) Scenario 3 involves an income of $58,000. These three Scenarios are appended to this response as PUB/RCM/TREE-5, Attachment 1.

PUB-RCM-TREE-5, Attachment 1: Scenario 1

<$250	219	$1,620	$222	0%	4,515	$1,620	$230	0%
$251 - $500	2,137	$1,620	$414	0%	8,084	$1,620	$328	0%
$501-$750	2,960	$1,620	$606	0%	2,707	$1,620	$599	0%
$751 - $1,000	2,623	$1,620	$868	0%	1,814	$1,620	$903	0%
$1,001 - $1,250	3,955	$1,620	$1,127	0%	3,117	$1,620	$1,156	0%
$1,251 - $1,500	4,770	$1,620	$1,375	0%	7,152	$1,620	$1,374	0%
$1,501 - $1,750	4,446	$1,620	$1,625	0%	11,696	$1,620	$1,627	0%
$1,751 - $2,000	3,315	$1,620	$1,849	12%	10,370	$1,620	$1,872	13%
$2,001 - $2,250	2,244	$1,620	$2,129	24%	5,937	$1,620	$2,105	23%
$2,251 - $2,500	1,121	$1,620	$2,399	32%	3,794	$1,620	$2,351	31%
$2,501 - $2,750	622	$1,620	$2,624	38%	2,061	$1,620	$2,613	38%
$2,751 - $3,000	583	$1,620	$2,819	43%	705	$1,620	$2,840	43%
$3,001 - $3,250	554	$1,620	$3,111	48%	460	$1,620	$3,118	48%
$3,251 - $3,500	187	$1,620	$3,415	53%	362	$1,620	$3,381	52%
$3,501 or more	375	$1,620	$4,668	65%	311	$1,620	$3,786	57%

PUB-RCM-TREE-5, Attachment 1: Scenario 2

<$250	219	$2,520	$222	0%	4,515	$2,520	$230	0%
$251 - $500	2,137	$2,520	$414	0%	8,084	$2,520	$328	0%
$501-$750	2,960	$2,520	$606	0%	2,707	$2,520	$599	0%
$751 - $1,000	2,623	$2,520	$868	0%	1,814	$2,520	$903	0%
$1,001 - $1,250	3,955	$2,520	$1,127	0%	3,117	$2,520	$1,156	0%
$1,251 - $1,500	4,770	$2,520	$1,375	0%	7,152	$2,520	$1,374	0%
$1,501 - $1,750	4,446	$2,520	$1,625	0%	11,696	$2,520	$1,627	0%
$1,751 - $2,000	3,315	$2,520	$1,849	0%	10,370	$2,520	$1,872	0%
$2,001 - $2,250	2,244	$2,520	$2,129	0%	5,937	$2,520	$2,105	0%
$2,251 - $2,500	1,121	$2,520	$2,399	0%	3,794	$2,520	$2,351	0%
$2,501 - $2,750	622	$2,520	$2,624	4%	2,061	$2,520	$2,613	4%
$2,751 - $3,000	583	$2,520	$2,819	11%	705	$2,520	$2,840	11%
$3,001 - $3,250	554	$2,520	$3,111	19%	460	$2,520	$3,118	19%
$3,251 - $3,500	187	$2,520	$3,415	26%	362	$2,520	$3,381	25%
$3,501 or more	375	$2,520	$4,668	46%	311	$2,520	$3,786	33%

PUB-RCM-TREE-5, Attachment 1: Scenario 3

<$250	219	$3,480	$222	0%	4,515	$3,480	$230	0%
$251 - $500	2,137	$3,480	$414	0%	8,084	$3,480	$328	0%
$501-$750	2,960	$3,480	$606	0%	2,707	$3,480	$599	0%
$751 - $1,000	2,623	$3,480	$868	0%	1,814	$3,480	$903	0%
$1,001 - $1,250	3,955	$3,480	$1,127	0%	3,117	$3,480	$1,156	0%
$1,251 - $1,500	4,770	$3,480	$1,375	0%	7,152	$3,480	$1,374	0%
$1,501 - $1,750	4,446	$3,480	$1,625	0%	11,696	$3,480	$1,627	0%
$1,751 - $2,000	3,315	$3,480	$1,849	0%	10,370	$3,480	$1,872	0%
$2,001 - $2,250	2,244	$3,480	$2,129	0%	5,937	$3,480	$2,105	0%
$2,251 - $2,500	1,121	$3,480	$2,399	0%	3,794	$3,480	$2,351	0%
$2,501 - $2,750	622	$3,480	$2,624	0%	2,061	$3,480	$2,613	0%
$2,751 - $3,000	583	$3,480	$2,819	0%	705	$3,480	$2,840	0%
$3,001 - $3,250	554	$3,480	$3,111	0%	460	$3,480	$3,118	0%
$3,251 - $3,500	187	$3,480	$3,415	0%	362	$3,480	$3,381	0%
$3,501 or more	375	$3,480	$4,668	25%	311	$3,480	$3,786	8%

PUB/RCM/TREE-6. Reference: Exhibit RDC-2 p.45

Please provide references supporting the "generally accepted" position that a household's shelter burden should not exceed 30% of income, and that the utility bill should not exceed 20% of the shelter burden. Please include references not authored by Mr. Colton, if possible.

Response:

(a) Mr. Colton has not undertaken a study to develop a bibliography to support the assertion that a household's shelter burden should not exceed 30% of income. However, merely to illustrate, Attachment PUB/RCM/TREE-6a is a brief White Paper by Mary Schwartz and Ellen Wilson of the U.S. Census Bureau. The White Paper, titled "Who Can Afford to Live in a Home: A Look at Data from the 2006 American Community Survey," states in relevant part:

> "The conventional public policy indicator of housing affordability in the United States is the percent of income spent on housing. Housing expenditures that exceed 30 percent of household income have historically been viewed as an indicator of a housing affordability problem. The conventional 30 percent of household income that a household can devote to housing costs before the household is said to be "burdened" evolved from the United States National Housing Act of 1937.
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> * * *
>
> "Because the 30 percent rule was deemed a rule of thumb for the amount of income that a family could spend and still have enough left over for other nondiscretionary spending, it made its way to owner-occupied housing too. Prior to the mid 1990s the federal housing enterprises (Fannie Mae and Freddie Mac) would not purchase mortgages unless the principal, interest, tax, and insurance payment (PITI) did not exceed 28 percent of the borrower's income for a conventional loan and 29 percent for an FHA insured loan. Because lenders were unwilling to hold mortgages in their portfolios, this simple lender ratio of PITI to income was one of many "hurdles" a prospective borrower needed to overcome to qualify for a mortgage. There are other qualifying ratios as well; most of which hover around 30 percent of income. The amount of debt outstanding and the size and frequency of payments on consumer installment loans and credit cards influence the lender's subjective estimation of prospective homebuyers' ability to meet the ongoing expenses of homeownership. Through the mid 1990s, under Fannie Mae guidelines for a conventional loan, total allowable consumer debt could not exceed eight percent of borrower's income for conventional mortgage loans and 12 percent for FHA-insured mortgages. So through the mid 1990s, underwriting standards reflected the lender's perception of loan risk. That is, a household could afford to spend nearly 30 percent of income for servicing housing debt and another 12 percent to service consumer debt. Above these thresholds, a household could

> not afford the home and the lender could afford the risk. While there are many underwriting standards, none of them made their ways into the public policy lexicon like the 30 percent of income indicator of housing affordability.
> "The mid to late 1990s ushered in many less stringent guidelines. Many households whose housing costs exceed 30 percent of their incomes are choosing then to devote larger shares of their incomes to larger, more amenity-laden homes. These households often still have enough income left over to meet their non-housing expenses. For them, the 30 percent ratio is not an indicator of a true housing affordability problem but rather a lifestyle choice. But for those households at the bottom rungs of the income ladder, the use of housing costs in excess of 30 percent of their limited incomes as an indicator of a housing affordability problem is as relevant today as it was four decades ago."

The notes have been omitted from this excerpt, but the entire paper is appended.

Moreover, the National Low-Income Housing Coalition (NLIHC) publishes an annual survey of housing costs in the United States. NLIHC states:

> Despite the emphasis on homeownership and the marginalization of renters, renter households still make up fully one-third of the households in the United States — almost 38 million households. *Out of Reach* is a side-by-side comparison of wages and rents in every county, Metropolitan Area (MSAs/HMFAs), combined nonmetropolitan area and state in the United States. For each jurisdiction, the report calculates the amount of money a household must earn in order to afford a rental unit in a range of sizes (0, 1, 2, 3, and 4 bedrooms) at the area's Fair Market Rent (FMR), based on the generally accepted affordability standard of paying no more than 30% of income for housing costs.

The results of the NLIHC study are not as important, for purposes of this response, as is its recognition of "the generally accepted affordability standard of paying no more than 30% of income for housing costs."

Mr. Colton notes, finally, that Professor Carter, in his report in this proceeding, makes the following statement: "In Canada, households are considered to have a housing affordability problem if they pay 30% or more of gross, before tax household income on shelter." (Carter, at 23).

(b) Mr. Colton has not undertaken a study to develop a bibliography to support the assertion that a household's utility costs should not exceed 20% of total shelter costs. However, merely to illustrate, the U.S. Department of Labor's Consumer Expenditures Survey documents the following utility costs as a percentage of shelter costs for 2009 by income quintile. As can be expected, the utility costs are somewhat higher than 20% for the lowest income quintiles, somewhat lower than 20% for the highest income quintiles, and almost exactly 20% for the middle income quintile.

All consumer units	Lowest 20 percent	Second 20 percent	Third 20 percent	Fourth 20 percent	Highest 20 percent
17%	23%	23%	19%	16%	12%

Mr. Colton's conclusion is further bolstered by his own jurisdiction-specific review of home energy bills as a percentage of Fair Market Rents (FMRs) annually published by the U.S. Department of Housing and Urban Development (HUD). With some natural variation around the 20% norm, the home energy bills tend to represent 20% of FMRs across the 3500+ jurisdictions.

PUB/RCM/TREE-7. Reference: Exhibit RDC-2 p.45

a) Please explain whether it is possible with a fixed credit program for the fixed credit to exceed the current bill, and thus the utility owes the customer. Please elaborate on the utility's options and possible outcomes for this situation.

b) Please detail the calculations that result in an estimated fixed credit program cost of $10.8 million. Please clearly state any assumptions.

c) If customer incomes must be forecasted to calculate the fixed credit total program cost, please comment on any difficulties MH may experience attempting to forecast customer incomes for two future test years.

Response:

(a) It is not possible for a fixed credit to exceed the current bill. The fixed credit is that dollar amount needed to reduce a customer's bill to an affordable percentage of income. If a bill is sufficiently small so that it is less than the affordable percentage of income, the fixed credit would be $0. The fixed credit would never be bigger than the actual bill. Indeed, given extremely low-incomes, it is a common practice for a percentage of income program to impose a minimum payment requirement for program participants.

(b) The calculation of the $10.8 million is appended to this response as Attachment PUB-RCM-TREE-7b.

(c) Customer incomes need not be forecasted to calculate the fixed credit. Common mechanisms used to establish income include using annual or annualized income (30-, 60-, 90-, 180-days). Customer income is generally re-verified annually, with less frequent re-verification for customers with income sources that are not likely to substantially change from year-to-year.

PUB/RCM/TREE-8. Reference: Exhibit RDC-2 p.47-49

a) The statement: "According to Manitoba Hydro, 'there is no direct correlation between energy consumption and income,'" is in conflict with the findings from the 2009 Residential Energy Use Survey Report – Low Income Cut-off Sector (by MH, May 2010). On page iv of this report, MH states "LICO customers consume less electricity than non-LICO customers." Please comment on the implications to the tiered discount program of a correlation between income and consumption.

b) In Table 15 on p.49, it appears that Mr. Colton is advocating waiving of the customer charge for those customers that do not require a discount to make their bills affordable. Please confirm whether the customer charge is MH's Basic Monthly Charge, and whether this is in fact the suggested course of action. If Mr. Colton is advocating waiving of the BMC, please explain why.

c) It is not clear from Mr. Colton's program description why the tiered discount program is at the risk of weather and commodity price. Please provide further explanation. Is the tiered discount program not like the fixed credit program where the credit and the required funding are established at the start of the year?

Response:

(a) To the extent that income is correlated with electricity consumption, and by extension, with electricity bills, the cost of a tiered discount program would be less. This occurs because the dollar bill reduction needed to achieve an affordable bill would be lower. Unlike a percentage of income program, where both the number of participants and the cost per participant (and thus the aggregate cost) would decrease, a lower electricity consumption associated with lower incomes would lower the program cost but not the program participation rate for a tiered discount program.

(b) Mr. Colton confirms that the customer charge is Manitoba Hydro's Basic Monthly Charge. Just as Mr. Colton believes a minimum payment is reasonable, he believes that a minimum discount is reasonable given a tiered discount program. This is true because a tiered discount program achieves affordability only for customers that are exactly at the average income and average energy use. Customers with lower income or higher energy use do not fall into the affordable range. A minimum discount equal to the Basic Monthly Charge (i.e., the "customer charge") would help avoid the likelihood that customers with unaffordable bills would receive a corresponding discount.

It should be noted, however, that Mr. Colton did not "advocate" for a Basic Monthly Charge waiver. Instead, Mr. Colton recommended use of a percentage of income model. Under the percentage of income model, if a customer's bill is less than the affordable percentage of income, the customer would receive no benefit (with the exception of limited arrears credits if the program participant maintains his or her budget billing plan).

(c) The tiered discount program is not a fixed credit program. The tiered discount program provides a discount off the bill at standard rates. If the annual bill is $1,200 and the discount is 60%, the discount is $720 ($1,200 x 0.60 = $720). If due to weather or other factors the bill at standard rates increases to $1,400, the discount increases to $840 ($1,400 x 0.60 = $840). The trade-off is that the customer accepts the risk that his or her bill and/or income will not be at the average, but shares the risk that the bill will change due to weather or for other reasons.

PUB/RCM/TREE-9. Reference: Exhibit RDC-2 p.53, 55

a) Please comment on whether an arrears management program such as the one suggested by Mr. Colton that incorporates an element of arrears forgiveness encourage customers to incur arrears, knowing that a percentage will eventually be forgiven.

b) Please provide support for the assumption that only 12% (30% of 40%) of lower income customers will participate in the arrears management program.

c) Please give reasons why customers who are eligible for the arrears management program would not avail themselves of it.

d) If every lower income customer with arrears greater than $180 participated in the program, please calculate the required program funding.

Response:

(a) No program to date implementing an arrearage management component has reported that a potential arrearage management credit encourages customers to incur arrears knowing that a percentage will ultimately be "forgiven."

(b) Experience in states adopting low-income affordability programs supports the conclusion that 30% of low-income customers will have arrears and that 40% of eligible customers will participate. A comprehensive library of documents was provided in response to discovery request PUB/RCM/TREE-2.

(c) Use of the term "would not" over-states program barriers. Use of the term "might not" would improve this question. Given that modification, Mr. Colton states as follows: Significant study has been devoted to why households that are eligible for particular public assistance programs do not apply for such assistance. Reasons for nonparticipation have been identified not merely for energy assistance, but also for food assistance, health insurance assistance, and income supplements. Reasons for nonparticipation in programs such as those that provide energy assistance include, but are certainly not limited to, the following:

- Lack of information about program availability;
- Lack of information about how to enroll in program;
- Cumbersome application/enrollment processes;
- Insufficient benefits to make it worthwhile;
- Inaccurate information about level of benefits;
- Misunderstanding of factors that might or might not cause program ineligibility (e.g., having wage income, having assets);
- Lack of trust in enrollment agency;
- Embarrassed by need to apply (program stigma);

- Language problems;
- Mobility problems;
- Do not want help from external entity.

(d) Calculating an answer, however, in the same fashion as was done in Mr. Colton's report, but inserting a participation rate of 100%, yields an arrearage management cost of $8.928 million.

PUB/RCM/TREE-10. Reference: Exhibit RDC-2 p.36, 54-55

a) Four principles of the crisis management program are listed on page 55. Please contrast these principles with the principles of MH's Neighbours Helping Neighbours program, and state the recommended changes that should be made to NHN.

b) On page 36, Mr. Colton criticizes MH's NHN program because it does not address the cause of the arrearage problem. Please confirm whether the proposed crisis management program addresses the cause of the arrearage problem, and if confirmed please explain how so.

c) "The crisis funding should be distributed through existing crisis intervention programs." Please confirm whether this means that MH should continue to use the Salvation Army to administer its NHN program. If not, please detail how MH should distribute its crisis management services.

d) Please provide additional support for the recommended funding of 5% of the rate affordability and arrears management programs.

Response:

(a) Unlike the MH NHN program, the crisis management program component is not offered as a stand-alone program. Instead, the crisis management initiative is one component to a comprehensive rate affordability program. It represents one tool to be directed toward the payment problem for which it is appropriate (short-term temporary crisis situation), while providing a combination of rate relief, arrearage management, and energy efficiency to address the problems for which they are appropriate. As a stand-alone program, NHN cannot operate effectively or efficiently. Changing NHN to become part of a comprehensive affordability program as discussed throughout Mr. Colton's report, a crisis program component can offer the type and level of assistance needed, can track medium and long-tem outcomes, and can address the underlying affordability problems that NHN cannot address.

(b) Mr. Colton does not propose a "crisis management program" such as NHN. He instead proposes a crisis component to a comprehensive rate affordability program. The comprehensive program proposed by Mr. Colton, of which the crisis component is but one part, addresses the cause of arrearages in that: (1) it eliminates inefficient energy consumption; (2) it gets people even to allow them to success in future bill payment; and (3) it reduces bills to an affordable level.

(c) The Salvation Army need not be excluded from being used to distribute crisis funding. The Salvation Army, however, should not be the exclusive mechanism through which crisis funding might be distributed.

(d) Experience shows that participants in low-income affordability programs make roughly 80% to 90% of their payments. Not all of the nonpayments, however, arise because of "crisis" situations. Moreover, not all nonpayers in crisis will turn to an external entity for assistance. The 5% is thus based on a balancing of these three factors: (1) the extent of nonpayment in an affordability program; (2) the extent to which nonpayment results from a crisis situation; and (3) the extent to which nonpayers can be expected to seek external assistance.

PUB/RCM/TREE-11. Reference: Exhibit RDC-2 p.55-59

a) Please justify cross-subsidizing the residential low income program using revenue from non-residential customer classes.

b) If the proposed residential low income program is funded exclusively from the Residential class, please calculate the required annual increase in the meters charge (Basic Monthly Charge) and the bill impacts for a typical base electric customer and an electric heat customer.

c) Please calculate the bill impacts for a typical Residential non-electric heat customer and a Residential electric heat customer if the meters charge is increased by the proposed amount of $1 per month.

Response:

a. Mr. Colton does not agree with the characterization in the question that a decision to have all customer classes pay for the low-income program. Any number of regulatory policies support a decision to have all customer classes help pay for the proposed low-income program. An illustrative list, without limitation to the full range of rationales that are appropriate for reaching such a decision, includes:

   - All customer classes contribute to causing the need for the low-income program, and thus all customer classes should contribute to the cost of the program.
   - All customer classes derive direct benefits from the low-income programs, and thus all customer classes should contribute to the cost of the program.
   - Nonparticipating residential ratepayers no more cause the need for, nor derive benefits from, the low-income program than do nonparticipating non-residential ratepayers. Nonparticipation is an insufficient basis upon which to ground cost responsibility.
   - The objective supported by the low-income program, universal service, is a "public good" that by its nature should be supported by all ratepayer classes (as are other utility-provided public goods).
   - The obligation to support universal service is a quid pro quo that helps compensate the community for perquisites provided by the community to the utility qua utility, including such perquisites as the right to use public rights-of-way, the right to exercise eminent domain, and the like.

b. If the program is funded exclusively through a meters charge imposed on the Residential class, the monthly meters charge would reach $2.75 per month (leaving a program deficit of roughly $84,000). The bill impact is set forth in Attachment PUB-RCM-TREE-11b.

c. The bill impact of a residential meters charge set forth at $1 per month is set forth in Attachment PUB-RCM-TREE-11c below. Information is not available to distinguish between electric base load and electric heating residential customers.

Attachment PUB-RCM-TREE-11b

Bill Impact of $1 per Month Meters Charge at Existing and Proposed Rates

		Midpoint	Existing	Proposed	SBC	% Existing	% Proposed	Total NO.	Total Pct
1	200	101	$13.16	$12.28	$2.75	20.9%	22.4%	444,258	8.4%
201	250	226	$20.98	$20.25	$2.75	13.1%	13.6%	114,854	2.2%
251	300	276	$24.10	$23.43	$2.75	11.4%	11.7%	147,620	2.8%
301	350	326	$27.23	$26.62	$2.75	10.1%	10.3%	153,008	2.9%
351	400	376	$30.35	$29.80	$2.75	9.1%	9.2%	171,518	3.3%
401	450	426	$33.48	$32.99	$2.75	8.2%	8.3%	175,599	3.3%
451	500	476	$36.60	$36.17	$2.75	7.5%	7.6%	188,741	3.6%
501	550	526	$39.73	$39.36	$2.75	6.9%	7.0%	187,183	3.6%
551	600	576	$42.85	$42.54	$2.75	6.4%	6.5%	192,806	3.7%
601	650	626	$45.98	$45.73	$2.75	6.0%	6.0%	182,364	3.5%
651	700	676	$49.10	$48.91	$2.75	5.6%	5.6%	177,975	3.4%
701	750	726	$52.23	$52.10	$2.75	5.3%	5.3%	161,498	3.1%
751	800	776	$55.35	$55.28	$2.75	5.0%	5.0%	161,811	3.1%
801	850	826	$58.48	$58.47	$2.75	4.7%	4.7%	153,246	2.9%
851	900	876	$61.60	$61.65	$2.75	4.5%	4.5%	152,155	2.9%
901	950	926	$64.74	$64.94	$2.75	4.2%	4.2%	137,631	2.6%
951	1000	976	$67.89	$68.31	$2.75	4.1%	4.0%	125,417	2.4%
1001	1100	1051	$72.61	$73.37	$2.75	3.8%	3.7%	228,924	4.3%
1101	1200	1151	$78.91	$80.12	$2.75	3.5%	3.4%	197,381	3.7%
1201	1400	1301	$88.36	$90.25	$2.75	3.1%	3.0%	310,524	5.9%
1401	1600	1501	$100.96	$103.75	$2.75	2.7%	2.7%	239,927	4.6%
1601	1800	1701	$113.56	$117.25	$2.75	2.4%	2.3%	183,021	3.5%
1801	2000	1901	$126.16	$130.75	$2.75	2.2%	2.1%	147,958	2.8%
2001 or higher		2201	$145.06	$151.00	$2.75	1.9%	1.8%	933,733	17.7%
								5,269,152	100%

	Existing
$0.0625	Block 1 (1st 900 kWh)
$0.0630	Block 2 (901 kWh or more)
6.85	Customer charge
	Proposed
$0.0637	Block 1 (1st 900 kWh)
$0.0675	Block 2 (901 kWh or more)
5.85	Customer charge

Attachment PUB-RCM-TREE-11c

Bill Impact of $1 per Month Meters Charge at Existing and Proposed Rates

		Midpoint	Existing	Proposed	SBC	% Existing	% Proposed	Total NO.	Total Pct
1	200	101	$13.16	$12.28	$1.00	7.6%	8.1%	444,258	8.4%
201	250	226	$20.98	$20.25	$1.00	4.8%	4.9%	114,854	2.2%
251	300	276	$24.10	$23.43	$1.00	4.1%	4.3%	147,620	2.8%
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901	950	926	$64.74	$64.94	$1.00	1.5%	1.5%	137,631	2.6%
951	1000	976	$67.89	$68.31	$1.00	1.5%	1.5%	125,417	2.4%
1001	1100	1051	$72.61	$73.37	$1.00	1.4%	1.4%	228,924	4.3%
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1601	1800	1701	$113.56	$117.25	$1.00	0.9%	0.9%	183,021	3.5%
1801	2000	1901	$126.16	$130.75	$1.00	0.8%	0.8%	147,958	2.8%
2001 or higher		2201	$145.06	$151.00	$1.00	0.7%	0.7%	933,733	17.7%
								5,269,152	100%

	Existing
$0.0625	Block 1 (1st 900 kWh)
$0.0630	Block 2 (901 kWh or more)
6.85	Customer charge
	Proposed
$0.0637	Block 1 (1st 900 kWh)
$0.0675	Block 2 (901 kWh or more)
5.85	Customer charge

PUB/RCM/TREE-12. Reference: Exhibit RDC-2 p.64-66

a) MH may not be permitted to share billing information, such as individual customer consumption and arrears data, with its LIEEP staff due to privacy legislation in Manitoba. One possibility is to obtain express approval from the customer to share this information. However, this does not lend itself to a mass targeting effort. Please provide alternative suggestions for targeting customers for efficiency improvements if this customer information is not available to LIEEP (efficiency program) staff.

b) Please identify barriers to participation in MH's LIEEP, since LIEEP appears to overcome the barriers to participation applicable to homeowners identified on page 66.

c) Please provide suggestions for increasing the participation rate in LIEEP. For example, MH's gas division operates a Furnace Replacement Program that is fully funded to replace many more furnaces than have been replaced to date; it appears that in this instance the barrier is customer interest, not funding.

Response:

a. Mr. Colton is not aware of legal privacy constraints that would prevent the Company from sharing individual customer consumption and arrearage data with the Company's own LIEEP staff. Nor is it evident on its face how the question defines "mass targeting effort." Accordingly, it is not possible to "provide alternative suggestions for targeting customers" if "this customer information" is not available to program staff.

   Mr. Colton believes, however, that substantial information exists on the design and delivery of low-income energy efficiency programs. Appended to this response as Attachment PUB/RCM/TREE-12a1 is one example of a compendium of low-income programs published by the American Council for an Energy Efficient Economy (ACEEE). In addition, appended to this response as Attachment PUB/RCM-TREE-12a2 is a list of evaluations of low-income efficiency and other affordability programs, which list was prepared for the U.S. Department of Energy. These attachments are not in limitation of other similar published work.

b. A discussion of the reasons for nonparticipation in programs was presented in response to PUB/RCM/TREE-9. Observations and conclusions about the specific reasons why low-income customers do not participate in the Manitoba Hydro LIEEP would require a specific additional study.

c. See, response to PUB/RCM/TREE-12(a).

PUB/RCM/TREE-13. Reference: Exhibit RDC-2 p.93

a) Please confirm whether Mr. Colton has undertaken a cost effectiveness analysis comparing Manitoba Hydro's AEP with his proposed low income program enhancements including a rate affordability program. If confirmed, please file it.

b) If the business case as suggested by Mr. Colton is cost effective enough to support the implementation of a rate affordability program and the enhancements to the other aspects of MH's low income programs, please explain why an increase to the Basic Monthly Charge is required to fund these. Put another way, if the savings from reduced collections expense, disconnections, and account write-offs are sufficient to offset the costs of the proposed programs, why is a rate increase required?

c) Please estimate the magnitude of annual savings to Manitoba Hydro in reduced collections costs, working capital, disconnection and reconnection costs, etc. if the proposed rate affordability program and other low income program enhancements are implemented. Please provide any assumptions and additional justification used in making these estimates.

Response:

a. Mr. Colton's discussion of cost-effectiveness of his proposal is presented at 69 - 101 of his report filed as an Attachment to his Direct Testimony in this proceeding.

b. This question confuses a cost-benefit analysis and a cost-effectiveness analysis. See, for example, the discussion in response to PUB/RCM/TREE-13(c). See also, the discussion at pages 86 through 95 of Mr. Colton's report (and the accompanying footnotes contained therein).

c. Mr. Colton has not calculated the magnitude of annual savings to Manitoba Hydro in reduced collections costs, working capital, disconnection and reconnection costs etc. for purposes of this proceeding, nor is it a useful exercise to attempt to do so. Framing the question of estimating annual savings is not a simple task. Asking simply whether Mr. Colton's proposed program generates savings is an inappropriate question. Instead, the more appropriate question is framed in the following two parts:

- Does the proposed comprehensive program generate savings *in achieving what*?
- Does the proposed comprehensive program generate savings *relative to what*?

Providing a comparison of the costs of Mr. Colton's program, for example, to the costs of the status quo is an inappropriate comparison. Consider that an evaluation of the Equitable Gas low-income program, undertaken for the Pennsylvania PUC, found that comparing the costs of a low-income program simply to the per unit costs of traditional collection practices captures only about one-fourth the actual administrative costs of traditional credit and collection activities. According to the Pennsylvania PUC:

> In reviewing previous studies of CAP-type programs,[1] the method of cost analysis generally employed begins by developing the costs of the alternative (here EAP).[2] Then, an attempt is made to isolate the individual costs of activities associated with traditional approaches to credit and collection for low-income payment-troubled customers, by means of estimating costs of individual (unit) activities to form an aggregate cost. And then, the two are compared.

The PUC then stated:

> As may be obvious, the weakness of the standard approach is in the costing of the traditional service effort. Historically, the 'Credit and Collections' function has existed approximately for the same duration as the utility. For the first utilities of the Atlantic states, this means that practices which made perfect sense when the utility was founded, or during a past decade when the cost reporting of such areas as 'Customer Service' or `Credit and Collections' was last systematically reviewed, continue over the years. They are integral to the yearly cycle of cost accounting and reporting. This system (as developed for firm level regulatory and financial reporting) works, so it is not changed.
>
> *Thus, while costs are properly accounted into overall FERC categories, utility accounting systems were never intended to support individual project-level testing of costs of traditional operations versus a mix of alternatives. The kind of demand placed upon cost accounting by program evaluation is very unusual in the ongoing routine of business The level of cost information required, and particularly the routine accounting of cost by low-level activity is usually not present prior to the information requests posed by program-level evaluation. Capturing the level of costs required for evaluation easily becomes an impractical project, because the amount of person-effort required is prohibitive.* (emphasis added).
>
> The bottom-up approach misses significant costs of traditional operations. *While fully adequate for traditional accounting purposes, utility cost tracking is simply not designed to facilitate direct 'what if' testing of the rationality of traditional costs at the program or project level.* (emphasis added). And, over the years, critical support costs for an operation can become institutionalized in other budgets, and so be missed. Finally, the bottom-up approach depends on developing a

[1] Pennsylvania's low-income utility programs are called CAPs (Customer Assistance Program).
[2] EAP was Equitable's CAP program. Equitable called its CAP the "Energy Assistance Program."

comprehensive list of cost categories. By the nature of this task, it is quite possible for some of the relevant categories to be missed. Not only are cost categories missed, but also the 'productivity factor' is often left out in bottom-up accounting. For example, a study of activities relevant to credit and collections might accurately state the time and cost of issuing a collections letter, but leave out the fact that one-fourth of the day's work time is not accounted for by directly relevant work tasks for which per unit costs are developed. The missing element is the productivity factor.

Given the above discussion, Mr. Colton concludes that it is not possible, or productive, to seek to calculate the "magnitude of annual savings" as suggested by the question. Not only do the existing credit and collection activities not accomplish the same objectives accomplished by the program, but neither is it possible to capture all of the appropriate costs in a comparative analysis.

Manitoba Hydro 2011 & 2012 GRA

Interrogatories of the Public Utilities Board

December 17, 2010

PUB/RCM/TREE (Chernick) 14: Reference Page 23/24 – Marginal Generation Cost

a) Please clarify your position on:

i) MH's use of "average price of energy sold under dependable export contracts" for prior two fiscal years (5.75¢/KWh 2008/09 and 2009/10 in EIIR Application).

Answer:

Historical prices are not a good proxy for future prices.

PUB/RCM/TREE (Chernick) 14: Reference Page 23/24 – Marginal Generation Cost

a) Please clarify your position on:

ii) MH's COSS use of SEP pricing and load profiles for prior 8 years when used in combination with average future total export sales prices and most recent domestic and export loads.

Answer:

Mr. Chernick supports the use of historical market price ratios among time periods to allocate generation costs to time periods, and the use of estimated class energy costs in those periods to allocate the period costs to classes.

PUB/RCM/TREE (Chernick) 14: Reference Page 23/24 – Marginal Generation Cost

a) Please clarify your position on:

iii) PUB directed COSS use of actual (current) average export prices when used in combination with SEP price and load profiles (last 8 years) for most recent domestic and export loads.

Answer:

The question appears to be focusing on the use of current export revenues in the current embedded COSS. Mr. Chernick agrees that the COSS should be allocating the current revenue requirement.

PUB/RCM/TREE (Chernick) 14: Reference Page 23/24 – Marginal Generation Cost

b) Please provide your views on the level of rigor and degree of consistency that MH should employ in cost determinations under COSS/EIIR/DSM evaluation.

Answer:

The appropriate level of rigor for any particular cost determination depends on the importance of that determination and the cost of incremental rigor.

The COSS should be based primarily on embedded costs, while rate design and DSM evaluation should reflect marginal costs. In most cases, while the values may not be equal, they should be consistent.

PUB/RCM/TREE (Chernick) 15: Reference Page 25 – DSM Marginal Cost

a) Please provide the excerpts from the referenced document Marginal Transmission and Distribution Cost Estimates SPD 04/05

Answer:

The entire document was provided by Hydro as Appendix 49 in response to RCM/TREE/MH I-7f.

PUB/RCM/TREE (Chernick) 15: Reference Page 25 – DSM Marginal Cost

b) Please provide supporting calculations with respect to the escalations in both transmission and distribution costs and cost per kilowatt hour.

Answer:

Manitoba Hydro provided the escalated marginal T&D cost per kW/year estimates in response to RCM/TREE/MH I-7f. MH failed to provide the calculation of the escalation despite RCM/TREE's request for workpapers in RCM/TREE/MH I-7h.

The T&D costs per kW.h were derived from the escalated marginal cost-per-kW/year estimates and MH's apparent assumption of a 91% load factor. Mr. Chernick backed out the 91% load factor for both transmission and distribution from the Hydro's 2004 marginal cost estimates (provided in RCM/TREE/MH II-4b) as follows:

Transmission: $67.53/kW/year ÷ ($.0085/kW.h * 8,760 hours/year) = 90.7%

Distribution: $40.93/kW/year ÷ ($.0051/kW.h * 8,760 hours/year) = 91.6%

PUB/RCM/TREE (Chernick) 16: Reference Page 25/26 – Marginal Cost of Transmission and Distribution

a) Please confirm that transmission and distribution should be independently addressed with specific load factors/losses/equipment and facility age/maintenance/etc.

Answer:

The question is not clear. It is true that the costs, load factors, equipment lives and loss factors may differ between transmission and distribution.

PUB/RCM/TREE (Chernick) 16: Reference Page 25/26 – Marginal Cost of Transmission and Distribution

b) Please explain your understanding of MH's treatment/costing approach of transmission losses as they relate to:

i) HVDC lines.
ii) HV converter stations.
iii) AC lines.
iv) AC transformer stations.

Answer:

Hydro provided its estimate of total marginal losses only. Hydro has not provided estimates of marginal transmission losses separate from distribution losses, let alone a breakdown of transmission losses among system components. Nor has Hydro explained its approach to and calculation of marginal losses.

PUB/RCM/TREE (Chernick) 16: Reference Page 25/26 – Marginal Cost of Transmission and Distribution

c) Please clarify your understanding of MH's specific distinction between facilities that relate to CP/NCP/customer classifier of:

i) Subtransmission.

Answer:

The question is not clear since the "classification" of facilities is not a marginal-cost concept.

In its marginal cost analysis (Appendix 49), Hydro distinguishes between load-related or non-load-related investment. The load-related T&D investment is assumed to be driven by winter coincident peak. Hydro treats investment as non-load-related for many reasons (for example, investment that are already committed and installations to address reliability or safety concerns). For more detail about Hydro's determination of load-related T&D investment, see Appendix 49.

For an explanation of how MH functionalizes, classifies and allocates T&D investment in its COSS, see Appendix 11.1 of the Company's filing.

PUB/RCM/TREE (Chernick) 16: Reference Page 25/26 – Marginal Cost of Transmission and Distribution

c) Please clarify your understanding of MH's specific distinction between facilities that relate to CP/NCP/customer classifier of:

ii) Substations/line transformer.

Answer:

See the response to PUB/RCM/TREE (Chernick) 16b.

PUB/RCM/TREE (Chernick) 16: Reference Page 25/26 – Marginal Cost of Transmission and Distribution

c) Please clarify your understanding of MH's specific distinction between facilities that relate to CP/NCP/customer classifier of:

iii) Distribution lines and poles.

Answer:

See the response to PUB/RCM/TREE (Chernick) 16b.

PUB/RCM/TREE (Chernick) 16: Reference Page 25/26 – Marginal Cost of Transmission and Distribution

d) What is your view of the use of M/C in a COSS process and in particular, how should exports share in the marginal cost of new generation (Wuskwatim / Keeyask / Conawapa) or new transmission (Bipole III)?

Answer:

Marginal costs have little role in the COSS process.

To the extent that generation and transmission are being added, expanded or advanced to support exports, export costs should at least cover the incremental costs.

The allocation of embedded costs to exports does not determine export revenues or the share of costs paid by export customers. It does affect the allocation of net costs among retail classes. For the embedded COSS, costs should be allocated to exports in the same manner that they are allocated to retail classes.

PUB/RCM/TREE (Chernick) 17: Reference Page 27 – DSM Table 1: Distribution Losses

Please provide illustrative calculations demonstrating that the marginal distribution losses would be considerably greater than average losses.

Answer:

See next page. The computation assumes that average losses are 8%, of which 1% are fixed core losses in transformers and the rest are variable losses. Marginal losses at any load level equal twice the average losses; since losses vary with the square of load (loss = $a + b \times \text{load}^2$), marginal losses at any load ($2 \times b \times \text{load}$) are twice the average variable losses ($b \times \text{load}$).

Load Segment	% of average load	% or hours	No-load Losses as % of		Average Load Losses as % of		Total Losses as % of		Marginal Losses as % of	
			Average Load	Segment Load	Average Load	Segment Load	Average Load	Segment Load	Average Load	Segment Load
High	150%	15%	1.0%	0.7%	15.8%	10.5%	16.8%	11.2%	31.5%	21.0%
Medium	100%	60%	1.0%	1.0%	7.0%	7.0%	8.0%	8.0%	14.0%	14.0%
Low	70%	25%	1.0%	1.4%	3.4%	4.9%	4.4%	6.3%	6.9%	9.8%
average	100%									
Annual hour-weighted average			1.0%	1.1%	7.4%	7.0%	8.4%	8.1%	14.8%	14.0%
Annual sales-weighted average				1.0%		7.4%		8.4%		14.8%

PUB/RCM/TREE (Chernick) 18: Reference Page 28/29 - Marginal Cost of Firm Generation

a) Please explain how MH should determine and apply M/C in today's energy market using:

i) Existing contract peak energy prices – 5-6¢/KWh.
ii) Average opportunity sale export prices - <4¢/KWh.
iii) Off-peak (night-time) export prices – 1-2¢/KWh.
iv) New (future) hydraulic G&T cists - >9¢/KWh.
v) Imports – 2-5¢/KWh.
vi) Thermal generation (SCCT) - 10¢/KWh.
vii) Average embedded G&T costs – 3-6¢/KWh.
viii) Average embedded distribution costs – 2-3¢/KWh.

Answer:

The question does not specify what issues it is interested in applying marginal costs (if that is what M/C means) to, so detailed responses are not possible.

In general, existing contract prices (item i) are not relevant to rate design or DSM evaluation, since they are committed. In some cases, aspects of existing contract prices may be useful in time differentiation or other features of marginal costs, if the existing contracts appear to be predictive of future prices.

Current and recent opportunity prices for imports and exports (items ii, iii, and v) may be useful in time differentiation of marginal costs, if current conditions appear likely to continue.

The costs of new power supply that Hydro intends to develop (e.g., item iv) represent a floor on marginal costs; the value of power freed up for export should be at least that high.

The cost of an SCCT (item vi) may be relevant in pricing peak capacity and standby energy reserves.

Average embedded costs (items vii and viii) are not generally relevant inputs to marginal-cost determination.

PUB/RCM/TREE (Chernick) 19: Reference Page 29 –Marginal Cost

a) Please indicate to what extent the "conventional pollutants are internalized" for US Utilities in the MISO Region and describe the current cap and trade systems in place.

Answer:

NOx and SO_2 costs have been largely internalized by cap and trade rules. New emissions regulations may reduce those prices so far that the allowance systems no longer effectively internalize the costs. Other emissions and environmental effects (e.g., particulates, mercury, greenhouse gases) have not been internalized, but some MISO states are involved in efforts that may result in a greenhouse cap-and-trade system.

PUB/RCM/TREE (Chernick) 19: Reference Page 29 –Marginal Cost

b) Please discuss the concept of "social cost" of domestic consumption of electricity versus direct costs.

Answer:

Social costs include direct costs, plus environmental effects and (depending on who is defining "social") sometime other effects on third parties (i.e., other than Hydro and its customers as customers).

PUB/RCM/TREE (Chernick) 20: Reference Page 29/30 -Tail Block Rates

a) Please explain why MH customers should:

i) Pay tail block rates in excess of current average export price (plus distribution costs).

Answer:

Rate design affects long-term energy decisions (e.g., fuel choice, efficiency levels) as well as short-term energy decisions. Offering customers the opportunity to use additional energy at prices well below the price of future exports would result in the commitment of some energy to domestic use at low prices that customers would not purchase if they faced the full value of the energy. The same is true if customers are offered energy at prices below the cost of new supplies.

<u>PUB/RCM/TREE (Chernick) 20: Reference Page 29/30 -Tail Block Rates</u>

a) Please explain <u>why</u> MH customers should:

ii) Pay rates that reflect new G&T (incremental) costs in excess of export market prices (on an extended basis).

<u>Answer:</u>

The cited testimony compares Hydro's estimates of marginal costs to tailblock rates. Tailblock rates may set at marginal costs without increasing total bills.

The cited testimony does not assert that "MH customers should pay rates that reflect new G&T (incremental) costs in excess of export market prices (on an extended basis)."

It is not clear why Hydro would commit to exports at prices below the incremental costs of building or advancing new G&T. Once Hydro has committed to exports at a certain price, marginal cost should be based on the cost of new marginal resources to meet total load commitments (domestic and export), which may be higher or lower than embedded contract prices.

PUB/RCM/TREE (Chernick) 20: Reference Page 29/30 -Tail Block Rates

a) Please explain why MH customers should:

iii) Should subsidize U.S. clean energy programs by exporting additional (DSM created) energy while periodically importing fossil fuel energy (coal and/or natural gas) to cover shortages.

Answer:

Energy efficiency (due to DSM programs or improved rate design) would result in increased export revenues and reduced fossil imports. Hydro periodically imports fossil energy due to drought. In some situations, Hydro imports fossil-fueled power off peak and exports the energy back to the US or other provinces on peak.

It is not clear what subsidy is assumed in the question.

PUB/RCM/TREE (Chernick) 21: Reference Page 31 – Avoided Cost

Please file in an electronic format, the referenced document that describes the derivation of avoided costs in California.

Answer:

The report is attached as PUB RCM TREE(Chernick)-21 Attachment. Note that large amounts of documentation are available at http://www.ethree.com/public_projects/cpuc5.html.

<u>PUB/RCM/TREE (Chernick) 21: Reference Page 31 – Avoided Cost</u>

Please file in an electronic format, the referenced document that describes the derivation of avoided costs in California.

<u>Answer:</u>

The report is attached as PUB RCM TREE-21. Note that large amounts of documentation are available at http://www.ethree.com/public_projects/cpuc5.html.

PUB/RCM/TREE (Chernick) 21: Reference Page 31 – Avoided Cost

Please file in an electronic format, the referenced document that describes the derivation of avoided costs in California.

Answer:

The report is attached as xx. Note that large amounts of documentation are available at http://www.ethree.com/public_projects/cpuc5.html.

PUB/RCM/TREE (Chernick) 22: Reference Page 32 – Environmental Costs Recovery

a) Please provide your rationale for clean energy supporting (if you do) MH's new generation and transmission capital projects and outline your view on appropriate process for cost allocations to:

i) Residential rates.
ii) Commercial rates.
iii) Industry rates.
iv) Export contracts.

Answer:

Mr. Chernick does not understand this question. Hydro allocates all generation and HVDC transmission costs on weighted energy and all AC transmission on the average of summer and winter coincident peak (Appendix 11.1). Some additional transmission might be allocated on energy. Mr. Chernick does not advocate using different allocators for new and existing plant.

PUB/RCM/TREE (Chernick) 22: Reference Page 32 – Environmental Costs Recovery

b) In the absence of CO_2 legislation, how can MH achieve additional revenue from opportunity sales into the MISO market?

Answer:

The price of opportunity sales may be increased by the purchasers' needs to meet state renewable-energy and/or greenhouse-gas requirements.

PUB/RCM/TREE (Chernick) 23: Reference Page 32 – Environmental Costs Recovery

a) Please indicate to what extent MH's clean hydraulic energy should qualify for renewable energy credits in the various state(s) programs.

Answer:

Many states exclude large hydraulic plants from renewable portfolio standards, due to concerns about the environmental effects of large hydraulic plants. Most renewable portfolio standards also exclude existing generation, since the purpose is to encourage new development, rather than reassignment of rights to existing generation. Both of these features seem reasonable.

PUB/RCM/TREE (Chernick) 23: Reference Page 32 – Environmental Costs Recovery

b) Please explain your understanding of the specific positions taken by Minnesota/Wisconsin/North Dakota on the issue of "clean hydro" and the availability of renewable energy credits for "clean hydro".

Answer:

Mr. Chernick has not reviewed the "specific positions taken by Minnesota/Wisconsin/North Dakota on the issue of "clean hydro" and the availability of renewable energy credits for "clean hydro." According to a summary by the Pew Center on Global Climate Change (http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm), North Dakota has only voluntary renewable standards. Both Minnesota and Wisconsin have mandatory renewable standards and limit qualifying hydro to 60 MW.

PUB/RCM/TREE (Chernick) 24: Reference Page 35 – Baseline of New Customers

a) Please indicate what characteristics should be utilized to determine the comparable efficient customers, where a new customer needs to establish a baseline to ensure comparability.

Answer:

The baseline could be computed with energy modeling software for the type of building and usage of the new customer, or by comparison with efficient customers (as determined by Power Smart audits) of the same business type (office, restaurant, supermarket, general retail, etc.).

PUB/RCM/TREE (Chernick) 24: Reference Page 35 – Baseline of New Customers

b) Please indicate the options available for defining new customers.

Answer:

Mr. Chernick would define a new customer in terms of new construction, rather than change of ownership. The rules for whether customers will be allowed to carry their baseline one location to another, and whether the baseline associated with a location and meter will automatically transfer to a new customer at the same location, would need to be worked out in consultation with Hydro.

PUB/RCM/TREE (Chernick) 24: Reference Page 35 – Baseline of New Customers

c) Please provide your suggestion on how major expansion of existing facilities should be treated as compared to other causes of increased consumption.

Answer:

In the interests of equity, Mr. Chernick would support treating major expansion of existing facilities in the same manner as new customers.

PUB/RCM/TREE (Chernick) 24: Reference Page 35 – Baseline of New Customers

d) Please provide your recommendation on how such a rate structure should be implemented.

Answer:

Mr. Chernick recommends that Hydro be directed to work with consumer groups to develop a proposal for a two-part rate design.

PUB/RCM/TREE (Chernick) 25: Reference Page 41 – TOU Rate Proposal

Please provide a full description of the approach being considered in California and indicate the current status of such approach.

Answer:

According to the California PUC's press release (May 26, 2010),

On May 1, 2010, most large customers with an energy demand greater than or equal to 200kW were switched to the new Peak Day Pricing (PDP) rate. Customers have the choice to opt off the rate and remain on a Time of Use rate. The PDP rate impacts approximately 2,200 PG&E customers on rate schedules E-19, E-20, E-37, and A-10, which includes manufacturers, hotel chains, school districts, hospitals, and office buildings among others, but not residential customers. PDP provides a lower rate from May through October in exchange for a higher rate from 2 p.m. to 6 p.m. on nine-to-15 peak event days per year. This new rate could lower a customer's bill from May through October if they sufficiently reduce their electricity use from 2 p.m. to 6 p.m. on peak event days. Other customers will save simply by being on the rate. PG&E will notify customers the day before a peak event day, so that they can plan accordingly.

PG&E may call a peak event day when they expect the demand for electricity the next day to be exceptionally high. In the past, customers received a "Flex Alert" requesting that they lower electricity use. Businesses on PDP that altered their use in response to "Flex Alerts" now have an opportunity to save money by taking similar actions on PDP days.

The intent of this rate is to reduce demand during those times of the year when demand for electricity is the highest. If customers can collectively reduce the peak demand for electricity, they can help improve reliability of the grid, decrease the need for additional power plants, and reduce greenhouse gases. Although PDP is currently only available to very large usage customers of PG&E, all non-residential customers will have rate options by the end of 2011.

PG&E's summary of the PDP rate are provided at
http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/facts/charges/index.shtml

PG&E's describes aspects of the program at
http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/details/, including the following:

> An Event Day is when customers will see additional charges for energy use during peak hours of 2 p.m. to 6 p.m. (or optional 12 p.m. to 6 p.m. for A-1, AG-4, A-6, A-10 rates schedules). On all other times, customers will be charged their normal Time of use (TOU) rates. And, from May through October, customers will receive credits on their energy use.
>
> PG&E will call a minimum of 9 and a maximum of 15 Event Days per year. Event days are generally triggered by high temperature, but California ISO system emergencies and market-price conditions may also lead to an event.
>
> Event days are called with 24-hour notice. PG&E will send a notice through one or more channels of your choosing to alert you when an Event Day has been called. PDP participants are encouraged to drop and/or shift energy use away from peak hours on Event Days.

Reservation capacity allows customers on E-19, E-20 and AG-5C rate schedules to pay fixed charges for a designated portion of their energy use while only being exposed to higher PDP prices for the portion that exceeds their fixed reservation level. Participants must pay the generation portion of the demand charge if the measured peak demand in a given summer bill period is less than the capacity they reserved. If participants do not specify a reservation capacity value at the time of sign up, it will automatically be set to 50% of their average peak-period maximum demand during the previous six summer months.

Customers who enroll on the AG-4 PDP tariff may elect to participate on alternate Event Days, as opposed to every Event Day. This option may be helpful for customers that find it challenging to shift or reduce load for multiple days in a row. If your business selects this option, the PDP charges will apply only on alternate Event Days, and the customer credits amount is set at 50 percent of the standard amount.

Customers who enroll on the AG-4 PDP tariff may elect to extend the time in which additional charges are incurred on an Event Day. This option may be helpful for customers who have the flexibility to reduce energy consumption for longer periods of time on Event Days. If your business selects this option, the Event window will increase to six hours total (12:00 p.m. to 6:00 p.m.), but your PDP charges will drop by one-third during Event hours.

Southern California Edison's description of its similar Critical Peak Pricing program is attached as PUB RCM TREE(Chernick)-25 Attachment.

PUB/RCM/TREE (Chernick) 26: Reference Page 41 – Use of Export Revenues

Please explain how the use of export revenues could be applied to reduce the tax burden of Manitoba businesses and households and describe where such a scheme is currently in place in other jurisdictions.

Answer:

Hydro might pay for services that are currently funded through taxation, the Province might impose a tax on Hydro sales or revenues, or a portion of Hydro's retained earnings (once those are more than adequate) can be transferred to the provincial coffers.

Not all jurisdictions face Manitoba's happy problem of having large energy resource potential at costs below market prices. The examples Mr. Chernick is aware of are BC and Quebec with respect to electricity; Alaska, Russia and other exporters with respect to oil; Russia, Alberta, and some US states with respect to natural gas; and some US states with respect to coal.

In many cases, the exporting jurisdictions apply extraction taxes, royalties, or export taxes to capture a portion of the difference between market value and production cost. It is Mr. Chernick's understanding that OPEC countries generally charge extraction taxes on foreign oil companies, while Russia imposes export taxes on fuel and Alaska charges a production tax on oil and gas. In the case of government-owned energy companies, the profits of the energy company may flow directly to the national treasury. Many oil exporters in the Middle East support their governments entirely with energy revenues, and about 90% of Alaska's revenues are from oil taxes and fees. Many US states charge severance taxes on oil, gas, and/or coal.

PUB/RCM/TREE (Chernick) 27: Reference Pages 44/45 – DSM Savings and Spending Rates

a) Please provide a table indicating the level of DSM spending per customer for each jurisdiction listed in Tables 4 and 5 and comment on the level of spending by MH versus this peer group.

Answer:

The table is shown below. The numbers speak for themselves. Utilities with smaller customers spend less per customer that those with larger customers, all else equal.

State	Total Retail Sales (MWh)	2009 Budget $M	Budget per MWh	Total Customers	Budget per customer	Retail Revenues $k	EE as % revenue
VT	5,496,513	$30.70	$5.59	296,822	$103	390,304	8%
RI	7,617,629	$29.50	$3.87	434,888	$68	587,288	5%
CA	259,583,623	$998.30	$3.85	11,962,235	$83	18,663,603	5%
HI	10,126,185	$35.50	$3.51	366,698	$97	749,844	5%
MA	54,359,198	$183.80	$3.38	2,635,357	$70	4,020,326	5%
NY	140,034,397	$378.30	$2.70	7,126,416	$53	12,119,201	3%
CT	29,715,764	$73.40	$2.47	1,436,827	$51	2,489,109	3%
ME	11,282,967	$20.80	$1.84	657,008	$32	881,904	2%
OR	47,566,897	$84.70	$1.78	1,357,492	$62	1,796,594	5%
NJ	75,779,853	$132.30	$1.75	3,305,859	$40	5,707,435	2%
MN	64,004,463	$111.20	$1.74	1,985,422	$56	2,516,171	4%
UT	27,586,700	$45.40	$1.65	634,598	$72	841,129	5%
WA	90,164,701	$146.50	$1.62	2,254,257	$65	3,091,876	5%
WI	66,286,439	$101.10	$1.53	2,259,427	$45	2,640,811	4%
NH	10,698,493	$15.20	$1.42	564,393	$27	816,302	2%
ID	22,753,779	$31.50	$1.38	479,130	$66	684,511	5%
IA	43,641,195	$55.60	$1.27	1,310,404	$42	1,744,627	3%
NV	34,283,654	$41.90	$1.22	562,115	$75	879,817	5%
MB	24,080,000	$27.70	$1.15	427,472	$65	1,161,000	2%

PUB/RCM/TREE (Chernick) 27: Reference Pages 44/45 – DSM Savings and Spending Rates

b) Please re-file table 5 incorporating the ratio of total $DSM spending to total revenue and comment on MH's relative ranking.

Answer:

See response to 27(a). Hydro's low rates result in higher ratios of DSM spending to revenue than for a jurisdiction with higher rates.

PUB/RCM/TREE (Chernick) 28: Reference Pages 44/45 – DSM Programs

Please describe the regulatory mechanisms are in place in the jurisdictions listed in Tables 4 and 5 to compensate investor owned utilities for undertaking DSM programs which reduce revenues.

Answer:

Most of these states have some form of lost-revenue recovery or revenue decoupling, and many have some form of shareholder incentive. See the State Energy Efficiency Scorecard, ACEEE, Table 12 for one assessment. That report is attached.

xx

PUB/RCM/TREE (Chernick) 29: Reference Pages 44/45 – Saving/Spending (DSM)

a) In its response to PUB/MH II-94, MH explains that the decrease in residential energy and demand savings is due to federal lighting efficiency regulations that are coming into effect. Please identify any jurisdictions listed in Tables 4 and 5 where similar regulations are coming into effect, and whether those jurisdictions phase out the impact on energy savings in the same manner that MH does.

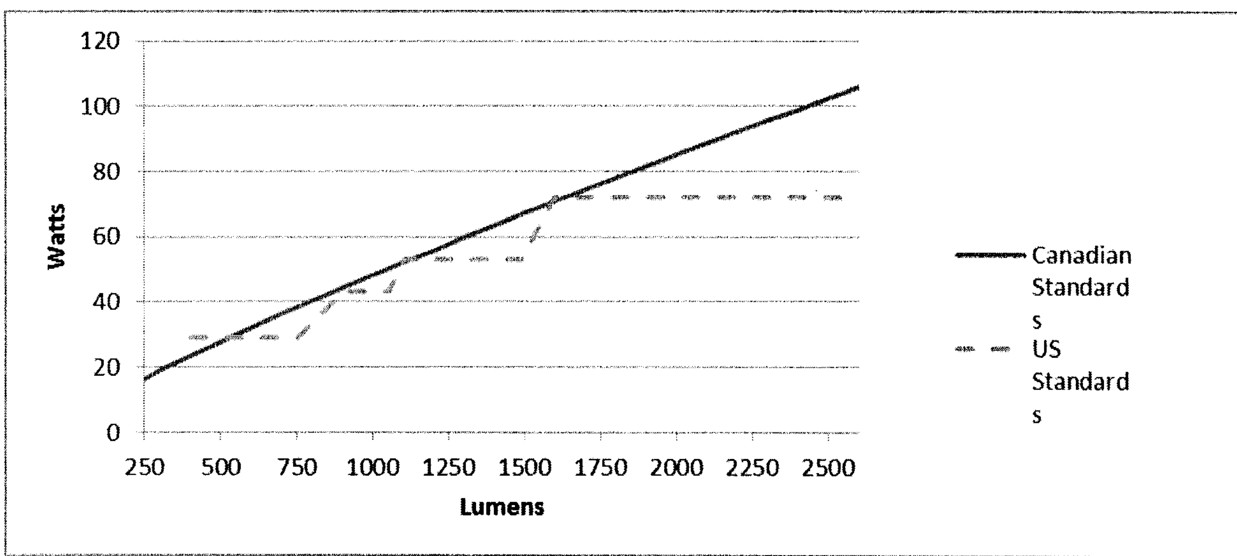
Answer:

All US jurisdictions are covered by the federal lighting efficiency regulations pursuant to the Energy Independence and Security Act of 2007 (§321), which cover incandescent and fluorescent lighting in residential and commercial applications, phasing in during 2012–2014. See also http://www1.eere.energy.gov/buildings/appliance_standards/residential/incandescent_lamps.html for more information on the US Federal standards.

California has more stringent lighting standards.

As shown below, the US standards are generally more stringent than the Canadian standards.

All the jurisdictions listed in Table 4 are aware of the Federal lighting standards. The savings targets reflect the loss of the easy lighting savings and the need to increase savings from more difficult applications and end uses.



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PUB/RCM/TREE (Chernick) 29: Reference Pages 44/45 – Saving/Spending (DSM)

b) Please confirm whether the other jurisdictions in Tables 4 and 5 identify the energy savings impact of changes to Codes and Standards separately from their incentive program DSM energy savings.

Answer:

The DSM program savings do not include the impacts of changes to Codes and Standards. Some jurisdictions have explicit estimates of code and standard effects, but those are not part of DSM program savings.

PUB/RCM/TREE (Chernick) 29: Reference Pages 44/45 – Saving/Spending (DSM)

c) Please provide the comparable DSM savings rates and spending rates for BC Hydro and Hydro Quebec.

Answer:

BC Hydro's annual DSM program savings are difficult to parse out, since BC Hydro includes codes, standards and rate design in some of its DSM savings. Over the period 2009–2020, BC Hydro appeared to have planned on about 0.8% of sales per year from programs in its 2008 LTAP. The BCUC expressed doubt that the proposed level of DSM represented all cost-effective DSM. (2008 LTAP Decision, July 27, 2009, p. 85)

BC Hydro budget for FY2009 was $137.2 million, or about $2.50/MWh of sales.

From the HQ Strategic Plan 2009–2013 (p. 5), the incremental energy savings projected as a percent of retail sales is as shown in the following table:

2009	2010	2011	2012	2013	2014
0.4%	0.5%	0.6%	0.6%	0.6%	1.6%

HQ budgeted $280 million in 2009 (ibid., p. 50), or $1.71/MWh.

PUB/RCM/TREE (Chernick) 30: Reference Pages 46 – Cost Effectiveness (DSM)

a) In a strictly qualitative sense, please identify the marginal benefits that would be used by PG&E, Efficiency Vermont, and Xcel Energy in their DSM cost effectiveness tests, and contrast those with the marginal benefits identified by MH in Appendix 9.1, (Pages 21 to 23) that are used in its DSM cost effectiveness tests.

Answer:

Qualitatively, the categories of benefits used in California, Vermont, and Manitoba are similar: market energy and capacity values, avoided transmission and generation costs, and line losses. Vermont adds 5% to direct avoided costs to reflect unquantified environmental benefits, and reduces the costs of energy-efficiency measures by 10% to reflect risk-reduction benefits. Mr. Chernick is not familiar with the avoided costs used by Xcel.

Note that the focus on PG&E, Efficiency Vermont, and Xcel Energy is from a Hydro document, Appendix 25. The Board may want to ask Hydro's consultants (Dunsky, et al.) to make these comparisons.

PUB/RCM/TREE (Wallach) 31 **Reference: Page 5 – Financial Risk - Drought**

Did JW confirm that MH looks to maximize net export revenue and not maximize gross export revenue.

ANSWER:

Mr. Wallach was unable to independently confirm that the various production and planning models used by Manitoba Hydro seek to maximize net revenues, since he was denied access to documentation regarding these models. However, both the KMPG and KM Reports confirm that the optimization logic in the Company's models is designed to maximize net revenues. For example, the KPMG Report (p. 38) describes the optimization logic for the SPLASH model as follows:

> Thereafter, the system's linear programming logic is designed to maximize net revenues. The optimization of net revenues considers the economic opportunities associated with surplus hydro energy that is available for flows greater than the drought flows.

PUB/RCM/TREE (Wallach) 32 **Reference: Page 8, Higher Import Prices**

a) Please expand on the appropriate export/import price ratios that would apply to:

   i. High flow scenario

   ii. Medium flow scenario

   iii. Low flow scenario

   iv. Dependable flow scenario

b) Please discuss the export/import relationship with respect to:

   i. High and low natural gas prices

   ii. $0.0/$30/$60/ tonne CO_2 pricing

ANSWER:

(a) Mr. Wallach does not understand what is meant by the term "export/import price ratios" or how such ratios might apply to or vary with changes in water flows.

(b) Mr. Wallach does not understand what is meant by the phrase "export/import relationship." Assuming that the phrase refers to the relationship between export and import prices in the MISO market, Mr. Wallach's response is that the relationship depends on a number of factors. In general, at any one point in time, there is a single locational marginal price at each node, hub, or interconnection. In other words, one would expect that a 1 MWh export into MISO would be paid the same hourly market price as that paid for a 1 MWh import from MISO in the same hour. However, according to Manitoba Hydro, exports are transacted predominantly during on-peak hours, while imports are predominantly transacted during off-peak hours. Consequently, one would expect that the *average* price paid for exports over a month or year would be higher than the *average* price paid for imports over that same time period.

Moreover, one would expect that high natural gas prices would lead to high prices in more on-peak hours, when natural-gas resources are more likely to set the market-clearing price, than in off-peak hours. Thus, high natural-gas prices would likely increase average export prices more than average import prices. Conversely, one would expect that carbon pricing would lead to higher prices in more off-peak hours, when coal resources are more likely to be on the margin, than in on-peak hours. Thus, carbon price would likely increase average import prices more than average export prices.

PUB/RCM/TREE (Wallach) 33 **Reference: Page 9, Alternative Development Scenario**

a) Please confirm that MH's alternative development sequence has a more favorable debt ratio as well as substantially lower level of total debt than the development scenario reflected in IFF 09–1.

b) Please confirm that MH's alternative development sequence has lower retained earnings then IFF 09–1.

c) Please confirm that the lower firm export commitments under the alternative development sequence would permit MH to retain lower retained earning reserves.

ANSWER:

(a) Based on data provided in IFF09-1 and in Appendix 15 to the Company's General Rate Application ("20 Year Financial Outlook Alternative Scenarios"), Mr. Wallach can confirm that the Company forecasts lower amounts of long-term debt for electric operations for the alternative development sequence than for the recommended development plan from Fiscal Year 2011/12 through Fiscal Year 2019/20.

As far as Mr. Wallach is aware, IFF09-1 does not provide the projected debt ratios for electric operations. However, based on his own calculations, Mr. Wallach can confirm that the Company forecasts slightly lower long-term debt ratios for electric operations for the alternative development sequence than for the recommended development plan in both Fiscal Year 2011/12 and Fiscal Year 2019/20.

(b) Based on data provided in IFF09-1 and in Appendix 15 to the Company's General Rate Application ("20 Year Financial Outlook Alternative Scenarios"), Mr. Wallach can confirm that the Company forecasts lower amounts of retained earnings for electric operations for the alternative development sequence than for the recommended development plan from Fiscal Year 2012/13 through Fiscal Year 2019/20.

(c) Mr. Wallach does not have access to the forecast data that would allow him to independently determine whether Manitoba Hydro would be able to maintain lower retained earnings under the alternative development sequence than under the recommended development plan.

PUB/RCM/TREE (Wallach) 34 **Reference: Page 10, Risk Mitigation Measures**

Please provide a comparison of the alternative risk mitigation measures versus those proposed by KM and explain how the proposed measures are less expensive than those proposed by KM.

ANSWER:

Mr. Wallach did not recommend specific alternative risk-mitigation measures in his direct testimony. Instead, he recommended that, to the extent that drought risks are deemed to be unsustainable, the Company evaluate whether there are risk-mitigation measures – such as portfolio diversification – that would be less expensive to implement than the insurance measures proposed in the KM Report.

PUB/RCM/TREE (Wallach) 35 **Reference: Page 12**

a) Please confirm that in a drought that is more severe than the worst recorded and MH would be faced with:

   i. Costs at least equal to the worst drought on record if all mitigation clauses were fully effective.

   ii. Costs considerably greater than those for the worst drought on record if mitigation clauses were not effective.

b) Please speculate on whether there would have been potentially higher costs in 2003/04 if all imports had attracted day ahead market prices [instead of buyback prices achieved by MH].

ANSWER:

(a) Mr. Wallach is unable to independently confirm these assertions, since (1) he does not understand what is meant by the term "mitigation clauses"; and (2) he does not have access to the forecast data that would allow him to determine what system costs would be under drought conditions.

(b) Mr. Wallach is unable to meaningfully speculate on this issue, since (1) MISO had not yet implemented a centralized day-ahead market in 2003/04; and (2) Mr. Wallach does not have access to the buyback prices paid by Manitoba Hydro at that time.

PUB/RCM/TREE (Wallach) 36 **Reference: Pages 16- 18 Import Price Risk**

a) Please confirm that MH's quantitative analysis of risk exposure in IFF09-1 did not include import price variations for all scenarios and in particular drought

b) Please indicate HW's understanding of the relative import prices employed by KPMG in arriving at negative retained earnings of $1.1 billion.

ANSWER:

(a) The description of the risk scenarios in IFF09-1 does not make any mention of sensitivities on import prices. However, Mr. Wallach does not have access to the data that would allow him to definitively determine whether these risk scenarios incorporated import-price sensitivities.

(b) Mr. Wallach does not know what import prices were used in the KPMG risk analysis or how such prices were derived, since he was denied access to this data as well as the model assumptions, algorithms, and outputs relied on by KPMG to forecast import prices for its risk analysis.

PUB/RCM/TREE (Wallach) 37 **Reference: Page 17, Retained Earnings level**

Please indicate to what extent compensating increases would be required to reinstate pre-drought retained earnings levels.

ANSWER:

According to IFF09-1, Manitoba Hydro would need to increase rates by 3.37% in each year of the five-year drought (over and above the base case annual rate increases) in order to restore retained earnings to pre-drought levels by the end of the drought.

PUB/RCM/TREE (Wallach) 38 **Reference: Page 23 Modeling Changes**

a) Please explain how PRISM should be utilized to determine whether sensitivity scenarios are reasonably stressful.
b) Please provide examples of how the PRISM representation of system conditions could be improved.
c) Please indicate what would be a recommended length of the planning horizon.
d) Please elaborate on which input variables should be subject to Stochastic treatment and explain the benefits of such an approach.

ANSWER:

(a) For example, one possible approach for testing the stressfulness of the IFF09-1 five-year drought sensitivity would be to determine from a PRISM simulation the expected value, and the distribution around that expected value, of cumulative net revenues over the five-year planning period used in the PRISM model. This distribution could then be used to estimate the variation in net revenues from the mean at any confidence level or the difference in net revenues between the mean and average net revenues for, e.g., the worst 10% outcomes. This statistic could then be compared against the cumulative decline in net revenues (relative to the IFF09-1 baseline scenario) estimated under the IFF09-1 five-year drought sensitivity to assess the likelihood of the forecasted results from the IFF09-1 five-year drought sensitivity.

(b) Mr. Wallach did not have access to detailed documentation regarding the PRISM model. Therefore, Mr. Wallach did not make specific recommendations for modifying PRISM, but instead made the general recommendation that the Company make whatever modifications would be appropriate to more fully integrate stochastic modeling into the Company's risk analyses. As discussed on page 24 of Mr. Wallach's direct testimony, the Company is currently developing a new risk-assessment model in order to more fully integrate stochastic modeling in its risk analyses.

(c) On page 24 of his direct testimony, Mr. Wallach recommends that the Company incorporate its new risk model in its long-range resource planning process. Consistent with this recommendation, it would be appropriate for the new risk model to utilize a planning horizon consistent with that assumed for resource-planning purposes.

(d) Mr. Wallach did not have access to detailed documentation regarding the stochastic representation of input variables for the PRISM model. The only publicly available documentation was an overview of the PRISM model provided in Appendix 31 of the Company's General Rate Application ("Risk Analysis Using PRISM"). Based on the information provided in Appendix 31, it appears that inputs for load (in the first year), water flow (in the first year), natural-gas prices, electricity spot-market prices, and wind generation are represented stochastically in PRISM. Other potential candidates for probabilistic representation would include: annual load growth, carbon pricing, electricity forward-market prices, new-resource construction costs, interest rates, and exchange rates.

PUB/RCM/TREE (Wallach) 39 **Reference: Page 23 Modeling Changes**

Please explain how MH should apply Stochastic modeling in the Resource Planning Process and describe how the Corporation will be able to utilize such information to identify an optimal portfolio plan at a sustainable level of risk.

ANSWER:

In general, the objective would be to compare alternative resource plans not just on the basis of their long-term expected costs, but also on the basis of the risk that long-term costs will exceed expected values. For example, two resource plans might have very similar expected net present value costs, but a very different range of cost outcomes: one with significant variation in cost outcomes in excess of expected cost, and the other showing little such variation. In determining which of these two plans is preferred, the Company would consider the extent to which the latter plan is less risky than the former.

PUB/RCM/TREE (Wallach) 40   Reference: Page 28, Long Term Contracts

a) Please confirm that MH's past inclination to not invoke contract conditions allowing at least partial curtailments substantially reduce the value of long-term contracts.

b) Please comment on MH's ability to anticipate droughts and to trigger "Adverse Water" or other curtailment clauses in a timely fashion.

ANSWER:

(a) Mr. Wallach is unable to confirm this assertion, since he has no knowledge regarding "MH's past inclination to not invoke contract conditions allowing at least partial curtailments."

(b) Mr. Wallach does not have any information in his possession with regard to Manitoba Hydro's ability to anticipate droughts.

PUB/RCM/TREE (Wallach) 41 **Reference: Page 35 Risk Mitigation Measures**

a) Please provide a comparison, (order of magnitude) of the anticipated costs of each risk mitigation measure as an alternative to those proposed by KM.
b) In light of existing climate change legislation in Manitoba, please explain what form of efficient MH as a risk mitigation measure should consider thermal generation resources.

ANSWER:

(a) See the response to PUB/RCM/TREE (Wallach) 34.

(b) Mr. Wallach does not understand what is being requested in this question.